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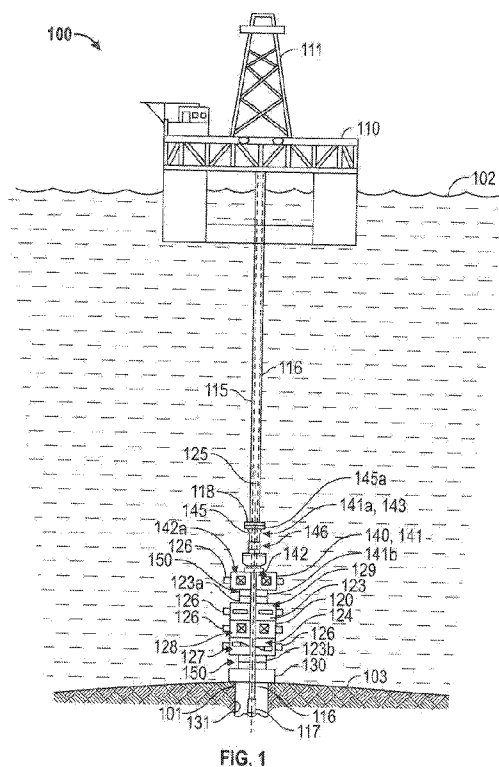
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[Continued on next page]

(54) Title: SUBSEA CONTAINMENT CAP ADAPTERS



(57) Abstract: A method for controlling hydrocarbons flowing from a sub-sea structure comprises lowering an adapter from the surface to a subsea structure. The adapter has a through bore extending between an upper connector having a first connector profile and a lower connector having a second connector profile that is different than the first connector profile. In addition, the method comprises coupling the lower connector of the adapter to the subsea structure. Further, the method comprises lowering a containment cap from the surface to the adapter. Still further, the method comprises coupling the containment cap to the upper connector of the adapter.



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SUBSEA CONTAINMENT CAP ADAPTERS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims benefit of U.S. provisional patent application Serial No. 61/500,679 filed June 24, 2011, and entitled "Subsea Containment Cap Adapter," which is hereby incorporated herein by reference in its entirety. This application also claims benefit of U.S. provisional patent application Serial No. 61/498,269 filed June 17, 2011, and entitled "Air-Freightable Containment Cap for Containing a Subsea Well," 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] The invention relates generally to systems and methods for containing a subsea wellbore that is discharging hydrocarbons. More particularly, the invention relates to systems and methods for capping a subsea wellbore using a containment cap and coupling the cap to any of at least four different subsea structures: the wellhead, the blowout preventer (BOP), the lower marine riser package mandrel, or the riser flex joint. Still more particularly, the invention relates to an adapter or transition spool permitting the same containment cap to be coupled to a number of differently-configured subsea structures.

Background of the Technology

[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 annulus through the choke line or kill line to protect the well equipment disposed above the BOP and LMRP from 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 may be delivered into the well bore to kill the well.

[0006] In the event that the wellbore is not sealed, a blowout may occur. The blowout may damage subsea equipment and/or connections between subsea equipment. This can be especially problematic if it results in the discharge of hydrocarbons into the surrounding sea water. In addition, it may be challenging to rectify remotely as the discharge may be hundreds or thousands of feet below the sea surface.

[0007] In the event that a subsea blowout results in the discharge of hydrocarbons into the surrounding sea, it is important to cap and/or shut-in the well as quickly as possible in order to minimize the volume of hydrocarbons discharged. One possible approach to capping and shutting-in a subsea well is to lower a containment cap and couple it to the upper end of the equipment stack that is connected to the well bore. However, it cannot be predicted in advance where the discharge may originate within the equipment stack, how the equipment may need to be reconfigured in order to cap the well, or on which piece of the subsea equipment or structure to land the containment cap to best control the well. Furthermore, various manufacturers of BOP's, lower marine riser packages, well heads and other subsea structures have not standardized the dimensions and configurations of their products. That is, for example, the profile of a well head connector of a first manufacturer may differ from the profile of the connector provided by a second manufacturer. Likewise, as another example, the connections atop a lower marine riser package from a first manufacturer may differ in design and configuration from that of another manufacturer. A containment cap having a connector with a particular connector profile cannot couple directly to structures and equipment having non-correspondingly configured connections. It would be challenging to redesign and/or configure the capping stack connector to make it compatible with an equipment component at a subsea well from which hydrocarbons are being discharged, and such redesign or refitting of the containment cap may delay the well's containment and may allow the discharge to continue during the interim.

[0008] Accordingly, there remains a need in the art for systems and methods to cap a subsea well. Such systems and methods would be well-received if they offered the potential to cap a subsea well that is discharging hydrocarbon fluids. Particularly well-received by the industry would be a capping stack, system and method for containing subsea wells using a single containment cap having a uniform design, one capable of being deployed and coupled to differently-configured subsea components having a myriad of coupling configurations.

BRIEF SUMMARY OF THE DISCLOSURE

[0009] These and other needs in the art are addressed in one embodiment by a method for controlling hydrocarbons flowing from a subsea structure. In an embodiment, the method comprises lowering an adapter from the surface to a subsea structure. The adapter has a through bore extending between an upper connector having a first connector profile and a lower connector having a second connector profile that is different than the first connector profile. In addition, the method comprises coupling the lower connector of the adapter to the subsea structure. Further, the method comprises lowering a containment cap from the surface to the adapter. Still further, the method comprises coupling the containment cap to the upper connector of the adapter.

[0010] These and other needs in the art are addressed in another embodiment by a method of capping a subsea well. In an embodiment, the method comprises choosing from an inventory of adapters a selected adapter. The selected adapter has a lower connector with a lower connector profile configured to mate with a connector on a subsea structure and an upper connector with an upper connector profile that is different than the lower connector profile. In addition, the method comprises connecting the lower connector of the selected adapter to the subsea structure.

[0011] These and other needs in the art are addressed in another embodiment by a method of capping a subsea well. In an embodiment, the method comprises maintaining an inventory comprising a plurality of adapters. Each of the plurality of adapters having an upper connector with an upper connector profile and a lower connector with a lower connector profile that differs from the upper connector profile and that also differs from the lower connector profile of at least some of the other adapters of the plurality. In addition, the method comprises identifying the connector profile of a subsea connector on a subsea structure at a well that is discharging hydrocarbons into the surrounding sea water. Further, the method comprises selecting from the inventory a select adapter that has the lower connector with the lower connector profile that is configured to mate with the subsea connector.

[0012] These and other needs in the art are addressed in another embodiment by an adapter for coupling a containment cap to a subsea structure. In an embodiment, the adapter comprises a first portion 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 first connector having a first connector profile. In addition, the adapter comprises a second portion 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 second end comprises a second connector having a second connector profile that is different from the first connector profile.

[0013] These and other needs in the art are addressed in another embodiment by an apparatus for controlling a subsea wellbore. In an embodiment, the apparatus comprises a containment cap having a through bore and a valve adapted to close and prevent fluid flow through the through bore, and further comprising a connector at the lower end of the containment cap having a first connector profile. In addition, the apparatus comprises an adapter. The adapter includes an upper and a lower end and a through bore extending therebetween. The adapter also includes a first connector at the upper end mated to and sealingly engaged with the connector of the containment cap. Moreover, the adapter includes a second connector at the lower end adapted to mate and sealingly engage with a connector on a subsea structure other than the containment cap. The second connector of the adapter has a second connector profile that is different than the first connector profile.

[0014] Thus, embodiments described herein comprise a combination of features and advantages intended to address various shortcomings associated with certain prior devices, systems, and methods. The various features and characteristics 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.

BRIEF DESCRIPTION OF THE DRAWINGS

[0015] For a detailed description of the preferred embodiments of the invention, reference will now be made to the accompanying drawings in which:

[0016] Figure 1 is a schematic view of an embodiment of an offshore drilling system;

[0017] Figure 2 is an enlarged view of the riser flex joint of the lower marine riser package of Figure 1;

[0018] Figure 3 is a top view of the flange of the riser adapter of Figure 2;

[0019] Figure 4 is a schematic view of the offshore drilling system of Figure 1 damaged by a subsea blowout;

- [0020] Figure 5 is a perspective view of an embodiment of a modular, air-freightable containment cap for containing the wellbore of Figure 4;
- [0021] Figure 6 is a cross-sectional side view of the containment cap of Figure 5;
- [0022] Figure 7 is a perspective view of the lower assembly of Figure 5;
- [0023] Figure 8 is a side view of the lower assembly of Figure 5;
- [0024] Figure 9 is a top view of the lower assembly of Figure 5;
- [0025] Figure 10 is a schematic view of the lower assembly of Figure 5;
- [0026] Figure 11 is a perspective view of the upper assembly of Figure 5;
- [0027] Figure 12 is a side view of the upper assembly of Figure 5;
- [0028] Figure 13 is a cross-sectional side view of the upper assembly of Figure 5;
- [0029] Figure 14 is a schematic view of the upper assembly of Figure 5;
- [0030] Figure 15 is a perspective view of the kill-flowback assembly of Figure 5;
- [0031] Figure 16 is a side view of the kill-flowback assembly of Figure 5;
- [0032] Figure 17 is a perspective view of the lower assembly of Figure 5 configured for subsea deployment;
- [0033] Figure 18 is an assembly view illustrating the lower assembly of Figure 5, the running tool of Figure 17, and a pair of adapters for deploying the lower assembly subsea;
- [0034] Figure 19 is a perspective view of the upper assembly of Figure 5 configured for subsea deployment;
- [0035] Figures 20A-20L are sequential schematic views of the subsea deployment and installation of the containment cap of Figure 5 directly onto the BOP of Figure 4;
- [0036] Figure 21 is a schematic view of the containment cap of Figure 5 directly connected to the wellhead of Figure 4;
- [0037] Figure 22 is a side view of an embodiment of a transition spool for coupling the containment cap of Figure 5 to the flex joint of Figure 4;
- [0038] Figure 23 is a perspective view of an embodiment of a system for adjusting the angular orientation of the riser adapter of Figure 2;
- [0039] Figure 24 is a top view of the system of Figure 23;
- [0040] Figure 25 is a perspective view of the base members of Figure 23 mounted to the flex joint base of Figure 2;
- [0041] Figure 26 is a perspective view of an embodiment of a system for adjusting the angular orientation of the riser adapter of Figure 2;
- [0042] Figure 27 is a perspective view of the hydraulic cylinder assembly of Figure 26;

- [0043] Figure 28 is a perspective view of an embodiment of a set of wedge members for locking the angular orientation of the riser adapter of Figure 2;
- [0044] Figure 29 is a top view of the set of wedge members of Figure 28;
- [0045] Figures 30A-30P are sequential schematic views of the subsea deployment and installation of the containment cap of Figure 5 onto the flex joint of Figure of Figure 4;
- [0046] Figure 31 is a side cross-sectional view of an embodiment of a modular, air-freightable containment cap for containing the wellbore of Figure 4;
- [0047] Figure 32 is a schematic view of an embodiment of a method for deploying the containment cap of Figure 5;
- [0048] Figure 33 is a schematic view illustrating various transition spools used to couple the containment cap of Figure 5 or Figure 31 to a plurality of riser flex joints having differing connector profiles;
- [0049] Figure 34 is a front view of an embodiment of a transition spool in accordance with the principles described herein;
- [0050] Figure 35 is a perspective, exploded view of the transition spool of Figure 34;
- [0051] Figures 36A-36N are front, exploded views of embodiments of transitions spools including lower portions having different connector profiles to accommodate different landing site connector profiles;
- [0052] Figure 37 is a schematic representation of an inventory, including the modular components of the containment cap and a plurality of transition spools to couple the cap to multiple subsea components; and
- [0053] Figure 38 is a schematic representation of another inventory, including modular components of the containment cap and components of transition spools that are ready to be coupled to form completed transition spools prior to shipping.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0054] The following discussion is directed to various embodiments of the invention. Although one or more of these embodiments may be preferred, the embodiments disclosed should not be interpreted, or otherwise used, as limiting the scope of the disclosure, including the claims. In addition, one skilled in the art will understand that the following description has broad application, and the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to suggest in any way that the scope of the disclosure, including the claims, is limited to that embodiment.

[0055] 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.

[0056] 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 component couples to a second component, that connection may be through a direct engagement between the two components, or through an indirect connection via other intermediate devices, components, and/or 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 given axis, and a radial distance means a distance measured perpendicular to the given axis.

[0057] 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 mounted to BOP 120. Platform 110 is equipped with a derrick 111 that supports a hoist (not shown). A drilling riser 115 extends subsea 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 platform 110. Casing 131 extends from wellhead 130 into subterranean wellbore 101.

[0058] 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.

[0059] 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 connections 150. In general, connections 150 may comprise any suitable releasable wellhead-type mechanical connection such as the H-4® profile subsea system available from VetcoGray Inc. of Houston, Texas, the DWHC profile subsea system available from Cameron International Corporation of Houston, Texas, and the HC profile subsea system available from FMC Technologies of Houston, Texas. Typically, such wellhead-type mechanical connections (e.g., connections 150) comprise an upward-facing male connector or "hub," labeled with reference numeral 150a herein, that is received by and releasably engages a complementary, downward-facing mating female connector or receptacle, 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.

[0060] 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.

[0061] 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.

[0062] 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 a mating hub or mandrel 151 extending from the upper end 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 annular flange 118 at the lower end of riser 115 or to alternative devices. As best shown in Figure 3, flange 145a includes a plurality of circumferentially-spaced holes 147 that receive bolts for securing flange 145a to a mating annular flange 118 at the lower end of riser 115. In addition, flange 145a includes a pair of circumferentially spaced guide holes 148, each guide hole 148 having a diameter greater than the diameter of holes 147. 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.

[0063] As previously described, in this embodiment, BOP 120 includes three sets of rams (one set of shear rams 127 and two sets of pipe rams 128, 129), however, in other embodiments, the BOP (e.g., BOP 120) may include a different number of rams (e.g., four sets of rams), different types of rams (e.g., two sets of shear rams and two sets of pipe rams, one or more sets of opposed blind rams), an annular BOP (e.g., annular BOP 142a), or combinations thereof. It should be appreciated that BOP 120 is exemplary only and that any subsea BOP preferably includes at least three sets of rams including at least two sets of pipe rams and at least one set of blind-shear rams. Likewise, although LMRP 140 is shown and described as including one annular BOP 142a, in other embodiments, the LMRP (e.g., LMRP 140) may include a different number of annular BOPs (e.g., two sets of annular BOPs), different types of rams (e.g., shear rams), or combinations thereof.

[0064] Referring now to Figure 4, during a "kick" or surge of formation fluid pressure in wellbore 101, one or more rams 127, 128, 129 of BOP 120 and/or annular BOP 142a of 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 4, system 100 is shown after a subsea blowout. In the exemplary blowout scenario shown in Figure 4, riser 115 has been severed 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 hydrocarbon fluids form a subsea hydrocarbon plume 160 that extends to the sea surface 102. Embodiments of containment caps and methods for deploying same described in more detail below are designed to contain and shut-in wellbore 101, and control the subsea emission of hydrocarbon fluids to reduce and/or eliminate the subsea discharge of hydrocarbon fluids.

[0065] Referring now to Figures 5 and 6, an embodiment of a containment stack or cap 200 for capping wellbore 101 previously described (Figure 4), and containing the hydrocarbon fluids therein is shown. In this embodiment, containment cap 200 is modular, meaning cap 200 comprises distinct and separate sections or assemblies that are deployed subsea independently and then coupled together subsea to form cap 200. Specifically, containment cap 200 comprises three assemblies - a first or lower assembly 210, a second or upper assembly 250 releasably coupled to lower assembly 210 with a wellhead-type connection 150, and a kill-flowback assembly 290 releasably coupled to upper assembly 250 with a wellhead-type connection 150. As will be described in more detail below, assemblies 210, 250 function

together to contain and shut-in wellbore 101, whereas assembly 290 functions to deliver kill weight fluids to wellbore 101 and/or produce wellbore 101 once it is contained and controlled.

[0066] In this embodiment, each assembly 210, 250, 290 is sized and configured to be air-freightable on its own or in conjunction with another assembly 210, 250, 290. In other words, each assembly 210, 250, 290 has a weight and dimensions suitable for air transport. Conventional cargo aircraft such as the Antonov AN124 and Boeing 747 have a maximum payload capacity of about 120 tons (240 x 103 lbs.), and cargo bays sized to accommodate cargo having a maximum width of up to about 21 ft. and a maximum height of up to about 14 ft. In embodiments described herein, lower assembly 210 has a weight of about 70 tons (140 x 103 lbs.), upper assembly 250 has a weight of about 40 tons (80 x 103 lbs.), and kill-flowback assembly 290 has a weight of about 7.5 tons (15 x 103 lbs.). In addition, each assembly 210, 250, 290 is sized such that it can be oriented to have a width less than 21 ft. and a height less than 14 ft. For example, although upper assembly 250 may have a height greater than 14 ft., it is dimensioned such that it can be laid down and fit within the confines of the cargo bay during shipment and then erected after transport for deployment. Accordingly, any two of the three assemblies 210, 250, 290 may be transported together by air in a single cargo aircraft. The assembly 210, 250, 290 not transported with another assembly 210, 250, 290 may be transported in a separate cargo aircraft. As previously described, conventional capping stacks are not sized and configured to be transported by air because their weight exceeds the payload capacity of conventional cargo aircraft and/or their dimensions cannot be accommodated by conventional cargo aircraft cargo bays. Consequently, transport of such conventional capping stacks must be accomplished by land and/or sea vessel, which, depending on the relative locations of the offshore blowout and the capping stack, may be time consuming. For example, if there is a subsea blowout in the Gulf of Mexico, and the most suitable capping stack for containing that blowout is located in the Middle East, it may take days or even weeks to transport the capping stack by land and sea to the offshore location in the Gulf of Mexico. However, embodiments of containment caps described herein (e.g., cap 200) are air-freightable, and thus, may be transported around the globe in a matter of hours or short number of days (e.g., one to two days maximum). As a result, embodiments described herein offer the potential to more efficiently and timely contain a subsea blowout, thereby reducing the total volume of subsea hydrocarbon emissions.

[0067] Referring now to Figures 5-10, lower assembly 210 includes a frame 211 and a spool tree or body 221 disposed within frame 211. Frame 211 supports spool body 221 and the other

components of lower assembly 210. In addition, frame 211 protects spool body 221 and the other components of lower assembly 210 from impacts during transport and deployment.

[0068] Spool body 221 includes a first pipe spool or spool piece 222 and a second pipe spool or spool piece 230 attached to and extending perpendicularly from spool piece 222. Spool piece 222 has a central or longitudinal axis 223, a first or upper end 222a, a second or lower end 222b opposite end 222a, a vertical flow bore or throughbore 224 extending axially between ends 222a, b, and a horizontal flow bore 225 extending perpendicularly from bore 224. Upper end 222a of first spool piece 222 defines the upper end of spool body 221, and lower end 222b of first spool piece 222 defines the lower end of spool body 221. Throughbore 224 is coaxially disposed within spool piece 222. In other words, throughbore 224 has a central axis coincident with axis 223. Throughbore 224 has a minimum inner diameter equal to or greater than the inner diameter of wellbore 101, through bore 142, and main bore 124, and thus, throughbore 224 may be described as having a "full bore diameter" and providing "full bore access."

[0069] Upper end 222a of spool piece 222 comprises an upward-facing hub 150a and lower end 222b comprises a downward-facing receptacle 150b. Hub 150a at upper end 222a extends axially upward from frame 211 and is configured to mate, engage, and interlock with a downward-facing complementary connector 150b on upper assembly 250, thereby forming a releasable wellhead-type, hydraulically actuated mechanical connection 150 between assemblies 210, 250. As will be described in more detail below, receptacle 150b at lower end 222b is configured to mate, engage, and interlock with an upward-facing complementary hub 150a on a transition spool 330, BOP 120, or wellhead 130, thereby forming a releasable wellhead-type, hydraulically actuated mechanical connection 150 between lower assembly 210 and flex joint adapter 145, BOP 120, or wellhead 130, respectively.

[0070] Referring still to Figures 6-10, second spool piece 230 extends perpendicularly from first spool piece 222 and has a central or longitudinal axis 231, a first or radially inner end 230a (relative to axis 223) secured to spool piece 222, a second or radially outer end 230b (relative to axis 223) opposite end 230a and distal spool piece 222, and a horizontal flow bore or throughbore 232 extending axially (relative to axis 231) between ends 230a, b. Throughbore 232 is coaxially disposed within spool piece 230, and thus, throughbore 232 has a central axis coincident with axis 231.

[0071] Throughbore 232 is coaxially aligned with and contiguous with horizontal bore 225. Thus, throughbore 232 is in fluid communication with bore 225. Together, bores 225, 232 define a horizontal branch or flow path in spool body 221 that extends perpendicularly from vertical main bore 224. As best shown in Figure 10, first spool piece 222 includes a valve 233

positioned along bore 225 and second spool piece 230 includes a valve 233 positioned along throughbore 232. Valves 233 control the flow of fluids through bores 225, 232. Namely, each valve 233 has an open position allowing fluid flow therethrough and a closed position restricting and/or preventing fluid flow therethrough. Valves 233 are positioned in series along bores 225, 232. Consequently, fluid flow through bores 225, 232 is restricted and/or prevented if one or both valves 233 are closed, and fluid flow through bores 225, 232 is permitted if both valves 233 are opened. In general, each valve 233 may comprise any type of valve suitable for the anticipated fluid pressures and fluids in bore 232 including, without limitation, ball valves, gate valves, and butterfly valves. Further, each valve 233 may be manually actuated, hydraulically actuated, mechanically actuated, or electrically actuated valves. In this embodiment, each valve 233 is a hydraulically actuated gate valve rated for a 15k psi pressure differential. Each valve 233 may be controlled and hydraulically actuated subsea with an ROV. Alternatively, each valve 233 may be controlled from the surface with hydraulic flow lines or flying leads extending from the surface and coupled to valves 233 via a panel located on lower assembly 210.

[0072] Lower assembly 210 also includes a choke valve 234 positioned between a fluid conduit 235 and spool piece 230. Fluid conduit 235 has a first end 235a coupled to choke valve 234, a second end 235b distal choke valve 234, and a flow bore 236 extending between ends 235a, b. Ends 230b, 235a are coupled to choke valve 234, and bores 232, 236 are in fluid communication with choke valve 234. Thus, choke valve 234 controls the flow rate of fluids between bores 232, 236. In general, choke valve 234 may comprise any suitable choke or choke valve for regulating the rate of fluid flow between bores 232, 236. In this embodiment, choke valve 234 is a Willis CC40 Control Choke with SLCA Hydraulic Stepping Actuator capability (non-functional) or mechanical stepping capability with torque tool available from Cameron International Corporation of Houston, Texas. The choke valve 234 has a retrievable insert that can be removed and replaced subsea.

[0073] Second end 235b of fluid conduit 235 comprises an upward-facing hub 239a configured to mate, engage, and interlock with a downward-facing connector of a flow line to form a releasable flow line connection therebetween. Thus, with each valve 233 open, fluid in throughbore 224 is free to flow through bores 225, 232, choke valve 234, and bore 236 to hub 239a at end 235b, where the fluid may be discharged into the surrounding sea or flowed into another device connected to hub 239a at end 235b. For example, as will be described in more detail below, when lower assembly 210 is coupled to wellbore 101 and each valve 233 is open, hydrocarbons discharged from wellbore 101 may be flowed from bore 224 through bores 225,

232, choke valve 234, and bore 236 to hub 239a at end 235b, where the hydrocarbons may be discharged into the surrounding sea or produced to another device connected to hub 239a at end 235b. Alternatively, with each valve 233 open, fluid may be supplied and/or pumped from a device connected to hub 239a through bore 236, choke valve 234, and bores 232, 225 into bore 224. For example, as will be described in more detail below, when lower assembly 210 is coupled to wellbore 101, chemicals or kill weight fluids may be supplied and/or pumped from a device connected to hub 239a through bore 236, choke valve 234, and bores 232, 225 into hydrocarbons in bore 224.

[0074] As best shown in Figure 10, a first annulus line 237 and a second annulus line 238 provide access to throughbore 224 axially above and below bore 225, respectively. In particular, first annulus line 237 has a first or radially inner end 237a in fluid communication with throughbore 224 and a second or radially outer end 237b extending to the outer surface of spool piece 222; and second annulus line 238 has a first or radially inner end 238a in fluid communication with throughbore 224 and a second or radially outer end 238b extending to the outer surface of spool piece 222. End 237a is positioned axially above bore 225, and end 238a is positioned axially below bore 225. Ends 237b, 238b may be accessed by an ROV or other device as desired. In this embodiment, one valve 233 as previously described is positioned along each flow line 237, 238 between ends 237a, b and 238a, b, respectively. Lines 237, 238 may be employed to produce wellbore 101 once it has been contained and controlled.

[0075] Referring still to Figure 10, in this embodiment, lower assembly 210 also includes a chemical injection system 240 and a fluid monitoring or sensor system 226. For purposes of clarity, chemical injection system 240 and fluid monitoring system 226 are not shown in Figures 6-9. Chemical injection system 240 includes a first flow line 241 for injecting chemicals into bore 232, a second flow line 242 for injecting chemicals into bore 224 above bore 225, and a third flow line 243 for injecting chemicals into bore 224 above second flow line 242. The upstream ends of flow lines 241, 242, 243 converge at a common inlet port of a dual port ROV hot stab receptacle 248. Chemicals such as methanol and glycol may be supplied and/or pumped through flow lines 241, 242, 243 via inlet receptacle 248.

[0076] Each flow line 241, 242, 243 includes a primary valve 245 for controlling the flow of chemicals through that particular flow line 241, 242, 243. Namely, each valve 245 has an open position allowing fluid flow therethrough and a closed position restricting and/or preventing fluid flow therethrough. Consequently, fluid flow through a particular flow line 241, 242, 243 is restricted and/or prevented if its corresponding valve 245 is closed, and fluid flow through a particular flow line 241, 242, 243 is permitted if its corresponding valve 245 is opened. In

general, each valve 245 may comprise any type of valve suitable for the anticipated fluid pressures and fluids in flow lines 241, 242, 243 including, without limitation, ball valves, gate valves, and butterfly valves. Further, each valve 245 may be manually actuated, hydraulically actuated, mechanically actuated, or electrically actuated valves. In this embodiment, each valve 245 is a hydraulically actuated gate valve rated for a 15k psi pressure differential. Each valve 245 may be controlled and hydraulically actuated subsea with an ROV. In addition, in this embodiment, valve 245 on each flow line 242, 243 includes a check valve that allows one-way fluid communication from inlet receptacle 248 to bore 224. Valve 245 on flow line 241 does not include a check valve so that pressure testing and sampling of bore 232 may be performed. Each flow line 242, 243 also includes a pressure gauge 246 positioned between valve 245 and its inlet receptacle 248. Gauges 246 measure the fluid pressure within flow lines 242, 243. Secondary valves 247 are positioned along flow lines 242, 243 between gauges 246 and inlet receptacle 248, and an additional secondary valve 247 is positioned at inlet receptacle 248. Secondary valves 247 provide a secondary means to valves 245 for controlling fluid flow through flow lines 241, 242, 243. In general, each valve 247 may comprise any type of valve suitable for the anticipated fluid pressures and fluids in flow lines 241, 242, 243 including, without limitation, ball valves, gate valves, and butterfly valves. Further, each valve 247 may be manually actuated, hydraulically actuated, mechanically actuated, or electrically actuated valves. In this embodiment, each valve 247 is a manually operated needle valve rated for a 15k psi pressure differential. Each valve 247 may be manually operated subsea with an ROV. Alternatively, each valve 247 may be hydraulically controlled from the surface with hydraulic flow lines or flying leads extending from the surface and coupled to valves 247 via a panel located on lower assembly 210.

[0077] Referring still to Figure 10, fluid monitoring system 226 includes an electronic pressure transducer 227 positioned along throughbore 224 and an electronic temperature transducer 228 positioned along throughbore 224. Transducers 227, 228 measure and monitor the pressure and temperature, respectively, of fluids in bore 224. Each transducers 227, 228 is electronically coupled to an electrical coupling 229 configured to transmit the measured temperature and pressure data, respectively, from transducers 227, 228, respectively, to a subsea ROV or other device connected to coupling 229.

[0078] Referring now to Figures 5, 6, and 11-14, upper assembly 250 includes a frame 251 and a pipe spool or spool piece 260 disposed within frame 251. Frame 251 supports spool piece 260 as well as the remaining components of upper assembly 250. In addition, frame 251 protects spool piece 260 and the remaining components of upper assembly 250 from impacts

during transport and deployment. The top of frame 251 comprises a planar pad 252 for landing kill-flowback assembly 290.

[0079] Spool piece 260 has a central or longitudinal axis 261, a first or upper end 260a, a second or lower end 260b opposite end 260a, and a flow bore or throughbore 262 extending axially between ends 260a, b. Flow bore 262 is coaxially disposed within spool piece 260. In other words, flow bore 262 has a central axis coincident with axis 261. In this embodiment, spool piece 260 is oriented such that axis 261 and flow bore 262 extend vertically. In addition, in this embodiment, flow bore 262 has a minimum inner diameter that is less than the minimum inner diameter of throughbore 224 and wellbore 101.

[0080] Upper end 260a of spool piece 260 comprises an upward-facing hub 150a and lower end 260b comprises a downward-facing receptacle 150b. Hub 150a at upper end 260a extends axially upward from pad 252 and is configured to mate, engage, and interlock with a complementary downward-facing connector 150b on assembly 290, thereby forming a releasable wellhead-type, hydraulically actuated mechanical connection 150 between assemblies 250, 290. Further, receptacle 150b at lower end 260b is configured to mate, engage, and interlock with a complementary upward-facing hub 150a at upper end 222a of spool piece 221, thereby forming a releasable wellhead-type, hydraulically actuated mechanical connection 150 between assemblies 210, 250.

[0081] As best shown in Figures 12-14, spool piece 260 also includes a first or lower valve 263, a second or upper valve 263, and a flow bore access member 265, each positioned along flow bore 262 between ends 260a, b. More specifically, second valve 263 is axially spaced above first valve 263, and access member 265 is axially positioned between valves 263. Valves 263 control the flow of fluids in bore 262. Namely, each valve 263 has an open position allowing fluid flow therethrough and a closed position restricting and/or preventing fluid flow therethrough. Valves 263 are positioned in series along flow bore 262. Consequently, fluid flow through bore 262 is restricted and/or prevented if one or both valves 263 are closed, and fluid flow through bore 262 is permitted if both valves 263 are opened. In general, each valve 263 may comprise any type of valve suitable for the anticipated fluid pressures and fluids in bore 262 including, without limitation, ball valves, gate valves, and butterfly valves. Further, each valve 263 may be manually actuated, hydraulically actuated, mechanically actuated, or electrically actuated valves. In this embodiment, each valve 263 is a hydraulically actuated gate valve rated for a 15k psi pressure differential. Each valve 263 may be controlled and hydraulically actuated subsea with an ROV. As will be described in more detail below, flow bore access member 265 enables access to flow bore 262.

[0082] Referring now to Figure 14, in this embodiment, upper assembly 250 also includes a chemical injection system 270 and a fluid monitoring or sensor system 280. For purposes of clarity, chemical injection system 270 and fluid monitoring system 280 are not shown in Figures 5, 6, and 11-13. Chemical injection system 270 includes a supply line 271 that may be used to inject chemicals into bore 262 and a return line 272 for receiving fluids from bore 262. Supply line 271 has an inlet end 271a and a second or outlet end 271b in fluid communication with bore 262 via access member 265. Return line 272 has a first or inlet end 272a in fluid communication with bore 262 via access member 265 and a second or outlet end 272b. Inlet end 271a and outlet end 272b are connected to separate ports on a dual port ROV hot stab receptacle 248. Chemicals such as methanol and glycol may be supplied and/or pumped through supply line 271 into bore 262, and fluids in bore 262 may be acquired via return line 272. As will be described in more detail below, supply and return lines 271, 272 may also be used to acquire wellbore fluid samples for pressure and/or temperature measurement and monitoring.

[0083] Each flow line 271, 272 includes a pair of valves 273, arranged series, for controlling the flow of chemicals through that particular flow line 271, 272. Namely, each valve 273 has an open position allowing fluid flow therethrough and a closed position restricting and/or preventing fluid flow therethrough. Consequently, fluid flow through a particular flow line 271, 272 is restricted and/or prevented if one or both of its valves 273 is closed, and fluid flow through a particular flow line 271, 272 is permitted if both of its corresponding valves 273 are opened. In general, each valve 273 may comprise any type of valve suitable for the anticipated fluid pressures and fluids in flow lines 271, 272 including, without limitation, ball valves, gate valves, and butterfly valves. Further, each valve 273 may be manually actuated, hydraulically actuated, mechanically actuated, or electrically actuated valves. In this embodiment, each valve 273 is a manually operated needle valve rated for a 15k psi differential. Each valve 273 may be manually operated subsea with an ROV. In this embodiment, return line 272 includes a pressure gauge 246 positioned between valves 273 and access member 265. Gauge 246 measure the fluid pressure within return line 272.

[0084] Referring still to Figure 14, fluid monitoring system 280 includes a bore fluid supply line 281, a bore fluid return line 282, and a sensor package or assembly 285. Flow line 281 has an inlet end 281a in fluid communication with flow bore 262 via access member 265 and an outlet end 281b comprising a coupling 283. Flow line 282 has an inlet end 282a comprising a coupling 283 and an outlet end 282b in fluid communication with flow bore 262 via access member 265. Each flow line 281, 282 includes a valve 247 as previously described for

controlling the flow of fluids through that particular flow line 281, 282. Sensor package 285 includes a fluid flow line 286, a pressure sensor 287 disposed along line 286, a temperature sensor 288 disposed along line 286, and a data transmitter 289 coupled to sensors 287, 288. Flow line 286 has an inlet end 286a comprising a coupling 284 releasably coupled to coupling 283 of line 281 and an outlet end 286b comprising a coupling 284 releasably coupled to coupling 283 of line 282. Thus, flow lines 281, 282, 286 create a bore fluid flow loop - fluids in flow bore 262 flow through line 281, 286, and 282 back into flow bore 262. Sensors 287, 288 measure the pressure and temperature, respectively, of the bore fluids flowing through flow line 286. The measured pressure and temperature data is communicated to transmitter 289, which then wirelessly retransmits the measured pressure and temperature data to the surface. Transmitter 289 may communicate pressure and temperature data periodically or on a real-time basis. In general, transmitter 289 may be any suitable device for transmitting data from a subsea location to the surface. In this embodiment, transmitter 289 is an acoustic datalogger. As described above, sensor package 285 is releasably coupled to lines 281, 282 via couplings 283, 284. Thus, sensor package 285 may be removed or coupled to access member 265 as desired. One or more ROVs may be used to connect sensor package 285 to lines 281, 282 and to disconnect sensor package 285 from lines 281, 282.

[0085] In this embodiment, systems 270, 280 utilize separate supply and return lines. Namely, system 270 includes supply line 271 and return line 272, and system 280 includes supply line 281 and return line 282. However, in other embodiments, the fluid monitoring system (e.g., system 280) may utilize the same supply and return lines as the chemical injection system (e.g., system 270). For example, sensor package 285 may be configured to plug into hot stab receptacle 248, receive wellbore fluids via supply line 271 and return wellbore fluids via return line 272. In other words, ends 286a, b of flow line 286 may be configured as ports in a hot stab connector that is coupled to receptacle 248 with inlet end 286a in fluid communication with supply line 271 and outlet end 286b in fluid communication with return line 272.

[0086] Referring now to Figures 5, 6, 15 and 16, kill-flowback assembly 290 includes a frame 291 and a pipe spool or spool piece 292 extending through frame 291. Frame 291 supports spool piece 292 as well as the remaining components of assembly 290. In addition, frame 291 protects spool piece 292 and the remaining components of assembly 290 from impacts. The lower end of frame 291 comprises an annular funnel or guide 293 to facilitate the landing of assembly 290 onto upper assembly 250.

[0087] Spool piece 292 has a central or longitudinal axis 294, a first or upper end 292a, a second or lower end 292b opposite end 292a, and a flow bore or throughbore 295 extending

axially between ends 292a, b. Flow bore 295 is coaxially disposed within spool piece 292. In other words, flow bore 295 has a central axis coincident with axis 294. In this embodiment, spool piece 292 is oriented such that axis 294 and flow bore 295 extend vertically. In this embodiment, flow bore 295 has an inner diameter that is the same as the inner diameter of flow bore 262.

[0088] Upper end 292a of spool piece 292 extends axially upward from frame 291 and comprises an upward-facing flange 296, and lower end 292b comprises a downward-facing receptacle 150b. Flange 296 is configured to mate, engage, and connect with a downward-facing flange on a flow conduit that supplies kill weight fluids to cap 200 and/or produces hydrocarbons from wellbore 101. In this embodiment, two exemplary conduits 298, 299 are shown in Figures 15 and 16. Receptacle 150b at lower end 292b is configured to mate, engage, and interlock with upward-facing hub 150a at upper end 260a of spool piece 260, thereby forming a releasable wellhead-type, hydraulically actuated mechanical connection 150 between assemblies 250, 290.

[0089] Referring again to Figure 6, upper assembly 250 is releasably coupled to lower assembly 210 with a wellhead-type connection 150, and kill-flowback assembly 290 is releasably coupled to upper assembly with a wellhead-type connection 150. When cap 200 is assembled as shown in Figure 6, flow bores 224, 262, 295 are coaxially aligned, flow bore 224 is in fluid communication with flow bore 262, and flow bore 295 is in fluid communication with flow bores 224, 262 as long as both valves 263 in flow bore 262 are opened. Thus, with valves 263 opened, fluids are free to flow through bores 224, 262, 295 between ends 222b, 292a. Thus, when cap 200 is coupled to subsea wellhead 130, BOP 120, or LMRP 140, valves 263 are opened, and full access bore 224 is in fluid communication with wellbore 101, kill weight fluids may be pumped into wellbore 101 via conduit 298 or 299 during kill operations, or alternatively, hydrocarbons flowing from wellbore 101 may be produced via conduit 298 or 299.

[0090] In this embodiment, containment cap 200 is designed to be deployed subsea and landed on riser flex joint 143 of LMRP 140, on mandrel 151 of LMRP 140, on BOP 120, or on wellhead 130, depending on which is the most suitable landing site. For example, in Figure 20L, cap 200 is shown installed on subsea BOP 120 previously described; in Figure 21, cap 200 is shown installed on subsea wellhead 130 previously described; and in Figure 30P, cap 200 is shown installed on flex joint 143 of LMRP 140 previously described. Regardless of the landing/installation site, in this embodiment, the modular cap 200 previously described is installed in stages - lower assembly 210 is first deployed subsea and installed on the selected

landing site (e.g., LMRP 140, mandrel 151, flex joint 143, wellhead 130, BOP 120), then upper assembly 250 is deployed subsea and installed onto lower assembly 210, and then kill-flowback assembly 290 is deployed subsea and installed onto upper assembly 250.

[0091] Referring briefly to Figures 17 and 18, in this embodiment, lower assembly 210 is lowered and manipulated subsea with a running tool 215 releasably coupled to hub 150a at upper end 222a of spool piece 222. As best shown in Figure 18, running tool 215 has a first or upper end 215a and a second or lower end 215b opposite end 215a. Lower end 215b comprises a downward-facing receptacle 150b that releasably engages hub 150a at upper end 222a. Upper end 215a of running tool 215 may be releasably coupled to a first adapter 216 that enables deployment of lower assembly 210 with a pipestring or drillstring, or to a second adapter 217 that enables deployment of lower assembly 210 on wireline. Thus, running tool 215 may be deployed subsea from a surface vessel with a pipe string using first adapter 216 and running tool 215, or with a wireline using second adapter 217 and running tool 215. As shown in Figure 19, upper assembly 250 is lowered and manipulated subsea with wireline coupled to frame 251 with a plurality of lead lines 253 disposed about pad 252. Kill-flowback assembly 290 is lower and manipulated subsea with wireline in the same manner as upper assembly 250. In other embodiments, upper assembly 250 and/or kill-flowback assembly 290 may be lowered via drillpipe, tubing string, flexible tubing, or coiled tubing.

[0092] Referring now to Figures 20A-20L, containment cap 200 is shown being deployed and installed subsea on BOP 120 to shut-in and/or produce wellbore 101. More specifically, in Figures 20A-20D, lower assembly 210 is shown being lowered subsea and coupled to BOP 120; in Figures 20E-20H, upper assembly 250 is shown being lowered subsea and coupled to lower assembly 210; and in Figures 20I-20L, kill-flowback assembly 290 is shown being lowered subsea and coupled to upper assembly 250.

[0093] For subsea deployment and installation of containment cap 200, one or more remote operated vehicles (ROVs) are preferably employed to aid in positioning assemblies 210, 250, 290, monitoring assemblies 210, 250, 290 and BOP 120, and operating assemblies 210, 250, 290 (e.g., actuating valves 233, 263, operating chemical injection systems, etc.). In this embodiment, three ROVs 170 are employed to position assemblies 210, 250, 290, monitor assemblies 210, 250, 290 and BOP 120, and operate assemblies 210, 250, 290. Each ROV 170 includes an arm 171 having a claw 172, a subsea camera 173 for viewing the subsea operations (e.g., the relative positions of assemblies 210, 250, 290, BOP 120, plume 160, the positions and movement of arms 170 and claws 172, 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 claws 172 are controlled via commands sent from the surface or other remote location to ROV 170 through umbilical 174.

[0094] Before connecting cap 200 to BOP 120, LMRP 140 is removed from BOP 120 by decoupling connection 150 between BOP 120 and LMRP 140, and then lifting LMRP 140 from BOP 120 with wireline, a pipestring, one or more ROVs 170, or combinations thereof. In addition, any tubulars or debris extending from upper end 123a of BOP 120 are cut off substantially flush with upper end 123a with one or more ROVs 170.

[0095] Referring first to Figure 20A, in this embodiment, lower assembly 210 is shown being controllably lowered subsea with a pipestring 180 secured to the upper end of adapter 216 and extending to a surface vessel. A derrick or other suitable device mounted to the surface vessel is preferably employed to support and lower assembly 210 on string 180. Although string 180 is employed to deploy lower assembly 210 in this embodiment, in other embodiments, lower assembly 210 may be deployed subsea on wireline. Using string 180, lower assembly 210 is lowered subsea under its own weight from a location generally above and laterally offset from wellbore 101 and BOP 120. More specifically, during deployment, lower assembly 210 is preferably maintained outside of plume 160 of hydrocarbon fluids emitted from wellbore 101. Lowering lower assembly 210 subsea in plume 160 may trigger the undesirable formation of hydrates within lower assembly 210, particularly at elevations substantially above sea floor 103 where the temperature of hydrocarbons in plume 160 is relatively low.

[0096] Moving now to Figure 20B, lower assembly 210 is lowered laterally offset from BOP 120 and outside of plume 160 until lower end 222b is slightly above BOP 120. As assembly 210 descends and approaches BOP 120, ROVs 170 monitor the position of assembly 210 relative to BOP 120. Next, as shown in Figure 20C, assembly 210 is moved laterally into position immediately above and substantially coaxially aligned with BOP 120. One or more ROVs 170 may utilize their claws 172 and frame 211 to guide and manipulate the position of assembly 210 relative to BOP 120. Due to its own weight, assembly 210 is substantially vertical, whereas BOP 120 may be oriented at a slight angle relative to vertical. Thus, it is to be understood that perfect coaxial alignment of BOP 120 and assembly 210 may be difficult. However, the mating profiles of hub 150a at upper end 123a of BOP 120 and receptacle 150b at lower end 222b of assembly 210 facilitate the coaxial alignment and coupling of assembly 210 and BOP 120 as assembly 210 is lowered from a position immediately above BOP 120, even if assembly 210 is initially slightly misaligned with BOP 120.

[0097] Moving now to Figure 20D, with receptacle 150b at lower end 222b of assembly 210 positioned immediately above and substantially coaxially aligned with hub 150a at upper end 123a of BOP 120, string 180 lowers assembly 210 axially downward. Due to the weight of assembly 210, compressive loads between assembly 210 and BOP 120 urge the male hub 150a at upper end 123a into the female receptacle 150b at lower end 222b. Once the hub 150a is sufficiently seated in the receptacle 150b to form wellhead-type connection 150, connection 150 is hydraulically actuated to securely connect assembly 210 to BOP 120 as shown in Figure 20D.

[0098] As assembly 210 is positioned immediately above BOP 120, hydrocarbons emitted from BOP 120 are free to flow unrestricted through bore 224. In addition, prior to moving assembly 210 laterally over BOP 120, valves 233 in lines 237, 238 are closed, and valves 233 in bores 225, 232 are opened to allow hydrocarbon fluids emitted by BOP 120 to flow through bore 232, choke 234, and bore 236. Valves 233 in bores 225, 232 may be transitioned to the open position and valves 233 in lines 237, 238 may be transitioned to the closed position at the surface 102 prior to deployment, or subsea via one or more ROVs 170. Thus, as assembly 210 is moved laterally over BOP 120 and lowered into engagement with BOP 120, emitted hydrocarbon fluids flow freely through bores 224, 225, 232, 236. As a result, open valves 233 offer the potential to reduce the resistance to the axial insertion of hub 150a into receptacle 150b and coupling of lower assembly 210 to BOP 120. In other words, open valves 233 in bores 225, 232 allow the relief of well pressure during installation of lower assembly 210. With a sealed, secure connection between lower assembly 210 and BOP 120, ROVs 170 decouple running tool 215 from lower assembly 210. Running tool 215 and adapter 216 may then be removed to the surface with pipestring 180.

[0099] Referring now to Figure 20E, with lower assembly 210 securely coupled to BOP 120, upper assembly 250 is deployed and coupled to lower assembly 210. In this embodiment, upper assembly 250 is shown being controllably lowered subsea with wireline 181 extending from a surface vessel and having a lower end secured to leads 253. Due to the weight of assembly 250, wireline 181 and leads 253 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 is preferably employed to support and lower assembly 250 on wireline 181. Although wireline 181 and leads 253 are employed to lower assembly 250 in this embodiment, in other embodiments, assembly 250 may be deployed subsea on a pipe string. Using wireline 181, assembly 250 is lowered subsea under its own weight from a location generally above and

laterally offset from wellbore 101, BOP 120, lower assembly 210, and outside of plume 160 to reduce the potential for hydrate formation within assembly 250.

[00100] Moving now to Figure 20F, upper assembly 250 is lowered laterally offset from lower assembly 210 and outside of plume 160 until lower end 260b is slightly above lower assembly 210. As upper assembly 250 descends and approaches lower assembly 210, ROVs 170 monitor the position of upper assembly 250 relative to lower assembly 210. Next, as shown in Figure 20G, assembly 250 is moved laterally into position immediately above and substantially coaxially aligned with lower assembly 210. One or more ROVs 170 may utilize their claws 172 and frame 251 to guide and manipulate the position of upper assembly 250 relative to lower assembly 210. Due to its own weight, assembly 250 is substantially vertical, whereas lower assembly 210 may be oriented at a slight angle relative to vertical if BOP 120 was slightly angled. Thus, it is to be understood that perfect coaxial alignment of assemblies 210, 250 may be difficult. However, the mating profiles of hub 150a at upper end 222a of spool piece 222 and receptacle 150b at lower end 260b of assembly 250 facilitate the coaxial alignment and coupling of assemblies 210, 250 as upper assembly 250 is lowered from a position immediately above lower assembly 210, even if upper assembly 250 is initially slightly misaligned with lower assembly 210.

[00101] Moving now to Figure 20H, with receptacle 150b at lower end 260b positioned immediately above and substantially coaxially aligned with hub 150a at upper end 222a, wireline 181 lowers assembly 250 axially downward. Due to the weight of assembly 250, compressive loads between upper assembly 250 and lower assembly 210 urge the male hub 150a at upper end 222a into the female receptacle 150b at lower end 260b. Once the hub 150a is sufficiently seated in the receptacle 150b to form wellhead-type connection 150, connection 150 is hydraulically actuated to securely connect upper assembly 250 to lower assembly 210 as shown in Figure 20H. With a sealed, secure connection between lower assembly 210 and upper assembly 250, ROVs 170 decouple leads 253 from upper assembly 250. Leads 253 may then be removed to the surface with wireline 181.

[00102] Prior to moving upper assembly 250 laterally over lower assembly 210 and BOP 120, valves 263 are transitioned to the open position also allowing hydrocarbon fluids emitted by BOP 120 and lower assembly 210 to flow through bore 262. Valves 263 may be transitioned to the open position at the surface 102 prior to deployment, or subsea via one or more ROVs 170. Thus, as upper assembly 250 is moved laterally over lower assembly 210 and lowered into engagement with lower assembly 210, emitted hydrocarbon fluids flow freely through bore 262. As a result, open valves 263 offer the potential to reduce the resistance to the axial

insertion of hub 150a into receptacle 150b and coupling of upper assembly 250 to lower assembly 210. In other words, open valves 263 allow the relief of well pressure during installation of upper assembly 250. It should also be appreciated that aligned bores 224, 262 enable re-entry of BOP 120 and wellbore 101.

[00103] Referring now to Figure 20I, with upper assembly 250 securely coupled to lower assembly 210, kill-flowback assembly 290 is deployed and coupled to upper assembly 250. Assembly 290 is deployed in substantially the same manner as upper assembly 250. Specifically, in this embodiment, kill-flowback assembly 290 is shown being controllably lowered subsea with wireline 181 extending from a surface vessel and having a lower end coupled to frame 291 with a plurality of leads 253. Due to the weight of assembly 290, wireline 181 and leads 253 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 is preferably employed to support and lower assembly 290 on wireline 181. Although wireline 181 and leads 253 are employed to lower assembly 290 in this embodiment, in other embodiments, assembly 290 may be deployed subsea on a pipe string. Using wireline 181, assembly 290 is lowered subsea under its own weight from a location generally above and laterally offset from wellbore 101, BOP 120, lower assembly 210, upper assembly 250, and outside of plume 160 to reduce the potential for hydrate formation within assembly 290.

[00104] Moving now to Figure 20J, assembly 290 is lowered laterally offset from upper assembly 250 and outside of plume 160 until lower end 292b is slightly above upper assembly 250. As assembly 290 descends and approaches upper assembly 250, ROVs 170 monitor the position of assembly 290 relative to upper assembly 250. Next, as shown in Figure 20K, assembly 290 is moved laterally into position immediately above and substantially coaxially aligned with upper assembly 250. One or more ROVs 170 may utilize their claws 172 and frame 291 to guide and manipulate the position of assembly 290 relative to upper assembly 250. Due to its own weight, assembly 290 is substantially vertical, whereas upper assembly 250 may be oriented at a slight angle relative to vertical if BOP 120 was slightly angled. Thus, it is to be understood that perfect coaxial alignment of assemblies 250, 290 may be difficult. However, the mating profiles of hub 150a at upper end 260a of spool piece 260 and receptacle 150b at lower end 292b of spool piece 292 facilitate the coaxial alignment and coupling of assemblies 250, 290 as assembly 290 is lowered from a position immediately above upper assembly 250, even if assembly 290 is initially slightly misaligned with upper assembly 250.

[00105] Moving now to Figure 20L, with receptacle 150b at lower end 292b positioned immediately above and substantially coaxially aligned with hub 150a at upper end 260a,

wireline 181 lowers assembly 290 axially downward. Due to the weight of assembly 290, compressive loads between assembly 290 and upper assembly 260 urge the male hub 150a at upper end 260a into the female receptacle 150b at lower end 292b. Once the hub 150a is sufficiently seated in the receptacle 150b to form wellhead-type connection 150, connection 150 is hydraulically actuated to securely connect kill-flowback assembly 290 to upper assembly 250 as shown in Figure 20L. With a sealed, secure connection between upper assembly 250 and kill-flowback assembly 290 ROVs 170 decouple leads 253 from assembly 290. Leads 253 may then be removed to the surface with wireline 181.

[00106] Prior to moving assembly 290 laterally over upper assembly 250 and BOP 120, flow bore 295 is maintained opened to allow hydrocarbon fluids emitted by BOP 120 and assemblies 210, 250 to flow through bore 295. Thus, as kill-flowback assembly 290 is moved laterally over upper assembly 250 and lowered into engagement with upper assembly 250, emitted hydrocarbon fluids flow freely through bore 295, thereby offering the potential to reduce the resistance to the axial insertion of hub 150a into receptacle 150b and coupling of assembly 290 to upper assembly 250. In other words, open flow bore 295 allows the relief of well pressure during installation of kill-flowback assembly 290. A conduit 298, 299 may be coupled to upper end 292a of spool piece 292 (to supply kill weight fluids or produce wellbore 101) once assembly 290 is securely connected to upper assembly 250.

[00107] In the manner described, cap 200 is deployed and installed on BOP 120. However, as best shown in Figure 21, cap 200 may also be installed directly onto wellhead 130. Assemblies 210, 250, 290 are deployed subsea and connected together in the exact same manner as previously described with the exception that lower assembly 210 is securely connected to wellhead 130. In particular, downward-facing receptacle 150b at lower end 222b is coupled to upward-facing receptacle 150a of wellhead 130, thereby forming connection 150 between lower assembly 210 and wellhead 130. Before connecting lower assembly 210 to wellhead 130, LMRP 140 and BOP 120 are removed from wellhead 130 by decoupling connection 150 between BOP 120 and LMRP 140, lifting LMRP 140 from BOP 120 and then decoupling connection 150 between BOP 120 and wellhead 130 and lifting BOP 120 from wellhead 130. In addition, any tubulars or debris extending from wellhead 130 are cut off substantially flush with the upper end of wellhead hub 150a with one or more ROVs 170.

[00108] Referring now to Figures 6 and 20L, upon installation of containment cap 200, hydrocarbons are free to flow through cap 200. To contain and shut-in wellbore 101, valves 233 in bores 225, 232 and valves 263 in bore 262 are manipulated by subsea ROVs 170. If kill fluids are utilized to aid in shutting in wellbore 101, kill-flowback assembly 290 is preferably

installed prior to initiating the shut-in procedures (i.e., so that kill weight fluids may be supplied to cap 200 and wellbore 101 via conduit 298). However, if kill fluids are not utilized to aid in shutting in wellbore 101, the shut-in procedures may be initiated prior to installation of kill-flowback assembly 290.

[00109] To shut-in wellbore 101, valves 233 in flow lines 237, 238 are both closed, and valves 233 in bores 225, 232 are both maintained opened while upper valve 263 is transitioned closed. As upper valve 263 is transitioned closed, the pressure of wellbore fluids within lower assembly 210 are monitored with pressure transducer 227 and the pressure of wellbore fluids within upper assembly 250 are monitored with pressure sensor 287. As long as the formation fluid pressures within assemblies 210, 250 are within acceptable limits, upper valve 263 continues to be closed until it is fully closed. Once upper valve 263 is closed, lower valve 263 may also be fully closed to provide redundancy. With both valves 263 closed, fluid flow through bore 262 is restricted and/or prevented, however, since valves 233 in bores 225, 232 are opened, formation fluids are free to flow through bores 224, 225, 232, 236 and choke valve 234. Next, valve 233 in bore 232 is transitioned closed. As that valve 233 is transitioned closed, the pressure of wellbore fluids within lower assembly 210 are monitored with pressure transducer 227. As long as the formation fluid pressures within assembly 210 is within acceptable limits, valve 233 in bore 232 continues to be closed until it is fully closed. Once valve 233 in bore 232 is closed, valve 233 in bore 225 may also be fully closed to provide redundancy. With each valve 233, 263 closed, wellbore 101 is contained and shut-in. It should be appreciated that inclusion of choke valve 234 and the staged shut-in of wellbore 101 via sequential closure of valves 233, 263 enables a "soft" shut-in, thereby offering the potential to reduce the likelihood of an abrupt formation pressure surge, which may damage subsea components (e.g., BOP 120, assembly 210, assembly 250, assembly 290) and lead to another subsea blowout.

[00110] Once wellbore 101 is shut-in and generally under control, and the necessary infrastructure for producing wellbore 101 are in place (e.g., hydrocarbon storage vessels, risers, manifolds, flow lines, etc. are installed), wellbore 101 may be produced via kill-flowback assembly 290 and/or conduit 235. For example, depending on the particular circumstances, wellbore 101 may be produced through flowback assembly 290 with valves 233 closed and valves 263 opened, produced through conduit 235 with valves 233 opened and valves 263 closed, or produced through both assembly 290 and conduit 235 with all valves 233, 263 opened.

[00111] As previously described, lower assembly 210 includes chemical injection system 240, and upper assembly 250 includes a chemical injection system 270. Injection systems 240, 270 may be used prior to, during, or after shutting-in wellbore 101 to inject chemicals into bores 224, 262, respectively, and wellbore 101. For example, chemicals such as glycol and/or methanol may be injected to reduce hydrate formations within assemblies 210, 250 which might otherwise hamper or prevent the ability to install assemblies 210, 250. As another example, chemical dispersants may be injected into hydrocarbons flowing through assemblies 210, 250 after installation to mitigate volume of oil and volatile organic compounds generated at the sea surface.

[00112] Containment cap 200 previously described may also be installed onto mandrel 151 or flex joint 143 of LMRP 140. Installation of cap 200 onto flex joint 143 of LMRP 140 will now be described. As shown in Figures 1 and 2, riser adapter 145 is coupled to flex joint 143; the upper end of riser adapter 145 comprises flange 145a for coupling adapter 145 to mating flange 118 at the lower end of riser 115. However, in the embodiment shown, lower end 222b of spool piece 222 (Figure 8) comprises receptacle 150b for connecting to a complementary mating hub 150a to form a wellhead-type connection 150. Thus, receptacle 150b is not configured or designed to mate and engage with flange 145a. Accordingly, referring now to Figure 22, in this embodiment, an adapter or transition spool 330 is employed to couple lower assembly 210 of cap 200 to riser adapter 145.

[00113] Referring to Figure 22, in this embodiment, transition spool 330 has a central or longitudinal axis 335, a first or upper end 330a, a second or lower end 330b opposite end 330a, and a flow bore 331 extending axially between ends 330a, b. Upper end 330a comprises an upward-facing hub 150a configured to releasably engage complementary receptacle 150b at lower end 222b of containment cap 200 to form a wellhead-type connection 150, lower end 330b comprises a mule shoe 340 configured to be coaxially inserted into riser adapter 145 following removal of riser 115 from flex joint 143. An annular flange 334 is axially disposed between ends 330a, b, and is sized and configured to mate and engage with flange 145a of flex joint 143. Flange 334 includes a plurality of circumferentially spaced holes 334a. Bolts 334b are pre-disposed in holes 334a, and a resilient annular band 336 is disposed about the upper ends of bolts 334b. Band 336 urges the upper ends of bolts 334b radially inward relative to their lower ends and holes 334a, thereby skewing and angling bolts 334b relative to holes 334a (i.e., bolts 334b are not coaxially aligned with holes 334a). In this manner, band 336 maintains the position of bolts 334b extending into holes 334a during deployment of transition spool 330, thereby reducing the likelihood of one or more bolts 334b disengaging their corresponding

holes 334a and being dropped to the sea floor 103 during deployment and installation of containment cap 200.

[00114] Referring still to Figure 22, a pair of circumferentially spaced alignment guides or pins 338 extend axially downward from flange 334. Pins 338 are sized and positioned to coaxially and rotationally align flange 334 of transition spool 330 relative to flange 145a of flex joint 143 such that holes 334a are coaxially aligned with corresponding holes in flange 145a. Transition spool 330 also includes a plug 337 extending axially through flange 334. Plug 337 is positioned and oriented for axial insertion into outlet 149b of mud boost line 149 in flange 145a when flanges 145a, 334 are coupled together. Plug 337 functions to close off and seal outlet 149b, thereby preventing the leakage of hydrocarbon fluids therethrough in the event mud boost valve 149c fails or otherwise leaks. In this embodiment, plug 337 is pre-installed in transition spool 330 prior to deployment such that it engages mating outlet 149b as flanges 145a, 334 axially abut. Alternatively, plug 337 may be installed by an ROV 170 after flanges 145a, 334 are secured together. Plug 337 may be fitted with an adapter for coupling a chemical supply line to plug 337 to inject a chemical into outlet 149b in the event it is necessary to flush hydrates from outlet 149b.

[00115] Mule shoe 340 is a tubular extending axially downward from flange 334. In this embodiment, shoe 340 also includes a plurality of circumferentially spaced elongate through slots 343 extending radially from the outer cylindrical surface of shoe 340 to bore 331. In the embodiment, slots 343 are oriented parallel to axis 335. In other embodiments, the slots in the mule shoe (e.g., slots 343 in mule shoe 340) may be omitted. Moreover, although this embodiment of transition spool 330 includes mule shoe 340, in other embodiments, the mule shoe (e.g., mule shoe 340) is completely eliminated. In such embodiments, a plurality of guide pins (e.g., guide pins 338) facilitate the alignment and coupling of the transition spool (e.g., spool 320) and the flex joint (e.g., flex joint 143)

[00116] As will be described in more detail below, during installation of transition spool 330 onto flex joint 143, mule shoe 340 is coaxially aligned with joint 143 and axially advanced into joint 143 until flanges 145a, 334 axially abut. During insertion of mule shoe 340 into flex joint 143, through slots 343 provide a flow path for hydrocarbon fluids discharged from wellbore 101 through BOP 120 and LMRP 140, thereby offering the potential to relieve wellbore pressure during installation.

[00117] To facilitate the alignment and insertion of mule shoe 340 into flex joint 143, lower end 330b is angled or tapered in side view (i.e., when viewed perpendicular to axis 335). Specifically, lower end 330b is oriented at an angle β relative to axis 335. Angle β is preferably

between 30° and 60°. In this embodiment, angle β is 45°. Tapered lower end 330b also facilitates the axial advancement of mule shoe 340 into another component (e.g., flex joint 143) that is bent or angled relative to vertical and/or that contain pipes or tubulars disposed therein. For example, mule shoe 340 may be inserted into another component and slowly axially advanced. As shoe 340 is advanced, tapered end 330b slidingly engages the component, thereby guiding shoe 340 into the component. In addition, tapered end 330b slidingly engages and guides tubulars within the component into bore 331. In other words, tapered end 330b enables mule shoe 340 to wedge itself radially between the component and the tubulars disposed therein. This may be particularly advantageous in instances where mule shoe 340 is coupled to a component that contains damaged tubulars or pipes that cannot be removed.

[00118] To prepare flange 145a for sealing engagement with flange 334, riser 115 is removed from flex joint 143, and any tubulars or debris extending upward from flange 145a are preferably cut off substantially flush with flange 145a. In addition, riser adapter 145 is preferably oriented vertically and locked in the vertical position prior to coupling transition spool 330, lower assembly 210, upper assembly 250, kill-flowback assembly 290, or combinations thereof to riser adapter 145. This offers the potential to simplify installation of these components as well as reduce moments experienced by adapter 145 following installation of these components. More specifically, since riser adapter 145 is designed to angularly deflect and pivot relative to base 144, the moments exerted on riser adapter 145 following attachment of such components may cause riser adapter 145 to undesirably pivot and/or break. However, by straightening flex joint 143 (i.e., orienting riser adapter 145 vertically) and locking riser adapter 145 in place, such moments can be reduced and resisted without adapter 145 pivoting or breaking. In general, riser adapter 145 may be oriented vertically and locked in the vertical orientation by any suitable systems and/or methods. Examples of suitable systems and methods for orienting riser adapter 145 vertically and locking riser adapter 145 in the vertical orientation are disclosed in U.S. patent application no. 61/482,132 filed May 3, 2011, and entitled "Adjustment and Restraint System for a Subsea Flex Joint," which is hereby incorporated herein by reference in its entirety for all purposes.

[00119] Referring briefly to Figures 23-25, an embodiment of a system 300 for adjusting and restraining the angular orientation of riser adapter 145 relative to base 144, BOP 120, and wellhead 130 is shown. In this exemplary embodiment, the system 300 includes a plurality of base members 301 circumferentially spaced about and mounted to the upper end of base 144 and a plurality of hydraulic cylinder assemblies 310, one cylinder assembly 310 is radially positioned between each base member 301 and riser adapter 145. Each base member 301

includes an upper pocket or cavity 302 within which one cylinder assembly 310 is seated and a lower pocket or cavity 303 that receive the upper ends of studs and nuts 304 extending upward from base 144.

[00120] Each hydraulic cylinder assembly 310 includes a cylinder member 311 that rests in the upper pocket 302 and a piston member 312 extending from cylinder member 311. Piston member 312 is hydraulically actuated to extend or retract relative to cylinder member 311. Piston member 312 includes a contact member 313 for engaging the outer surface of riser adapter 145. Upon actuation, piston member 312 can be extended axially from cylinder member 311 to exert a radial force on riser adapter 145 to pivot riser adapter 145 to the vertical position. In general, hydraulic cylinder assembly 310 may be any one of several robustly rated cylinders, including, for example, Enerpac® RC-502 hydraulic cylinders and/or Enerpac® RC-504 hydraulic cylinders which have an approximately 50-ton cylinder capacity. Hydraulic cylinders with various other capacities and characteristics are also contemplated and known to one having ordinary skill.

[00121] Base members 301 and cylinder assemblies 310 are positioned about riser adapter 145 with one or more subsea ROVs (e.g., ROVs 170). In particular, base members 301 and cylinder assemblies 310 are circumferentially positioned and spaced to exert the appropriate radial forces on riser adapter 145 to vertically orient riser adapter 145.

[00122] Referring now to Figure 26, an embodiment of another system 340 for adjusting and restraining the angular orientation of riser adapter 145 relative to base 144, BOP 120, and wellhead 130 is shown. In this exemplary embodiment, the system 340 includes a plurality of stud caps 341 mounted to the upper ends of the studs extending upward from base 144 and a plurality of hydraulic cylinder assemblies 345 (only one cylinder assembly 345 is shown in Figure 26) radially positioned between caps 341 and riser adapter 145. Each cap 341 is a rigid cylinder including a counterbore or cavity in its lower end that receives the upper end of one stud extending upward from base 144.

[00123] Referring now to Figures 26 and 27, each hydraulic cylinder assembly 345 includes a body 346 and a piston-cylinder assembly 347 coupled to body 346. Body 346 includes a piston-cylinder housing 346a and a flange 346b extending downward from housing 346a. Piston-cylinder assembly 347 is disposed within housing 346a and includes a piston member 348 hydraulically actuated to extend or retract relative to housing 346a. Piston member 348 includes a contact face 348a for engaging the outer surface of riser adapter 145. An ROV handle 349 is coupled to body 346 to facilitate positioning of assembly 345 by a subsea ROV.

[00124] To adjust the angle between riser adapter 145 and base 144, caps 341 are mounted on the studs extending upward from base 144, and one or more assemblies 345 are circumferentially disposed about riser adapter 145. In particular, assemblies 345 are radially positioned between caps 341 and riser adapter 145 with housing 346a engaging caps 341, piston member 348 extending radially inward from housing 346a towards riser adapter 145, and flange 346b engaging the inner surface of base 144. Next, assemblies 347 are actuated to extend piston members 348 radially inward into engagement riser adapter 145. Continued actuation of assemblies 347 causes piston members 348 to exert a radial force on riser adapter 145 to pivot riser adapter 145 to the desired vertical position. In general, hydraulic cylinder assembly 345 may be any one of several robustly rated cylinders, including, for example, Enerpac® RC-502 hydraulic cylinders and/or Enerpac® RC-504 hydraulic cylinders which have an approximately 50-ton cylinder capacity. Hydraulic cylinders with various other capacities and characteristics are also contemplated and known to one having ordinary skill.

[00125] Caps 341 and cylinder assemblies 345 are positioned about riser adapter 145 with one or more subsea ROVs (e.g., ROVs 170). In particular, caps 341 and cylinder assemblies 345 are circumferentially positioned and spaced to exert the appropriate radial forces on riser adapter 145 to vertically orient riser adapter 145.

[00126] Once adapter 145 is oriented vertically, it is preferably locked in the vertical orientation so that it does not bend or flex during or after installation of a containment cap. For example, systems 300, 340 can be uniformly circumferentially disposed about riser adapter 145 to exert balanced radial forces that maintain riser adapter 145 in the vertical orientation. Alternatively, rigid wedges may be disposed in the annulus radially positioned between riser adapter 145 and base 144, and uniformly circumferentially spaced about riser adapter 145 once adapter 145 is vertically oriented to maintain adapter 145 in the vertical orientation.

[00127] Referring now to Figures 28 and 29, an embodiment of a set 350 of wedge members 360 for locking riser adapter 145 in a vertical orientation is shown. Wedge members 360 are sized and configured to be positioned in the annulus between riser adapter 145 and cylindrical base 144. In particular, wedge members 360 are numerically labeled (e.g., "1", "2", "3", "4" . . .) to designate the circumferential order in which wedge members 360 are arranged within set 350. For example, wedge member 360 labeled "1" is circumferentially adjacent wedge member 360 labeled "2", which is circumferentially adjacent wedge member 360 labeled "3", and so on. With wedge members 360 arranged in the proper circumferential order, set 350 defines an inner annular cylindrical surface 351 disposed at an inner diameter D_i and an outer annular cylindrical surface 352 disposed at an outer diameter D_o . Inner diameter D_i is

substantially the same or slightly greater than the outer diameter of riser adapter 145, and outer diameter D_o is substantially the same or slightly less than the inner diameter of base 144. Thus, when wedge members 360 are arranged in the proper circumferential order and disposed about riser adapter 145, inner surface 351 engages riser adapter 145 and outer surface 352 engages the inner surface of base 144, thereby locking the position and angle of riser adapter 145 relative to base 144. In this embodiment, an ROV handle 361 is coupled to each wedge member 360 to facilitate the independent positioning wedge members 360 by a subsea ROV.

[00128] As best shown in Figure 29, inner surface 351 is centered about a first centrum 351a and outer surface 352 is centered about a second centrum 352a that is radially offset from centrum 351a. The degree of radial offset of centums 351a, 352a can be varied to orient and lock riser adapter 145 at a particular angle relative to base 144.

[00129] Referring now to Figures 30A-30P, containment cap 200 previously described is shown being deployed and installed subsea on flex joint 143 of LMRP 140, after riser adapter 145 has been prepared for engagement with transition spool 330 as previously described, to contain and shut-in wellbore 101. Since receptacle 150b at lower end 222b of spool piece 222 is not configured or designed to mate and engage with flange 145a, transition spool 330 previously described is first deployed and coupled to LMRP 140, followed by deployment and installation of assemblies 210, 250, 290. In Figures 30A-30D, transition spool 330 is shown being controllably lowered subsea and secured to flex joint 143; in Figures 30E-30H, lower assembly 210 is shown being controllably lowered subsea and secured to transition spool 330; in Figures 30I-30L, upper assembly 250 is shown being controllably lowered subsea and secured to lower assembly 210; and in Figures 30M-30P, kill-flowback assembly 290 is shown being controllably lowered subsea and secured to upper assembly 250.

[00130] Referring first to Figure 30A, transition spool 330 is shown being controllably lowered subsea with wireline 181 and leads 253 secured to spool 330 and extending to a surface vessel. Due to the weight of spool 330, wireline 181 and leads 253 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 is preferably employed to support and lower spool 330 on wireline 181. Although wireline 181 is employed to lower spool 330 in this embodiment, in other embodiments, spool 330 may be deployed subsea with a running tool mounted to the lower end of a pipe string. Using wireline 181, spool 330 is lowered subsea under its own weight from a location generally above and laterally offset from wellbore 101, BOP 120, and LMRP 140 and outside of plume 160 to reduce the potential for hydrate formation within spool 330.

[00131] Moving now to Figure 30B, spool 330 is lowered laterally offset from riser adapter 145 (outside of plume 160) until mule shoe 340 is slightly above flange 145a. As spool 330 descends and approaches riser adapter 145, ROVs 170 monitor the position of spool 330 relative to flex joint 143. Next, as shown in Figure 30C, transition spool 330 is moved laterally into position immediately above riser adapter 145 with mule shoe 340 substantially coaxially aligned with riser adapter 145. In addition, spool 330 is rotated about axis 335 to substantially align guide pins 338 with corresponding holes 148 in flange 145a. One or more ROVs 170 may utilize their claws 172 to guide and rotate spool 330 into the proper alignment relative to flange 145a.

[00132] Due to its own weight, spool 330 is substantially vertical, whereas riser adapter 145 may be oriented at an angle relative to vertical. Thus, it is to be understood that perfect coaxial alignment of mule shoe 340 and flex joint 143, as well as perfect alignment of pins 338 and mating holes in flange 145a, may be difficult.

[00133] With mule shoe 340 positioned immediately above and generally coaxially aligned with riser adapter 145, and guide pins 338 aligned with corresponding holes in flange 145a, wireline 181 lower spool 330 axially downward, thereby inserting and axially advancing pins 338 into corresponding holes 148 and inserting and axially advancing mule shoe lower end 330b into riser adapter 145 until flange 334 axially abuts and engages flange 145a as shown in Figure 30D. The frustoconical surface on the lower end of each pin 338 functions to guide each pin 338 into its corresponding hole 148, even if pins 338 are initially slightly misaligned with holes 148. Likewise, taper on lower end 330b functions to guide the insertion and coaxial alignment of spool 330 and riser adapter 145 as spool 330 is lowered from a position immediately above riser adapter 145, even if mule shoe 340 is initially slightly misaligned with riser adapter 145. During installation of spool 330, emitted hydrocarbons flow freely through spool 330 and slots 343 in mule shoe 340, thereby relieving well pressure and offering the potential to reduce the resistance to the axial insertion of mule shoe 340 into riser adapter 145 and coupling of transition spool 330 thereto.

[00134] With mule shoe 340 sufficiently seated in riser adapter 145 and flange 334 abutting mating flange 145a, holes 334a are coaxially aligned with corresponding holes 147 in flange 145a and plug 337 is disposed in mud boost outlet 149b. Next, one ROV 170 cuts band 336, thereby allowing bolts 334b to drop into holes 147. One or more ROVs 170 may also help facilitate the lowering of bolts 334b into holes 147 if necessary. Bolts 334b may then be tightened with ROVs 170 to rigidly secure spool 330 to riser adapter 145. With a sealed, secure

connection between spool 330 and riser adapter 145, ROVs 170 decouple leads 253 from transition spool 330. Leads 253 may then be removed to the surface with wireline 181.

[00135] Once transition spool 330 is securely coupled to riser adapter 145, assemblies 210, 250, 290 are deployed in the same manner as previously described with respect to Figures 20A-20L with the exception that lower assembly 210 is connected to transition spool 330. Specifically, as shown in Figures 30E-30H, lower assembly 210 is lowered subsea as previously described and coupled to transition spool 330 via engagement of upward-facing hub 150a of transition spool 330 and downward-facing receptacle 150b of lower assembly 210 to form a wellhead-type connection 150 therebetween. Next, as shown in Figures 30I-30L, upper assembly 250 is lowered subsea and connected to lower assembly 210 as previously described, and then, as shown in Figures 30M-30P, kill-flowback assembly 290 is lowered subsea and connected to upper assembly 250 as previously described. Wellbore 101 may be contained and shut-in with assemblies 210, 250 (with or without the use of kill fluids via assembly 290) in the same manner as previously described. It should also be appreciated that prior to installation of kill-flowback assembly 290, or after removal of kill-flowback assembly 290, aligned bores 224, 262 enable re-entry of LMRP 140, BOP 120, and wellbore 101.

[00136] Once wellbore 101 is shut-in and generally under control, and the necessary infrastructure for producing wellbore 101 are in place (e.g., hydrocarbon storage vessels, risers, manifolds, flow lines, etc. are installed), wellbore 101 may be produced via flowback assembly 290 and/or conduit 235. In addition, injection systems 240, 270 may be used prior to, during, or after shutting-in wellbore 101 to inject chemicals into bores 224, 262, respectively, and wellbore 101. Although Figures 30A-30P illustrate containment cap 200 being deployed and installed subsea on riser adapter 145, installation of cap 200 on LMRP 140, wellhead 130, or BOP 120 is performed in the same fashion with the exception of the preparation of the landing site (e.g., LMRP 140, wellhead 130, or BOP 120).

[00137] Referring now to Figure 31, another embodiment of a containment cap 400 for capping wellbore 101 previously described (Figure 4), and containing the hydrocarbon fluids therein is shown. Containment cap 400 is similar to containment cap 200 previously described. Namely, containment cap 400 is modular, and includes a first or lower assembly 210 as previously described. For purposes of clarity, frame 211, second pipe spool 230, chemical injection system 240, and sensor system 226 of lower assembly 210 are not shown in Figure 31. Unlike cap 200 previously described, in this embodiment, upper assembly 250 and kill-flowback assembly 290 are not included. Rather, upper assembly 250 has been replaced with a valve assembly 450 coaxially disposed in main bore 224 of lower assembly 210, and kill-flowback

assembly 290 has been replaced with a cap 470. Valve assembly 450 is releasably maintained within lower assembly 210 by cap 470. Cap 470 is securely attached to lower assembly 210 with an annular coupling member 480 that forms wellhead-type connections 150 with cap 470 and lower assembly 210. Assemblies 210, 450 function together to contain and shut-in wellbore 101, whereas cap 470 facilitates the deliver of kill-weight fluids to wellbore 101 as well as the production of wellbore 101 once it is contained and controlled.

[00138] As previously described, lower assembly 210 is air-freightable. In this embodiment, valve assembly 450, cap 470, and coupling 480 are also air-freightable. Thus, lower assembly 210, valve assembly 450, cap 470, and coupling 480 are each sized and configured to be transported by air on its own or with one or more of assembly 210, assembly 450, cap 470, and coupling 480. In other words, lower assembly 210, valve assembly 450, cap 470, and coupling 480 each has a weight and dimensions suitable for air transport. In this embodiment, valve assembly 450 has a weight under 30 tons, and thus, may be transported along with lower assembly 210.

[00139] Referring still to Figure 31, valve assembly 450 comprises a tubular body 451 having a central or longitudinal axis 452, a first or upper end 451a, a second or lower end 451b, and a throughbore 453 extending axially between ends 451a, b. Assembly 450 also includes a pair of axially-spaced valves 454 disposed along throughbore 453. Valves 454 control the flow of fluids through bore 453. Namely, each valve 454 has an open position allowing fluid flow therethrough and a closed position restricting and/or preventing fluid flow therethrough. Valves 454 are positioned in series along throughbore 453. Consequently, fluid flow through bore 453 is restricted and/or prevented if one or both valves 454 are closed, and fluid flow through bore 453 is permitted if both valves 454 are opened. In general, each valve 454 may comprise any type of valve suitable for the anticipated fluid pressures and fluids in bore 453 including, without limitation, ball valves, gate valves, and butterfly valves. Further, each valve 454 may be manually actuated, hydraulically actuated, mechanically actuated, or electrically actuated valves. In this embodiment, each valve 454 is a hydraulically actuated ball valve rated for a 15k psi pressure differential. Each valve 454 may be controlled and actuated subsea with an ROV. Alternatively, each valve 454 may be controlled from the surface with hydraulic flow lines or flying leads extending from the surface and coupled to valves 454 via a panel located on lower assembly 210.

[00140] Valve assembly 450 is partially disposed within main bore 224 - upper end 451a extends axially from bore 224, and lower end 451b is disposed in bore 224. An annular insert 460 is coaxially disposed within bore 224 axially between assembly 450 and an annular

shoulder 224a within bore 224. Insert 460 has a first or upper end 460a, a second or lower end 460b opposite end 460a, and a flow passage 461 extending axially between ends 460a, b. Upper end 460a comprises a cylindrical recess or counterbore 462 that receives lower end 451b, and lower end 460b comprises a reduced outer diameter portion that extends into bore 224 below shoulder 224a. Thus, insert 460 is seated in bore 224 against shoulder 224a, and tubular body 451 is seated in recess 462. A plurality of annular seal assemblies 470 are radially disposed between tubular body 451 and spool piece 222. Seal assemblies 470 restrict and/or prevent fluids from flowing axially between body 451 and spool piece 222.

[00141] Referring still to Figure 31, cap 470 maintains valve assembly 450 in bore 224 with lower end 451b seated in insert 460. Cap 470 is coaxially aligned with bores 224, 453 and has a first or upper end 470a, a second or lower end 470b, and a flow passage 471 extending axially between ends 470a, b. In this embodiment, upper end 470a comprises an upward-facing flow line connection hub 239a and lower end 470b comprises a downward-facing hub 150a. A cylindrical recess or counterbore 472 extends axially from lower end 470b and defines an annular shoulder 473 in passage 471. Tubular member 451 extends into recess 472 and is seated against shoulder 473. Ends 470b, 222a axially abut and are held together with an annular coupling member 480. Specifically, coupling member 480 is disposed about ends 470b, 222a and includes an upward-facing receptacle 150b releasably secured to hub 150a at end 470b to form a wellhead-type connection 150 therebetween, and a downward-facing receptacle 150b releasably secured to hub 150a at end 222a to form a wellhead-type connection 150 therebetween. Upward-facing hub 239a at upper end 470a releasably engages and interlocks a mating receptacle at the lower end of a flow line for injecting kill weight fluids into cap 400 and wellbore 101 or producing wellbore 101.

[00142] Containment cap 400 is deployed subsea and installed on wellhead 130, BOP 120, or LMRP 140 to contain and shut-in wellbore 101, and/or produce wellbore 101. To simplify deployment, containment cap 400 is preferably deployed and installed subsea as a single unit in a single trip. In other words, in this embodiment, valve assembly 450 is preferably installed in lower assembly 210, and cap 470 coupled to lower assembly 210 with coupling 480 at the surface 102, and then the entire pre-assembled cap 400 lowered subsea. To install cap 400 onto BOP 120, riser 115 is removed from LMRP 140, and LMRP 140 is removed from BOP 120. Then, cap 400 is lowered subsea on a pipestring 180 or wireline 181 coupled to hub 239a, and securely attached to BOP 120 with wellhead-type connection 150. To install cap 400 onto wellhead 130, riser 115 is removed from LMRP 140, LMRP 140 is removed from BOP 120, and BOP 120 is removed from wellhead 130. Then, cap 400 is lowered subsea on a pipestring

180 or wireline 181 coupled to hub 239a, and securely attached to wellhead 130 with wellhead-type connection 150. To install cap 400 onto LMRP 140, riser 115 is removed from LMRP 140, then transition spool 330 is lowered subsea and securely attached to riser adapter 145 as previously described. Next, cap 400 is lowered subsea and securely attached to transition spool 330 with wellhead-type connection 150. In each case, cap 400 is preferably lowered subsea laterally offset from wellbore 101 and outside of plume 160, and then moved laterally over the landing site (e.g., BOP 120, transition spool 330, or wellhead 130) and coupled thereto with a wellhead type-connection 150. One or more ROVs 170 may be employed to facilitate the installment of cap 400.

[00143] Although cap 400 is preferably assembled at the surface 102, and then lowered subsea as a single unit, in other embodiments, lower assembly 210 and valve assembly 450 may be lowered subsea separately, and then assembled into cap 400 subsea. For instance, lower assembly 210 may be lowered subsea and installed on wellhead 130, BOP 120, or transition spool 330 as previously described, and then valve assembly 450 may be lowered subsea with wireline 181 or pipestring 180, installed in bore 224, and secured to assembly 210 with cap 470 and annular coupling 480.

[00144] Referring still to Figure 31, upon installation of containment cap 400, hydrocarbons are free to flow through cap 400. To contain and shut-in wellbore 101, valves 233 in bores 225, 232 and valves 454 in bore 453 are manipulated by subsea ROVs 170. To utilize kill weight fluids in shutting in wellbore 101, a kill fluids supply line is connected to hub 239a at upper end 470a of cap 470 prior to initiating the shut-in procedures. However, if kill fluids are not utilized to aid in shutting in wellbore 101, the shut-in procedures may be initiated prior to installation of a flow line onto hub 239a.

[00145] To shut-in wellbore 101, valves 233 in flow lines 237, 238 are both closed, and valves 233 in bores 225, 232 are both maintained opened while upper valve 454 is transitioned closed. As upper valve 454 is transitioned closed, the pressure of wellbore fluids within lower assembly 210 are monitored with pressure transducer 226 and the pressure of wellbore fluids within upper assembly 250 are monitored with pressure sensor 287. As long as the formation fluid pressures within assemblies 210, 450 are within acceptable limits, upper valve 454 continues to be closed until it is fully closed. Once upper valve 454 is closed, lower valve 454 may also be fully closed to provide redundancy. With both valves 454 closed, fluid flow through bore 453 is restricted and/or prevented, however, since valves 233 in bores 225, 232 are opened, formation fluids are free to flow through bores 224, 225, 232, 236 and choke valve 234. Next, valve 233 in bore 232 is transitioned closed. As that valve 233 is transitioned

closed, the pressure of wellbore fluids within lower assembly 210 are monitored with pressure transducer 226. As long as the formation fluid pressures within assembly 210 is within acceptable limits, valve 233 in bore 232 continues to be closed until it is fully closed. Once valve 233 in bore 232 is closed, valve 233 in bore 225 may also be fully closed to provide redundancy. With each valve 233, 454 closed, wellbore 101 is contained and shut-in. Accordingly, in this embodiment, valves 454 of assembly 450 perform the same function(s) as valves 263 of upper assembly 250 previously described. It should be appreciated that inclusion of choke valve 234 and the staged shut-in of wellbore 101 via sequential closure of valves 233, 454 enables a "soft" shut-in, thereby offering the potential to reduce the likelihood of an abrupt formation pressure surge, which may damage subsea components (e.g., BOP 120, assembly 210, assembly 450, assembly 290) and lead to another subsea blowout.

[00146] Once wellbore 101 is shut-in and generally under control, and the necessary infrastructure for producing wellbore 101 are in place (e.g., hydrocarbon storage vessels, risers, manifolds, flow lines, etc. are installed), wellbore 101 may be produced via hub 239a at upper end 470a of cap 470 and/or conduit 235. For example, depending on the particular circumstances, wellbore 101 may be produced through cap 470 with valves 233 closed and valves 454 opened, produced through conduit 235 with valves 233 opened and valves 454 closed, or produced through both cap 470 and conduit 235 with all valves 233, 454 opened.

[00147] As previously described, lower assembly 210 includes chemical injection system 240. Injection systems 240 may be used prior to, during, or after shutting-in wellbore 101 to inject chemicals into bores 224, 453, respectively, and wellbore 101. For example, chemicals such as glycol may be injected to reduce hydrate formations within assemblies 210, 450.

[00148] In the manner described, embodiments of containment caps described herein (e.g., caps 200, 400) may be deployed subsea from a surface vessel and installed on a subsea wellhead (e.g., wellhead 130), BOP (e.g., BOP 120) or LMRP (e.g., LMRP 140) that is emitting hydrocarbon fluids into the surrounding sea. Once securely installed subsea, a series of valves are actuated and closed to achieve a "soft" shut-in of the wellbore. Pressure and temperature sensors are included to measure the pressure and temperature of the wellbore fluids, thereby enabling an operator to manage the opening and closing of valves in a manner that reduces the likelihood of a blowout while attempting to shut-in the wellbore. For example, while shutting in the wellbore, the valves are preferably closed in a sequential order while the wellbore pressure is continuously monitored. In the event closure of a particular valve triggers an undesirable increase in wellbore pressure, that valve (or another valve) may be immediately opened to relieve the increased wellbore pressure, thereby offering the potential to avert a

blowout while shutting in the well. Likewise, after the well is shut-in, the wellbore pressure may be monitored so that a valve may be opened in the event of an unexpected spike in wellbore pressure to relieve such wellbore pressure increase.

[00149] Referring now to Figure 32, an overview of a method 500 for deploying and installing an embodiment of a subsea containment cap (e.g., containment cap 200, 400) on a subsea wellhead, a BOP, an LMRP (e.g., LMRP mandrel), or a flex joint riser adapter that is emitting hydrocarbon fluids is shown. Starting in block 501, a suitable subsea landing site is identified. In the embodiment of offshore system 100 previously described, subsea BOP 120 is mounted to wellhead 130 at the sea floor 103 with a wellhead-type connection 150, LMRP 140 is mounted to BOP 120 with wellhead-type connection 150, flex joint 143 is mounted to LMRP 140 via mandrel 151, and riser 115 is coupled to riser adapter 145 with a flanged connection. Thus, potential landing sites include riser adapter 145 of LMRP 140 following removal of riser 115, LMRP mandrel 151 following removal of flex joint 143, BOP 120 following removal of LMRP 140, and wellhead 130 following removal of BOP 120. These represent particularly suitable landing sites as the various connections between these components may be decoupled subsea with the aid of ROVs 170. The ultimate selection of the most desirable landing site may vary from well-to-well and depends on a variety of factors including, without limitation, the ease with which a particular connection may be broken and re-connected, the type of damage, the component(s) that are damaged (e.g., BOP 120, LMRP 140, riser 115, etc.), the potential for adverse effects when preparing the selected landing site (e.g., exposure of internal debris, trapped pipes, etc.), the potential for increased well flow/hydrocarbon emissions, the ability of the landing site and associated hardware (e.g., BOP 120, LMRP 140, etc.) to take the load of the containment cap, or combinations thereof.

[00150] If the selected landing site is mandrel 151 of LMRP 140 or riser adapter 145, the connection between riser 115 and riser adapter 145 is broken, and riser 115 is removed from riser adapter 145 according to block 506. If the selected landing site is riser adapter 145, then the appropriate transition spool (e.g., transition spool 330), as needed, is deployed and installed subsea according to block 510. However, if the landing site is LMRP mandrel 151, then flex joint 143 (including riser adapter 145) is removed at block 535. Thereafter, appropriate transition spool (e.g., transition spool 330), as needed, is deployed and installed subsea on mandrel 151 at block 536. On the other hand, if the selected landing site is BOP 120, riser 115 is removed from riser adapter 145, connection 150 between LMRP 140 and BOP 120 is broken, and LMRP 140 is removed from BOP 120 according to block 507. Still further, if the selected landing site is wellhead 130, riser 115 is removed from riser adapter 145, connection 150

between LMRP 140 and BOP 120 is broken, LMRP 140 is removed from BOP 120, connection 150 between BOP 120 and wellhead 130 is broken, and BOP 120 is removed from wellhead 130 according to block 508.

[00151] It should be appreciated that identification of the landing site also influences whether a transition spool (e.g., transition spool 330) is necessary to couple the containment cap to landing site. For example, if the landing site includes a connector or hub (e.g., hub 150a) configured to mate and engage receptacle 150b at lower end 222b, then a transition spool is not necessary. On the other hand, if the landing site comprises a connector or hub that is not configured to mate and engage receptacle 150b at lower end 222b, then a transition spool is necessary to transition from receptacle 150b at lower end 222b to the particular type of connector or hub at the landing site.

[00152] Moving now to block 515, before, during, or after preparation of the landing site according to blocks 506, 507, 508, the transition spool (e.g., transition spool 330) and the containment cap components (e.g., assemblies 210, 250, 290 of containment cap 200, or assemblies 210, 450, cap 470, and coupling 480 of containment cap 400) are transported to the offshore deployment location. In general, the transition spool and containment cap components may be transported by air to a suitable onshore staging site, and then transported offshore by a boat or surface vessel. Air transport of the transition spool and/or any one or more of the components of the containment cap may be particularly desirable for transition spools and/or components stored or housed at a geographic locale that is distant the offshore deployment location since long range air transport is typically much faster than long range sea or land transport.

[00153] Once the transition spool (if necessary) and the assemblies of the containment cap 200, 400 have been transported to the offshore site, they may be deployed and installed subsea to form cap 200, 400 as previously described in block 520. Next, in block 525, wellbore 101 is contained and shut-in with containment cap 200, 400 as previously described. With wellbore 101 under control, flowback assembly 290 and/or conduit 235 may be used to produce wellbore 101 according to block 530.

[00154] Previously described was an embodiment in which a particular transition spool 330 was employed in order to couple containment cap 200 to riser adapter 145 of a particular flex joint 143. However, manufacturers have developed numerous types of riser flex joints, lower marine riser packages, BOPs, and wellheads. In particular, there are a number of potentially different connector profiles across riser flex joints, lower marine riser packages, BOPs, and wellheads. As previously described, in some cases, the landing site on the riser adapter, LMRP, BOP, or

wellhead may have a connector or hub with a profile designed to directly mate and engage with receptacle 150b disposed at lower end 222b. However, in other cases, the landing site may have a connector or hub with a profile that is not compatible with receptacle 150b at lower end 222b. In such embodiments, a transition spool is employed to transition between the connector profile at the landing site and receptacle 150b at lower end 222b. Consequently, a variety of differently configured transition spools are required to transition between receptacle 150b at end 222b to the numerous connector profiles at the landing site. This may be best explained with reference to Figure 33. As shown, lower marine riser package 140 is releasably coupled to BOP 120 which, in turn, is releasably coupled to wellhead 130, as previously explained. In this example, five different riser flex joints 143A-143E have identically-configured lower connectors that are suitably-configured for connecting to the upper connection of LMRP 140 (i.e., mandrel 151), but each has a differently-configured, upwardly-extending riser adapter 145A-145E, respectively, that, in the normal course of drilling and production, couples to a riser (not shown in Figure 33). In the situation where it is desirable to couple a containment cap 200, 400 to one of riser adapters 145A-145E, a differently-configured transition spool is required in each instance.

[00155] More particularly, Figure 33 shows five differently-configured riser adapters 145A-145E, each suitable for connection to a differently-configured transition spool, shown as 330A-330E. It should be understood that the schematic representations of the riser adapter profiles 145A-145E do not represent actual shapes or actual profiles of riser adapters, but are used herein merely to illustrate that riser adapter 145A has a different configuration than riser adapter 145B, which has a different configuration than riser adapter 145C, and so on. Having such differently-configured connector profiles requires that transition spools 330A-330E have downwardly-extending connectors and associated connector profiles that are different from one another so as to be configured to releasably connect to the corresponding riser adapter 145A-145E. Although the lower end of each transition spool 330A-330E is different to accommodate a differently configured riser adapters 145A-145E, the upper end of each transition spool 330A-330E is configured the same for engagement, in each instance, with a containment cap of a uniform design. In this instance, each transition spool 330A-330E includes a wellhead-type connection hub 150a at its upper end configured to mate and engage the complementary female receptacle 150b at the lower end 222b of cap 200, 400 to form a standard wellhead-type connection 150.

[00156] Referring now to Figures 34 and 35, an embodiment of a containment cap adapter or transition spool 600 is shown. In general, transition spool 600 functions to transition between

the connector and associated connector profile at the lower end of the containment cap (e.g., female receptacle 150b at end 222b) to the connection and associated connector profile at the landing site (e.g., riser adapter 145, LMRP mandrel 151, hub 150a of BOP 120, or hub 150a of wellhead 130). In this embodiment, transition spool 600 includes an upper portion or spool 610 and a lower portion or spool 620 coupled to upper spool 610. Upper spool 610 has a central axis 615, a first or upper end 610a, and a second or lower end 610b. In addition, upper portion 610 includes a connector 611 at upper end 610a, an annular flange 613 at lower end 610b, and a tubular body 612 extending axially from connector 611 to flange 613. A through bore 614 extends axially through spool 610 from upper end 610a to lower end 610b. Flange 613 includes an annular planar facing surface 616 having an annular groove 617 and a plurality of circumferentially-spaced holes 618 extend axially therethrough. Connector 611 at upper end 610a is configured to mate and sealingly engage with the containment cap. Thus, for connection to containment cap 200, 400 previously described, connector 611 is a hub 150a configured to mate and sealingly engage complementary receptacle 150b at lower end 222b of containment cap 200, 400.

[00157] Lower spool 620 has a central axis 625, a first or upper end 620a, and a second or lower end 620b. In addition, lower portion 620 includes an annular flange 621 at upper end 620a, a connector 624 at lower end 620b, a frustoconical body 622 extending axially from flange 621, and a tubular body 623 extending from body 622 to connector 624. A through bore 626 extends axially through spool 620 from upper end 620a to lower end 620b. Flange 621 is configured the same as flange 613 previously described. In particular, flange 621 includes an annular planar facing surface 627 having an annular groove (not shown) and a plurality of circumferentially-spaced holes 629 extend axially therethrough. Connector 624 at lower end 620b is configured to mate and sealingly engage with a complementary connector on the landing site (e.g., riser adapter 145, LMRP mandrel 151, BOP 120, wellhead 130). Due to the number of possible connectors across the various landing sites, connector 624 may comprise any one of a number of possible connectors described in more detail below. For connection to a flange at the landing site, connector 624 may comprise a mating flange including alignment pins to facilitate the alignment of the mating flanges.

[00158] To connect upper spool 610 to lower spool 620, an annular seal 630 formed of inconel or other suitable material is positioned in the annular grooves in facing surfaces 616, 627, spools 610, 620 are coaxially aligned, and flanges 613, 621 are pushed into engagement with each other. With holes 618, 629 aligned, threaded studs 631 and hex nuts 632 fasten together upper and lower spools 610, 620.

[00159] Referring now to Figures 36A-36N, different embodiments of adapters 600A-600N are shown. Each adapter 600A-600N includes an upper portion 610 as previously described and a lower portion 620A-620N, respectively. Thus, the same upper portion 610 is used in each adapter 600A-600N, upper portion 610 including connector 611 configured to mate and sealingly engage the complementary connector on the containment cap (e.g., receptacle 150b at lower end 222b of containment cap 200, 400). In these embodiments, connector 611 is a male H4 connector, as available from Cameron International Corp., having a connector profile configured to mate and sealingly engage with complementary female receptacle 150b at lower end 222b of containment cap 200, 400, which is a female H4 connector, as available from GE Oil & Gas of Houston, Texas. Flange 613 is an 18 $\frac{3}{4}$ in. API flange. Each lower portion 620A-620L is the same as lower spool 620 previously described with the exception that the connector 624A-624L, respectively, at each lower end 620b is different to accommodate a different mating connector 650A-650L, respectively, at the landing site 651A-651L, respectively. Lower portion 620M, 620N simply comprises a connector 624M, 624N, respectively, that is directly connected to flange 613 of upper portion 610 with bolts. In other words, connectors 624M, 624N do not include a frustoconical body 622 or tubular body 623 as previously described. Connector 624M, 624N is different to accommodate a different mating connector 650M, 650N, respectively, at the landing site 651M, 651N, respectively. In general, connectors 650A-650L and corresponding landing sites 651A-651L described in more detail below are employed on riser adapters (e.g., riser adapter 145), whereas connectors 650M, 650N and corresponding landing sites 651M, 651N are employed on LMRPs (e.g., LMRP 130), BOPs (e.g., BOP 120), and wellheads (e.g., wellhead 130). Flange 621 of each lower spool 620A-620L is configured to mate and engage flange 613, and the upper end of each connector 624M, 624N is configured to mate and engage flange 613. Accordingly, since flange 613 is an 18 $\frac{3}{4}$ in. API flange, flange 621 of each lower spool 620A-620L is a mating 18 $\frac{3}{4}$ in. API flange, and the upper end of each connector 624M, 624N is configured to mate with an 18 $\frac{3}{4}$ in. API flange.

[00160] In Figure 36A, connector 624A of lower portion 620A is a female CLIP™ connector, as available from Aker-Kvaerner, having a connector profile configured to mate and sealingly engage with complementary connector 650A, which is a male CLIP™ connector, as available from Aker-Kvaerner. In Figure 36B, connector 624B of lower portion 620B is a female Load King™ connector, as available from Cameron International Corp., having a connector profile configured to mate and sealingly engage with complementary connector 650B, which is a male Load King™ connector, as available from Cameron International Corp. In Figure 36C,

connector 624C of lower portion 620C is a male HMF-F connector, as available from Vetco Gray, Inc., having a connector profile configured to mate and sealingly engage with complementary connector 650C, which is a female HMF-F connector, as available from Vetco Gray, Inc. In Figure 36D, connector 624D of lower portion 620D is a male MR-6H connector, as available from Vetco Gray, Inc., having a connector profile configured to mate and sealingly engage with complementary connector 650D, which is a female MR-6H connector, as available from Vetco Gray, Inc. In Figure 36E, connector 624E of lower portion 620E is a female MR-6C connector, as available from Vetco Gray, Inc., having a connector profile configured to mate and sealingly engage with complementary connector 650E, which is a male MR-6C connector, as available from Vetco Gray, Inc. In Figure 36F, connector 624F of lower portion 620F is a female MR-6D connector, as available from Vetco Gray, Inc., having a connector profile configured to mate and sealingly engage with complementary connector 650F, which is a male MR-6D connector, as available from Vetco Gray, Inc. In Figure 36G, connector 624G of lower portion 620G is a male HMF-G connector, as available from Vetco Gray, Inc., having a connector profile configured to mate and sealingly engage with complementary connector 650G, which is a female HMF-G connector, as available from Vetco Gray, Inc. In Figure 36H, connector 624H of lower portion 620H is a male HMF-D connector, as available from Vetco Gray, Inc., having a connector profile configured to mate and sealingly engage with complementary connector 650H, which is a female HMF-D connector, as available from Vetco Gray, Inc. In Figure 36I, connector 624I of lower portion 620I is a male HMF-E connector, as available from Vetco Gray, Inc., having a connector profile configured to mate and sealingly engage with complementary connector 650I, which is a female HMF-E connector, as available from Vetco Gray, Inc. In Figure 36J, connector 624J of lower portion 620J is a female FT-GB connector, as available from National Oilwell Varco, Inc. of Houston, Texas, having a connector profile configured to mate and sealingly engage with complementary connector 650J, which is a male FT-GB connector, as available from National Oilwell Varco, Inc. of Houston, Texas. In Figure 36K, connector 624K of lower portion 620K is a male RD connector, as available from Cameron International Corp., having a connector profile configured to mate and sealingly engage with complementary connector 650K, which is a female RD connector, as available from Cameron International Corp. In Figure 36L, connector 624L of lower portion 620L is a female DT-2 connector, as available from Shafer, having a connector profile configured to mate and sealingly engage with complementary connector 650L, which is a male DT-2 connector, as available from Shafer. In Figure 36M, connector 624M is a female SHD H4 connector, as available from Cameron International Corp., having a

connector profile configured to mate and sealingly engage with complementary connector 650M, which is a male SHD H4 connector, as available from Cameron International Corp. In Figure 36N, connector 624N of lower portion 620N is a female HC connector, as available from Cameron International Corp., having a connector profile configured to mate and sealingly engage with complementary connector 650N, which is a male HC connector, as available from Cameron International Corp.

[00161] As will thus be understood, a single containment cap (e.g., cap 200, 400) can be employed so as to shut in and contain a well by placement of the cap at any one of four locations (on the well head 130, on the BOP 120, on the mandrel 151 of LMRP 140, or on the riser adapter 145). This may be accomplished by maintaining an inventory of multiple transition spools 600, with such transition spools 600 having identical upper portions 610 and differing lower portions 620 to accommodate different landing sites. As used herein, the term “inventory” when used as a noun means a collection of goods held in stock. Similarly, the word “inventory” when used as a verb and the phrase “maintaining an inventory” mean keeping the collection of goods on hand and ready for disposition. For a given well, the connector profiles of wellhead, the BOP, the mandrel of LMRP and of the riser adapter are all known such that the proper transition spool(s) 600 may be maintained at the surface vessel or drilling rig 110, or at a more distant storage facility. For example, a storage facility can be used for housing and maintaining one of each type of transition spool 600 that might be necessary for use with all the wells in a given region, such as the Gulf of Mexico. The inventory would include, in addition to the appropriate transition spools 600, at least one containment cap 200, 400 (preferably stored in its modular form). Should a well blowout occur, the modular components of the containment cap, as well as the transition spools necessary may be identified, selected from the inventory, and shipped expeditiously to the well site for use in capping the well.

[00162] Referring to Figure 37, a storage facility 700 is schematically represented and houses lower assembly 210, upper assembly 250, and kill-flow back assembly 290, each as previously described, in a condition to be readily shipped and assembled into containment cap 200. Also maintained in inventory within storage facility 700 is at least one of each of a plurality of adapters 600 (e.g., one or more of adapters 600A-600N) as might be needed to connect containment cap 200 to any well head, BOP, LMRP mandrel, or riser adapter in the geographic region for which the storage facility 700 is dedicated to serve. For each well in that geographic region, it will be known the type and configuration of well head, BOP, LMRP, mandrel and riser adapter. In this example, adapters 600A-600F, 600M, and 600N comprise all the adapters

necessary to attach cap 200 to each of the wellhead, BOP, LMRP mandrel, and riser adapter for each well in the region. However, it should be appreciated that any combination of adapters 600A-600N (or other transition spools including different connectors) can be included in facility 700 depending on the structures of the wellheads, BOPs, LMRP mandrels, and riser adapters in the geographic region of interest. Should a subsea blowout occur, the information about the well and its structures (e.g., wellhead, BOP, LMRP mandrel, and riser adapter) is transmitted to service personnel maintaining the equipment in storage in storage facility 700. Alternatively, the service personnel may have information at hand and be able to “look up” information as to the type and configuration of all equipment at each well. Once that information is known, the appropriate adapter(s) 600 necessary (e.g., necessary to connect the containment cap 200 to a specific well component or components) is selected, and deployed for transportation to the well site along with containment cap assemblies 210, 250, 290 in order to cap and contain the well. Having the modular containment cap assemblies (e.g., assemblies 210, 250, 290) and all possible adapters (e.g., adapters 600A-600F, 600M, and 600N) in inventory and ready for shipment may provide a faster and more efficient means for capping a subsea well and may lessen potential environmental impact and damage. Although storage facility 700 shown in Figure 37 includes the components of containment cap 200 (e.g., lower assembly 210, upper assembly 250, and kill-flow back assembly 290), in other embodiments, the storage facility (e.g., facility 700) may alternatively include the components of containment cap 400 previously described (e.g., lower assembly 210, valve assembly 450, and cap 470).

[00163] Referring now to Figure 38, another storage facility 800 is schematically represented and houses lower assembly 210, upper assembly 250, and kill-flow back assembly 290 of containment cap 200, each as previously described. Further, an inventory is maintained in facility 800 including at least one upper portion 610 (two being shown in this example) and each lower portion 620A-620F, 620M, and 620N of adapters 600A-600F, 600M, and 600N needed to service the wells in the designated region. Again, it is to be understood that lower portions 620A-620F, 600M, and 600N of adapter 600A-600F, 600M, and 600N, respectively, are merely examples of possible transition spool lower portions. In general, any combination of lower portions 620A-620N (or other lower portions including different connectors) can be included in facility 800 depending on the structures of the wellheads, BOPs, LMRP mandrels, and riser adapters in the geographic region of interest. Because upper portion 610 of each adapter 600A-600F, 600M, and 600N is identical in these embodiments, it is not necessary to inventory an upper portion 610 for each of the adapter 600A-600F, 600M, and 600N. Instead, upon the need arising, the appropriate lower portion 620A-620F, 620M, 620N can be selected

and attached to the upper portion 610 as previously described. Although some additional time is required to make this connection, it is one that is not overly time-consuming and can save the cost of manufacturing, maintaining and storing multiple upper portions 610 for each adapter 600A-600F, 600M, and 600N. Although storage facility 800 shown in Figure 38 includes the components of containment cap 200 (e.g., lower assembly 210, upper assembly 250, and kill-flow back assembly 290), in other embodiments, the storage facility (e.g., facility 800) may alternatively include the components of containment cap 400 previously described (e.g., lower assembly 210, valve assembly 450, and cap 470).

[00164] 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 method for controlling hydrocarbons flowing from a subsea structure, comprising:
lowering an adapter from the surface to a subsea structure, the adapter having a through bore extending between an upper connector having a first connector profile and a lower connector having a second connector profile that is different than the first connector profile;
coupling the lower connector of the adapter to the subsea structure;
lowering a containment cap from the surface to the adapter; and
coupling the containment cap to the upper connector of the adapter.
2. The method of claim 1, further comprising:
maintaining an inventory comprising a plurality of adapters, at least some of the plurality of adapters including an upper connector with an upper connector profile configured to mate with the containment cap and a lower connector with a lower connector profile that is different from the upper connector profile and different from the lower connector profile of at least some of the other adapters.
3. The method of claim 2, further comprising choosing from the inventory the adapter with the lower connector having the lower connector profile configured to mate with a connector on a landing site on the subsea structure.
4. The method of claim 3, wherein the landing site is a riser adapter of a subsea flex joint, a mandrel of a lower marine riser package, a blowout preventer, or a wellhead.
5. The method of claim 2, further comprising coupling the upper connector to the lower connector.
6. The method of claim 1, further comprising:
maintaining an inventory comprising at least one upper connector and a plurality of lower connectors;
wherein each of the upper connectors has an upper connector profile configured to mate with the containment cap;

wherein each of the lower connectors has a lower connector profile that is different from the upper connector profile and different from the lower connector profile of at least some of the other lower connectors.

7. A method of capping a subsea well comprising:

choosing from an inventory of adapters a selected adapter, the selected adapter having a lower connector with a lower connector profile configured to mate with a connector on a subsea structure and an upper connector with an upper connector profile that is different than the lower connector profile; and

connecting the lower connector of the selected adapter to the subsea structure.

8. The method of claim 7, further comprising coupling a containment cap to the upper connector of the selected adapter.

9. The method of claim 7, further comprising conducting a flow of hydrocarbons through the selected adapter.

10. The method of claim 8, further comprising coupling the containment cap to the selected adapter while hydrocarbons are flowing from the selected adapter into the containment cap.

11. The method of claim 7, wherein connecting the lower connector of the selected adapter to the subsea structure comprises connecting the lower connector of the selected adapter to a subsea riser adapter, a subsea LMRP, a subsea BOP, or a subsea wellhead.

12. A method of capping a subsea well, comprising:

maintaining an inventory comprising a plurality of adapters, each of the plurality of adapters having an upper connector with an upper connector profile and a lower connector with a lower connector profile that differs from the upper connector profile and that also differs from the lower connector profile of at least some of the other adapters of the plurality;

identifying the connector profile of a subsea connector on a subsea structure at a well that is discharging hydrocarbons into the surrounding sea water;

selecting from the inventory a select adapter that has the lower connector with the lower connector profile that is configured to mate with the subsea connector.

13. The method of claim 12, further comprising maintaining in the inventory a containment cap.
14. The method of claim 13, further comprising shipping the select adapter and the containment cap from the inventory to a vessel disposed at the sea surface generally above the subsea well.
15. The method of claim 13, further comprising coupling the select adapter to the subsea connector and coupling the containment cap to the adapter while hydrocarbons are being discharged from the subsea equipment.
16. An adapter for coupling a containment cap to a subsea structure, the adapter comprising:
a first portion 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 first connector having a first connector profile;
a second portion 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 second end comprises a second connector having a second connector profile that is different from the first connector profile.
17. The adapter of claim 16, wherein the second end of the first portion comprises an annular flange that is coupled to an annular flange at the first end of the second portion.
18. The adapter of claim 16, wherein the first connector is configured to mate and engage a connector of the subsea containment cap.
19. The adapter of claim 18, wherein the second connector is configured to mate and engage a connector on the subsea structure.
20. An apparatus for controlling a subsea wellbore, comprising:
a containment cap having a through bore and a valve adapted to close and prevent fluid flow through the through bore, and further comprising a connector at the lower end of the containment cap having a first connector profile;

an adapter comprising:

- an upper and a lower end and a through bore extending therebetween;
- a first connector at the upper end mated to and sealingly engaged with the connector of the containment cap;
- a second connector at the lower end adapted to mate and sealingly engage with a connector on a subsea structure other than the containment cap, the second connector of the adapter having a second connector profile that is different than the first connector profile.

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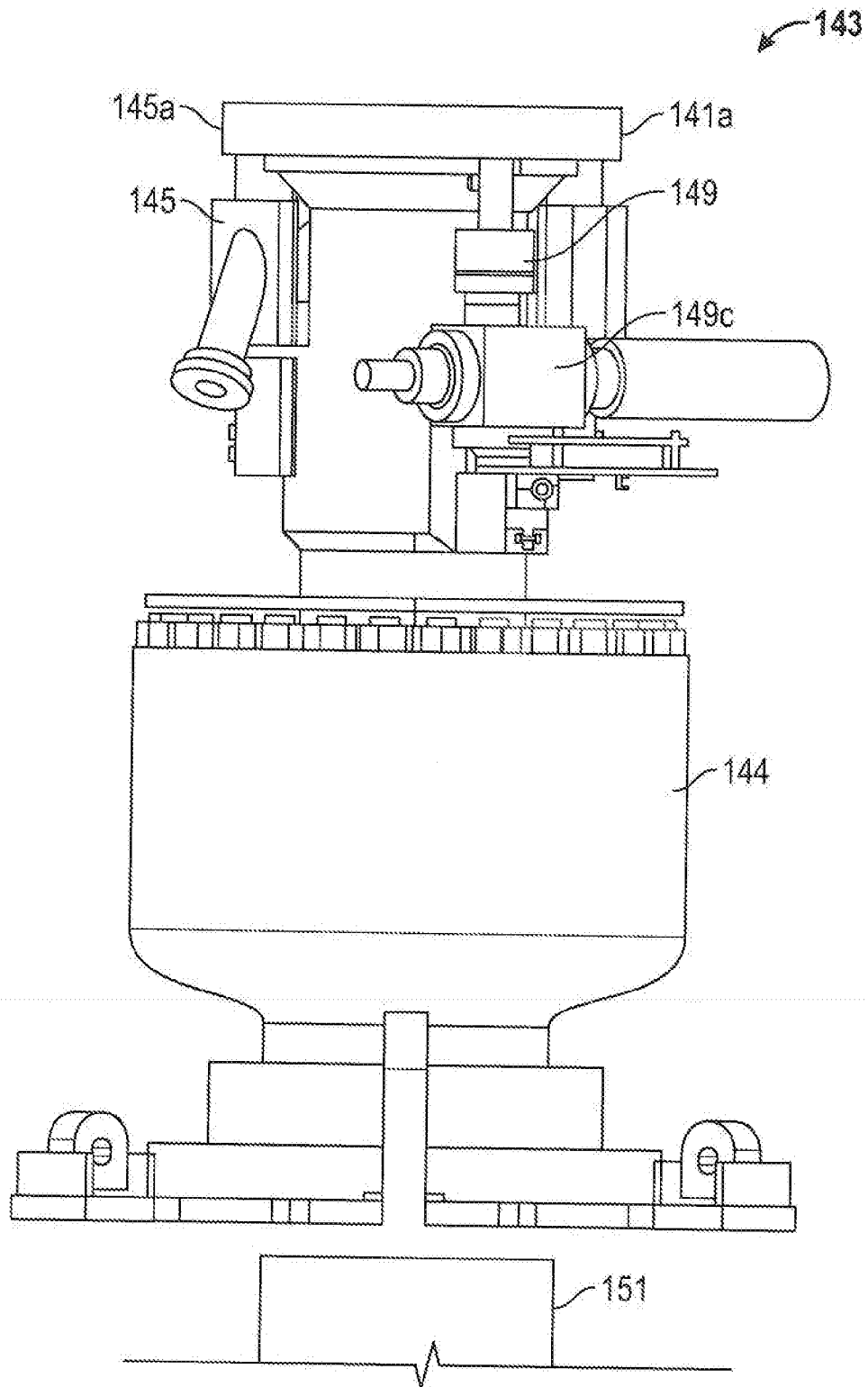


FIG. 2

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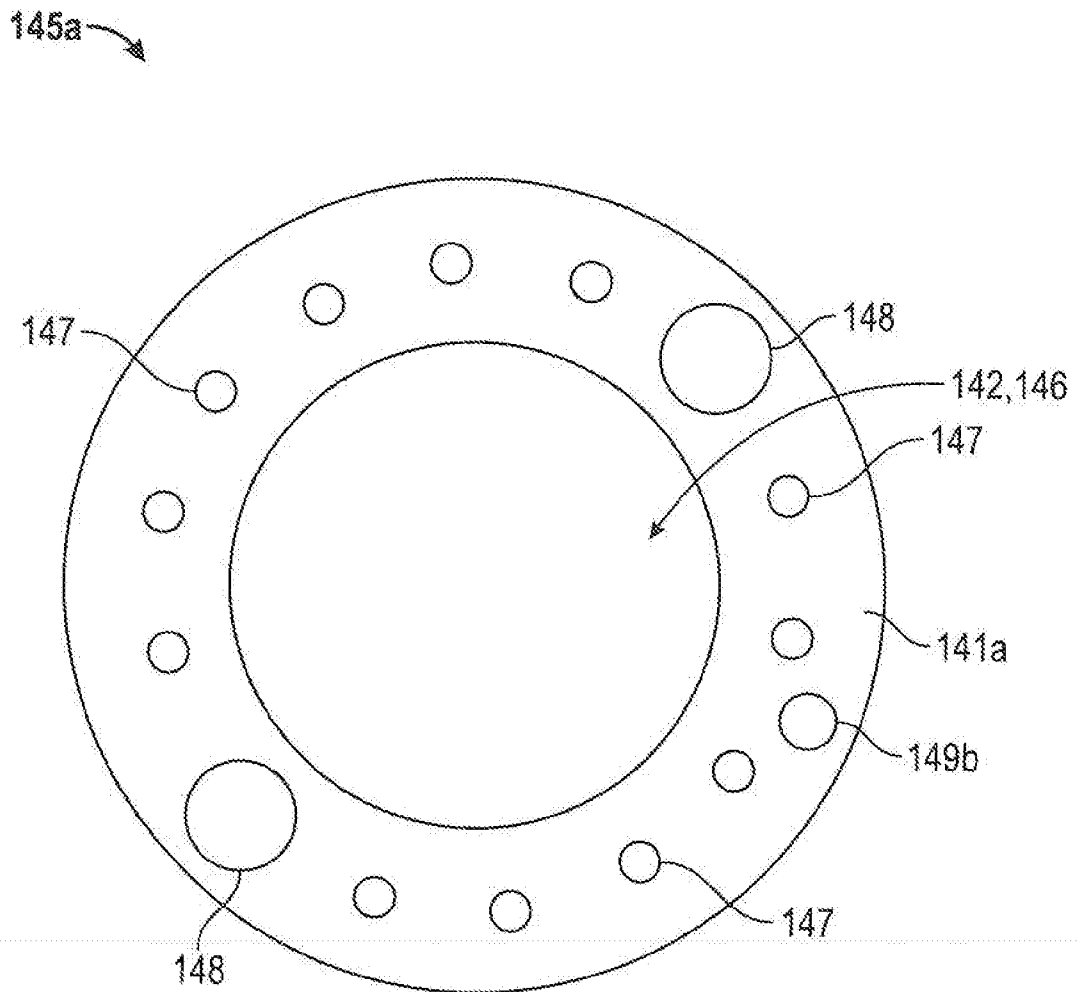


FIG. 3

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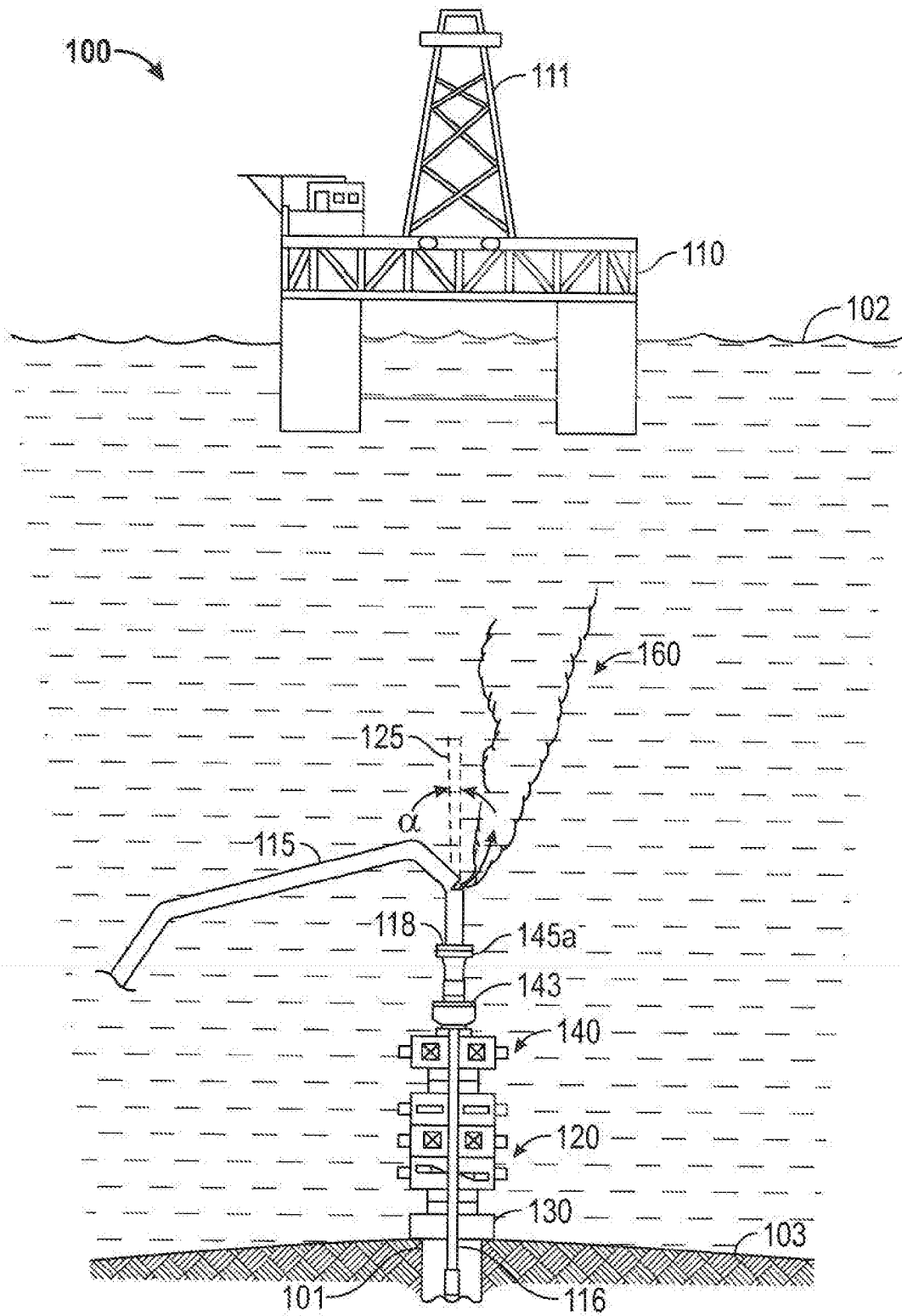


FIG. 4

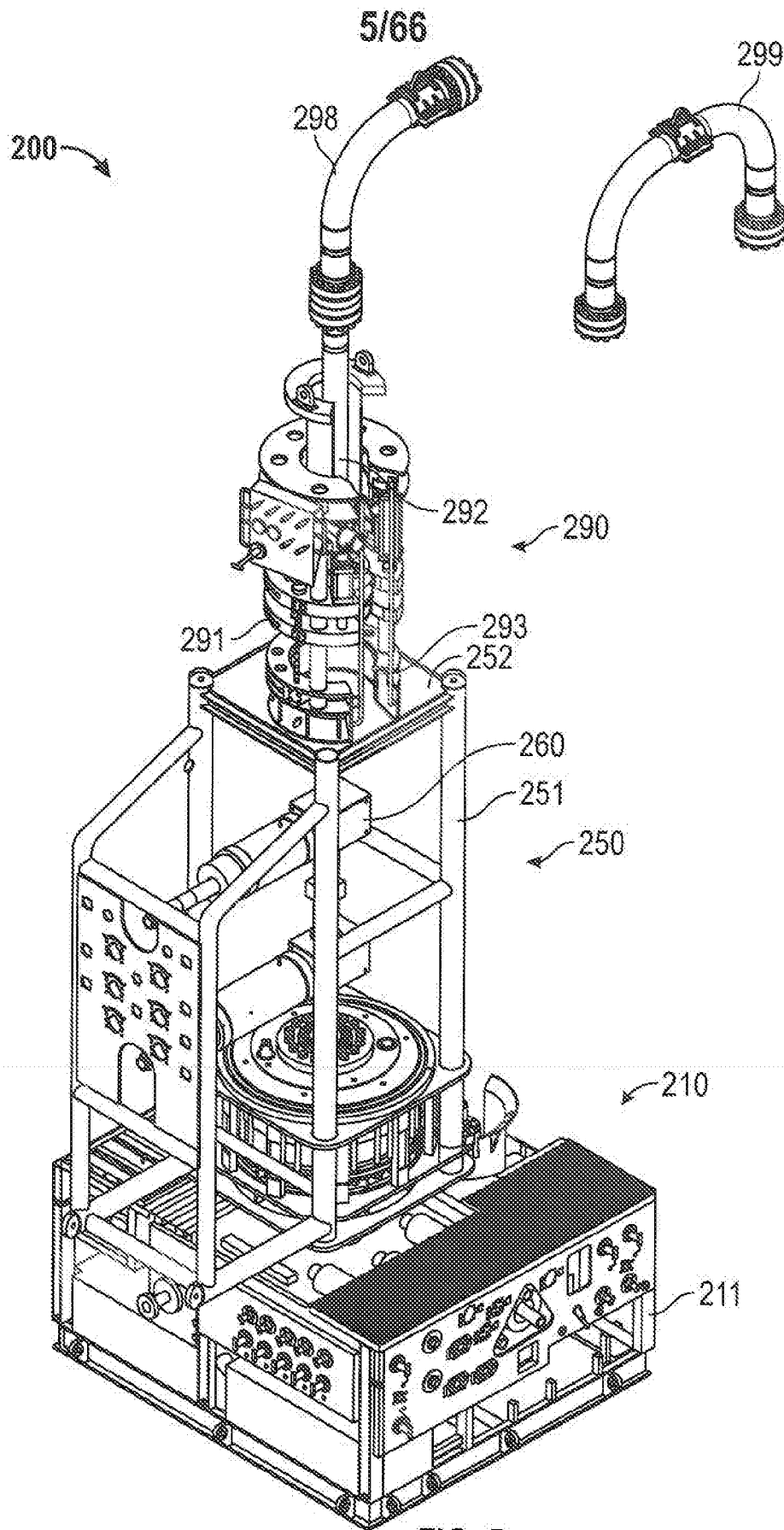


FIG. 5

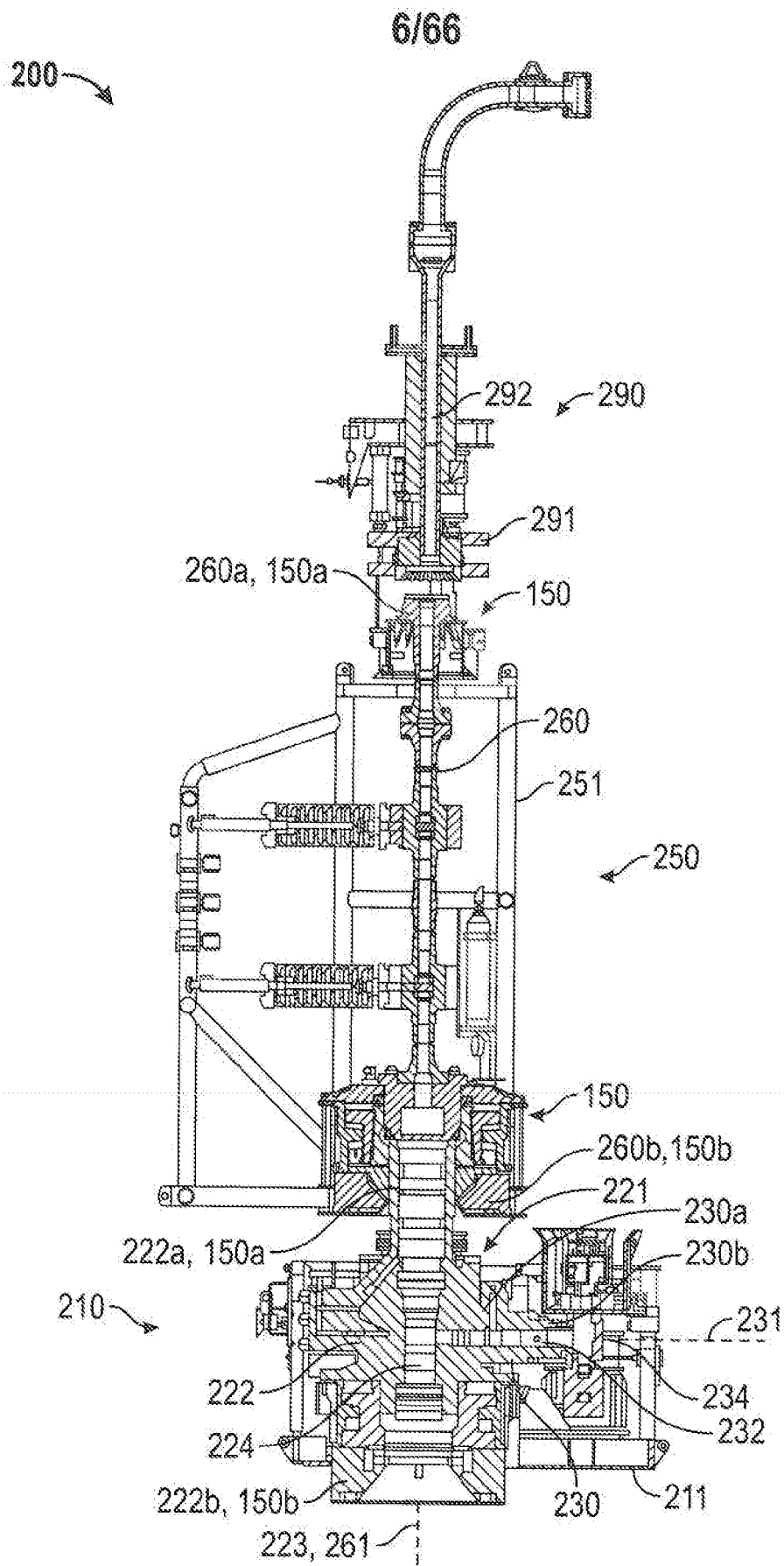


FIG. 6

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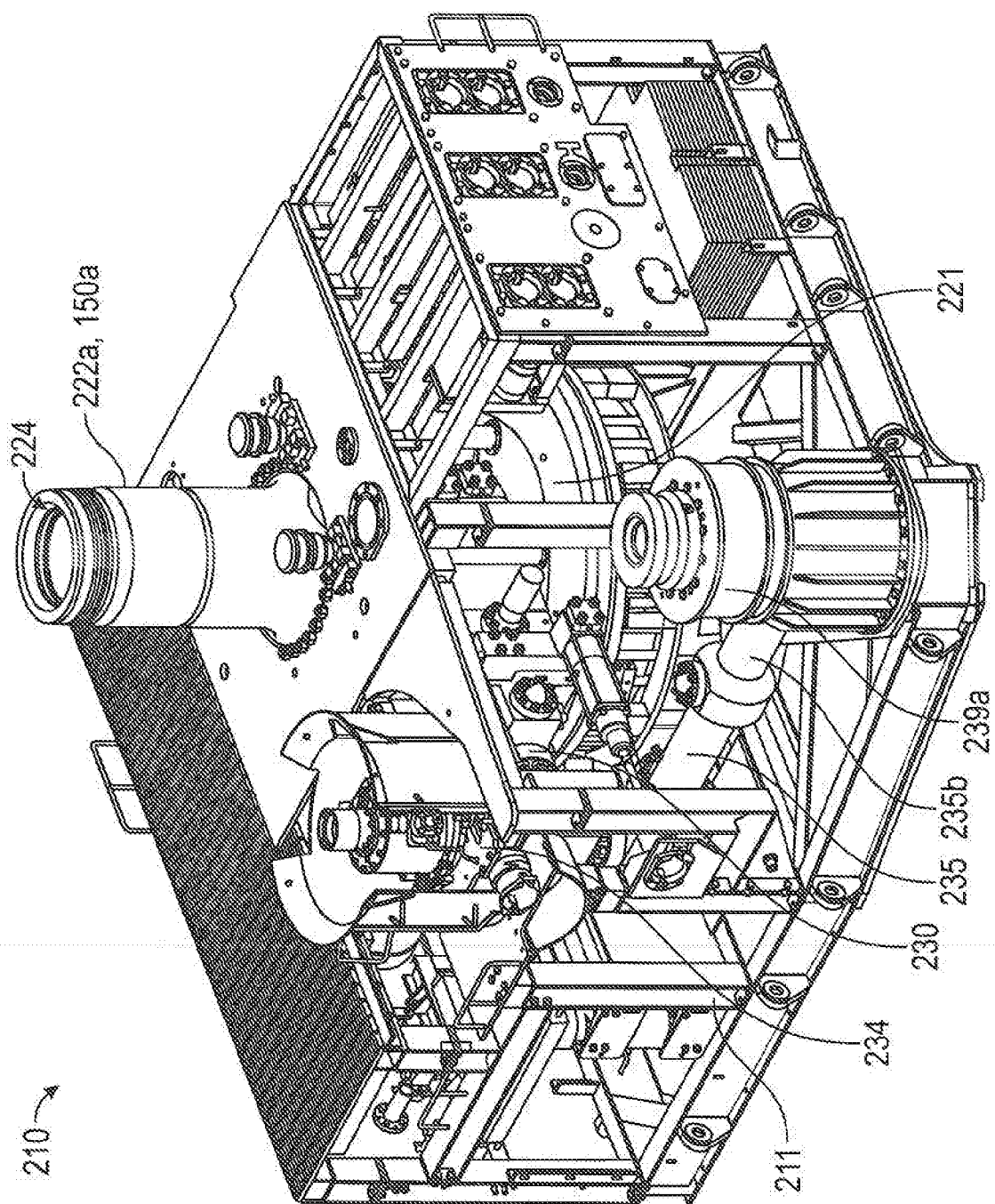


FIG. 7

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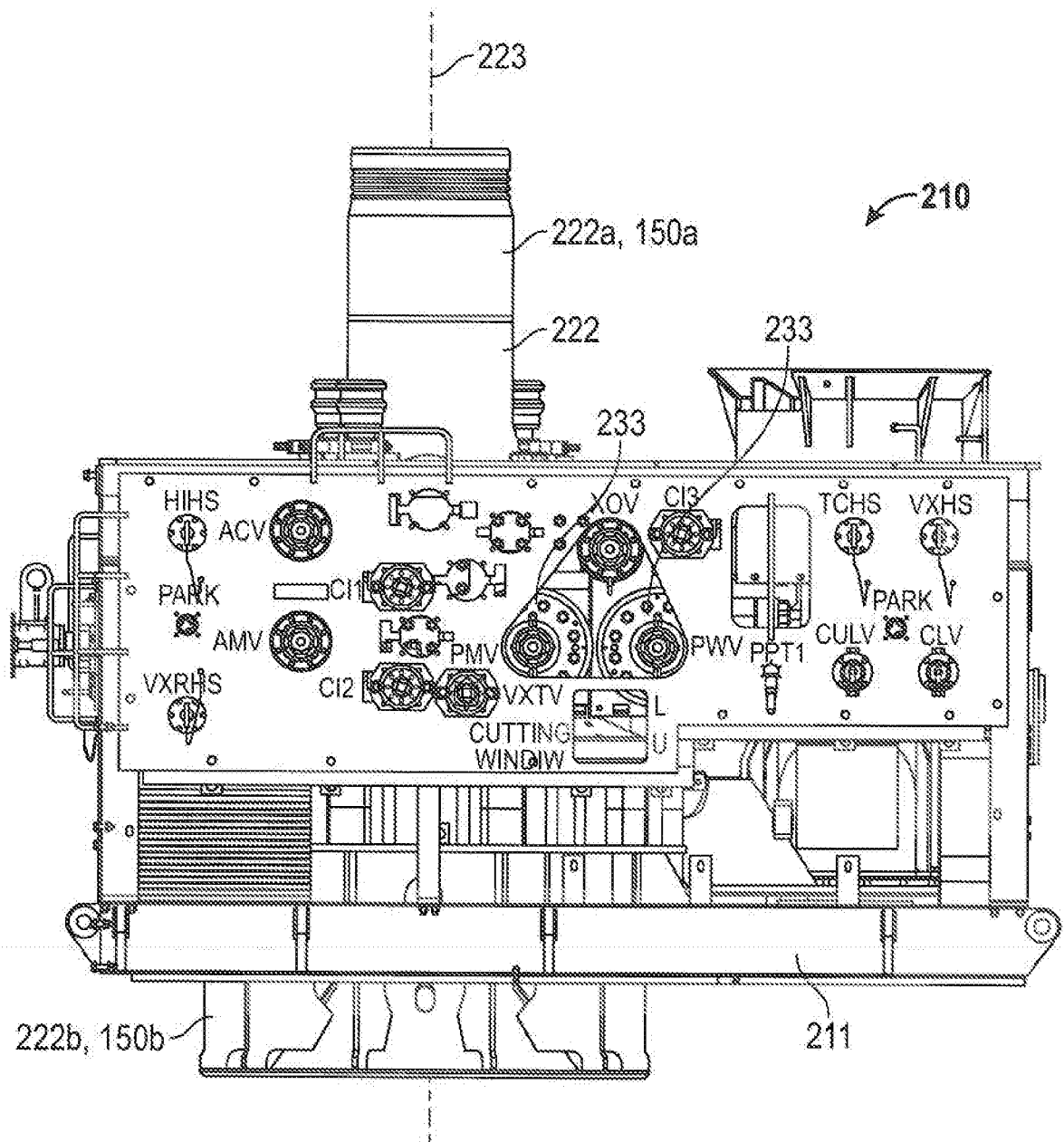


FIG. 8

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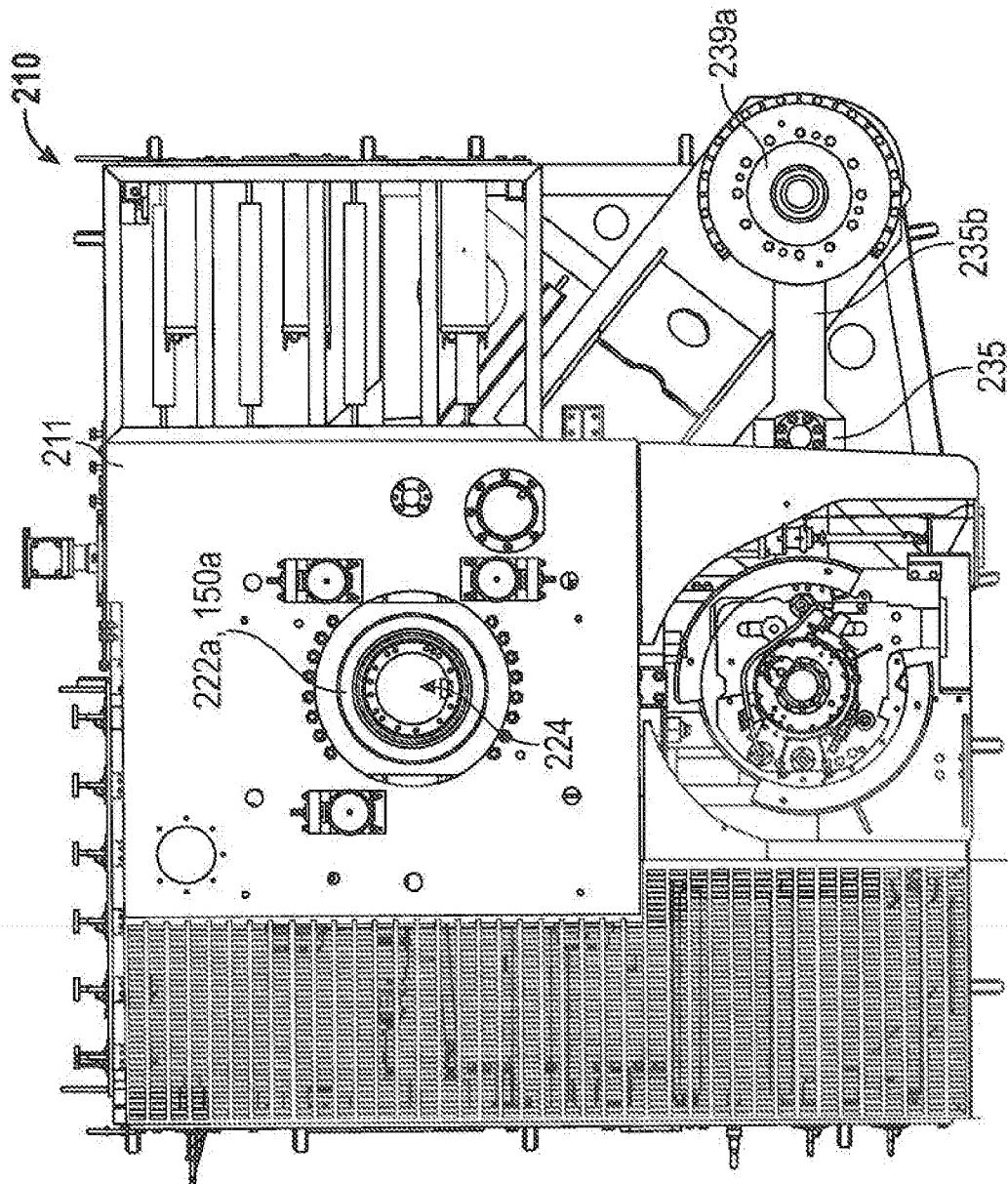
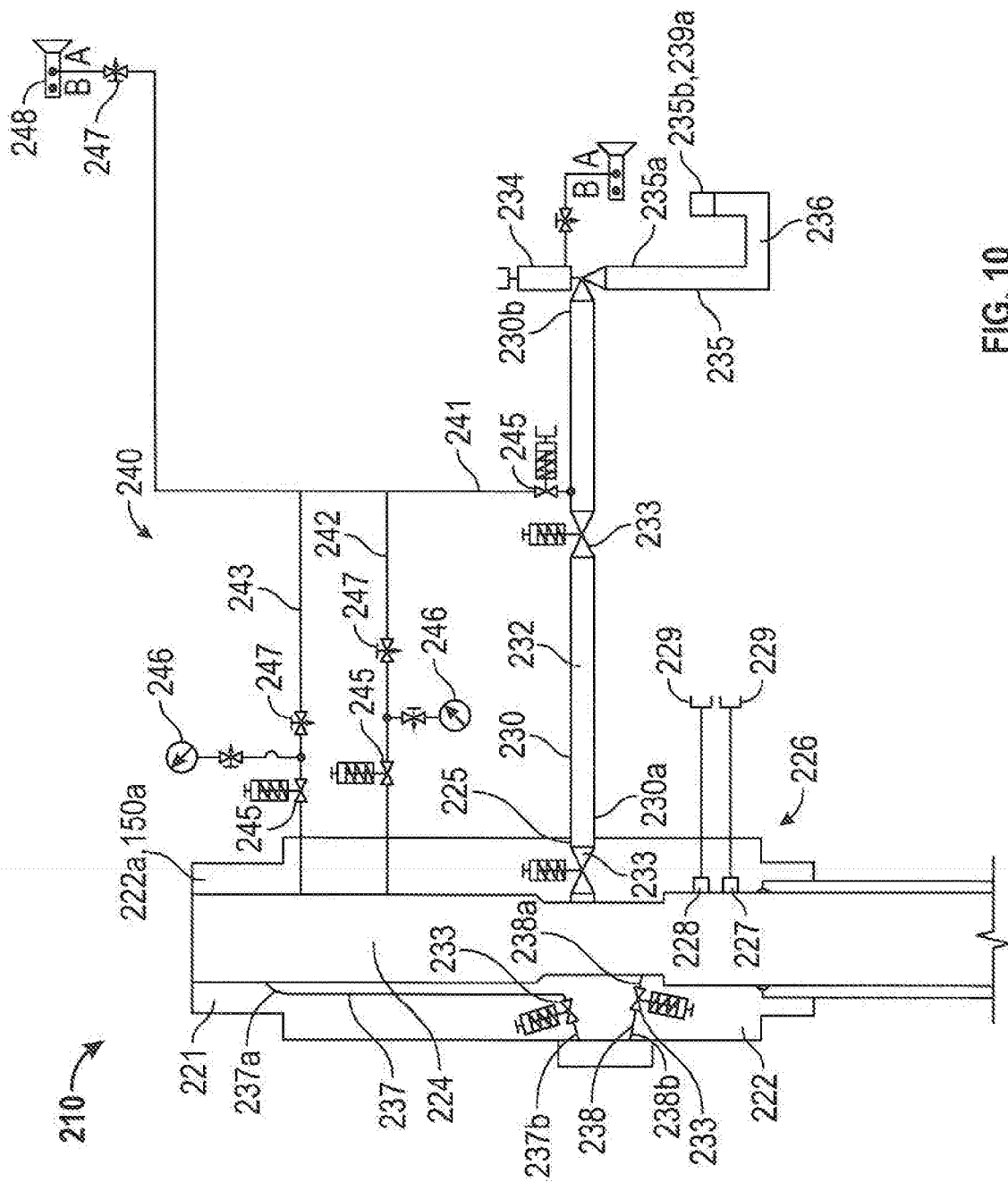


FIG. 9



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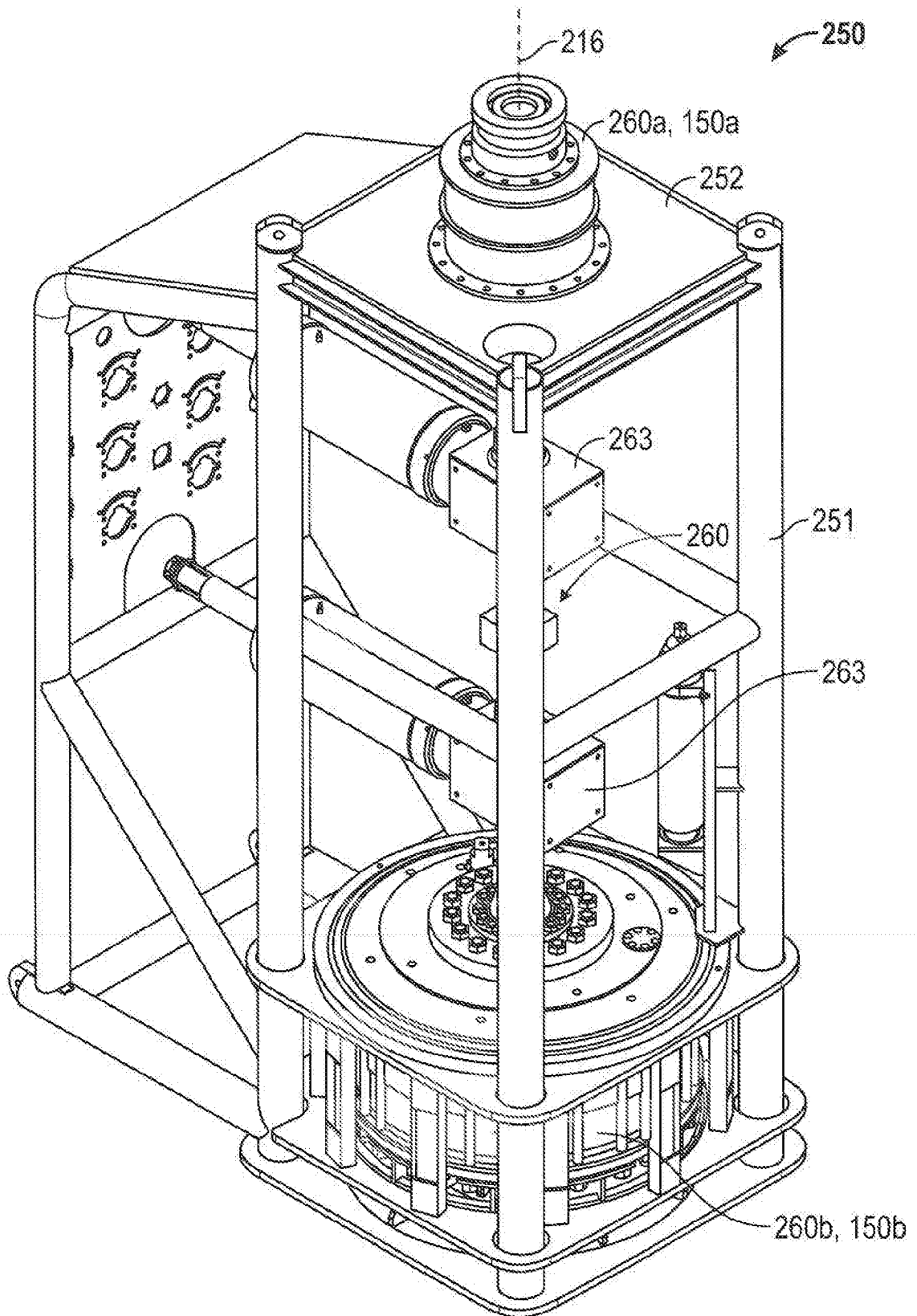


FIG. 11

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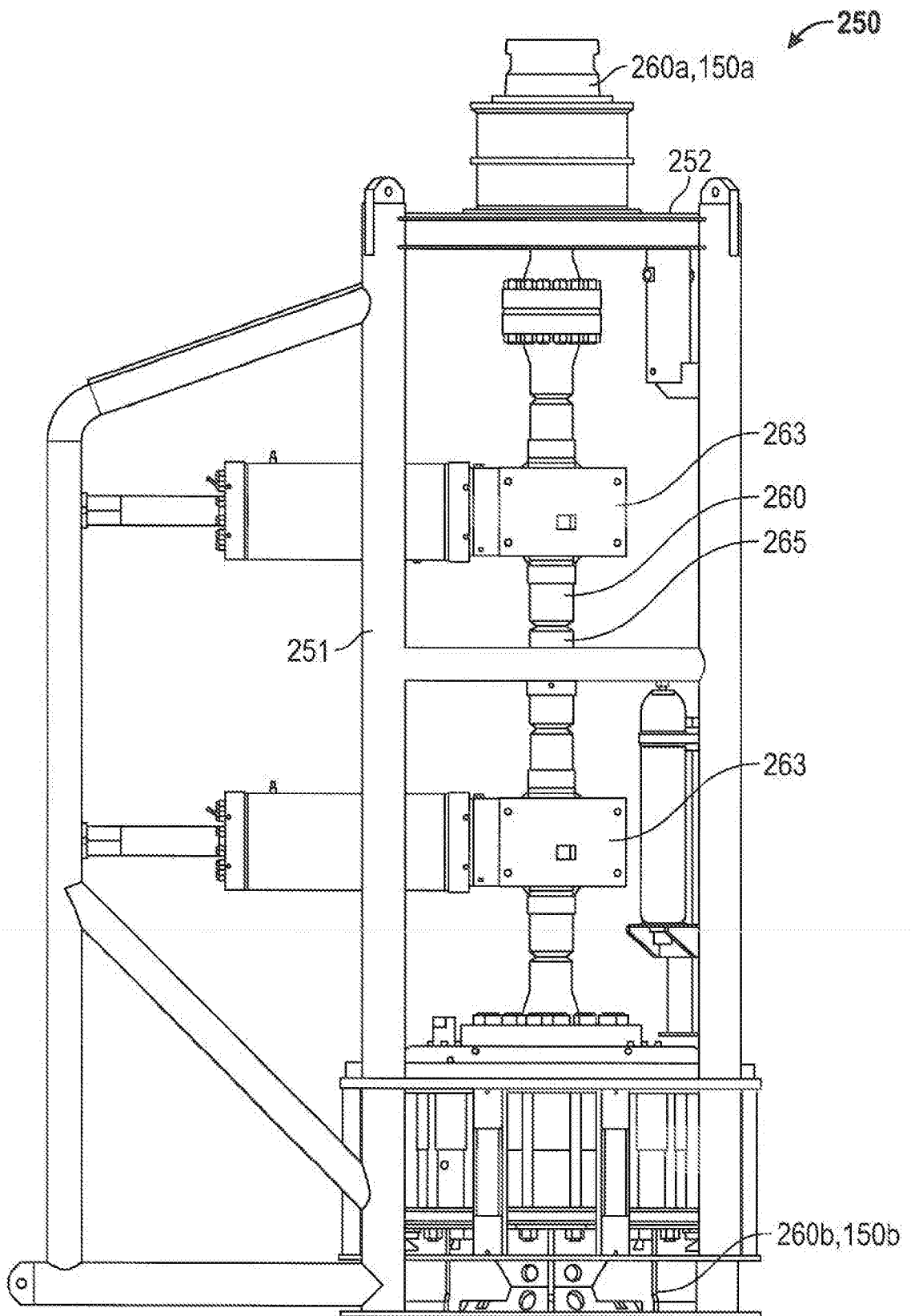


FIG. 12

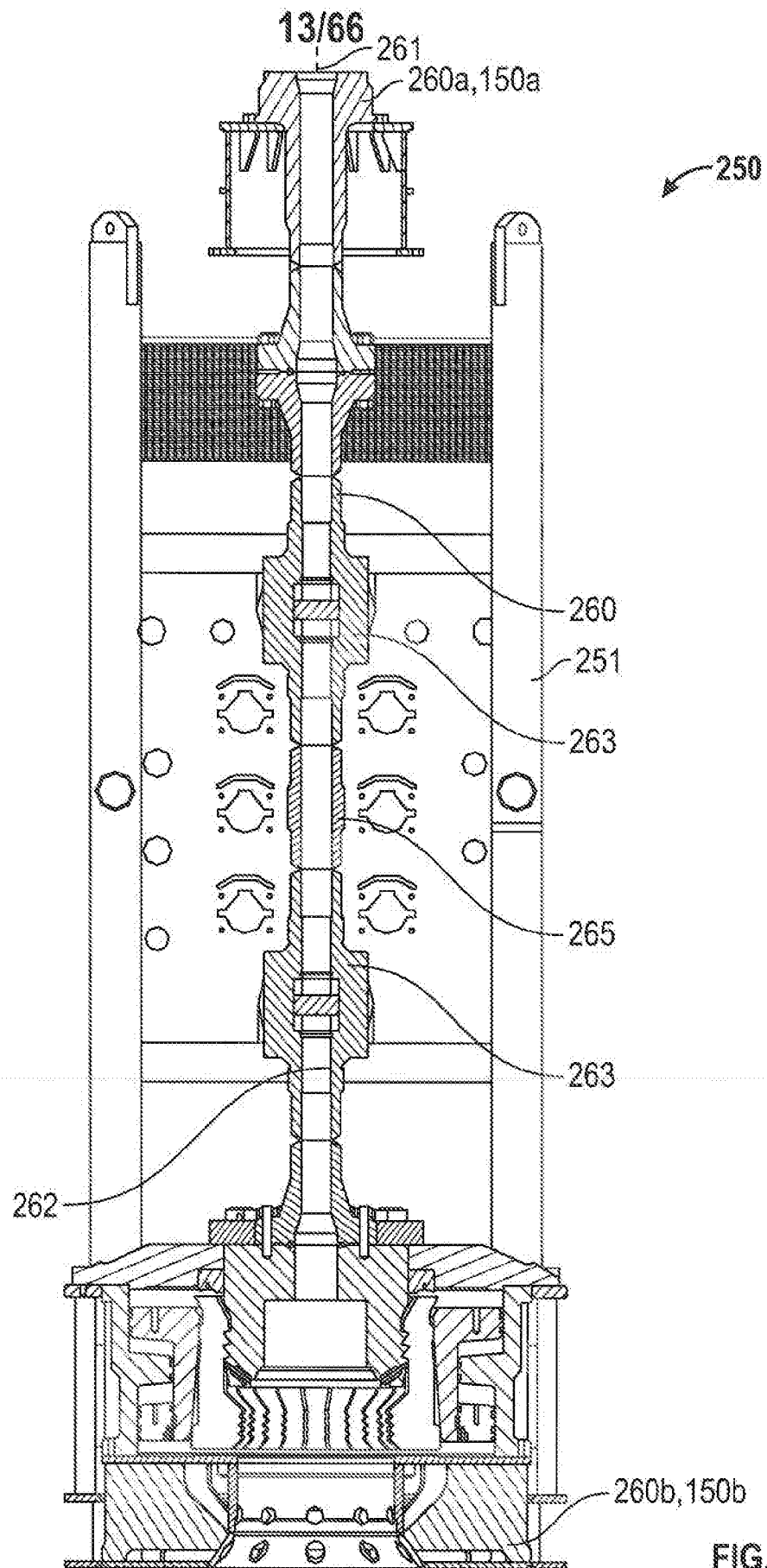


FIG. 13

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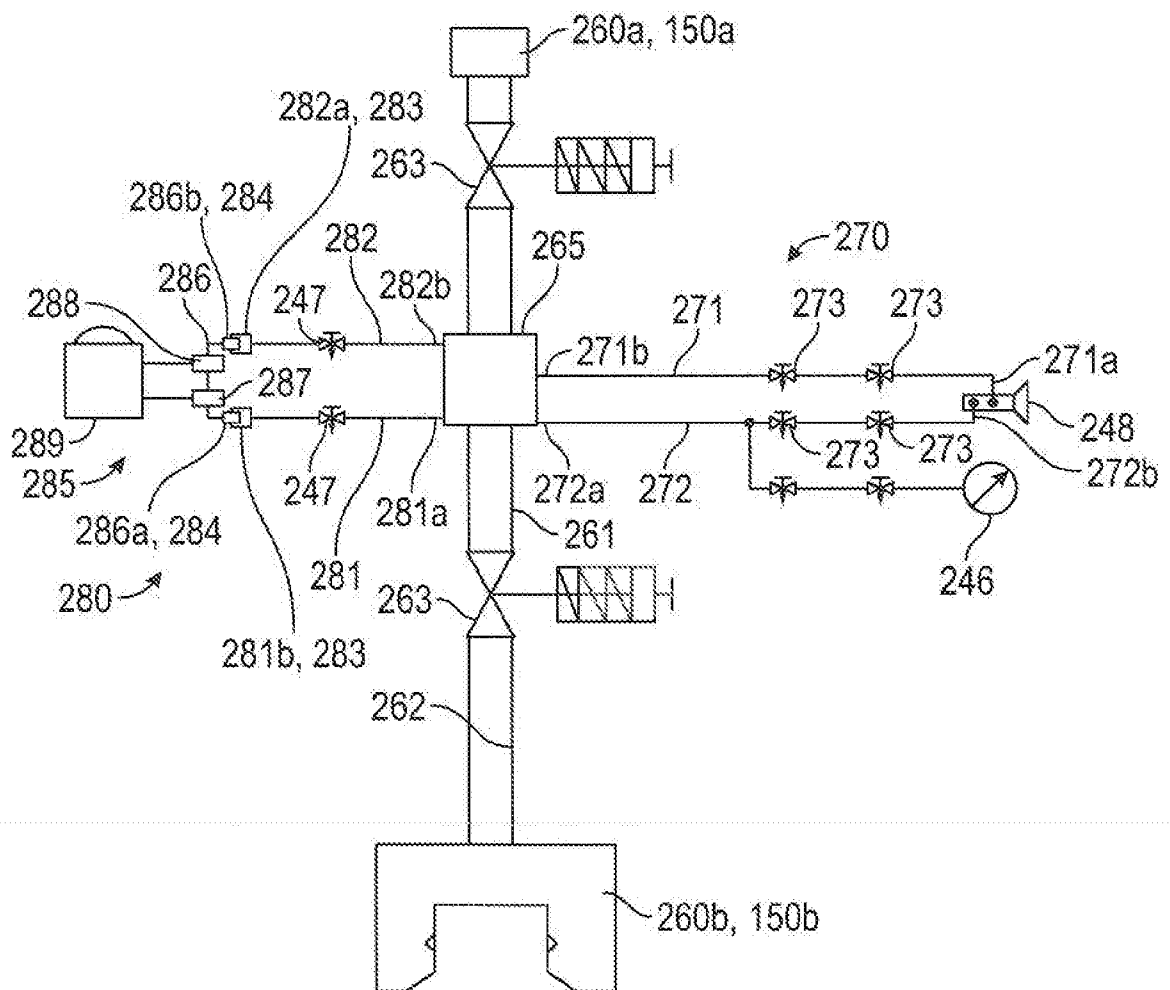


FIG. 14

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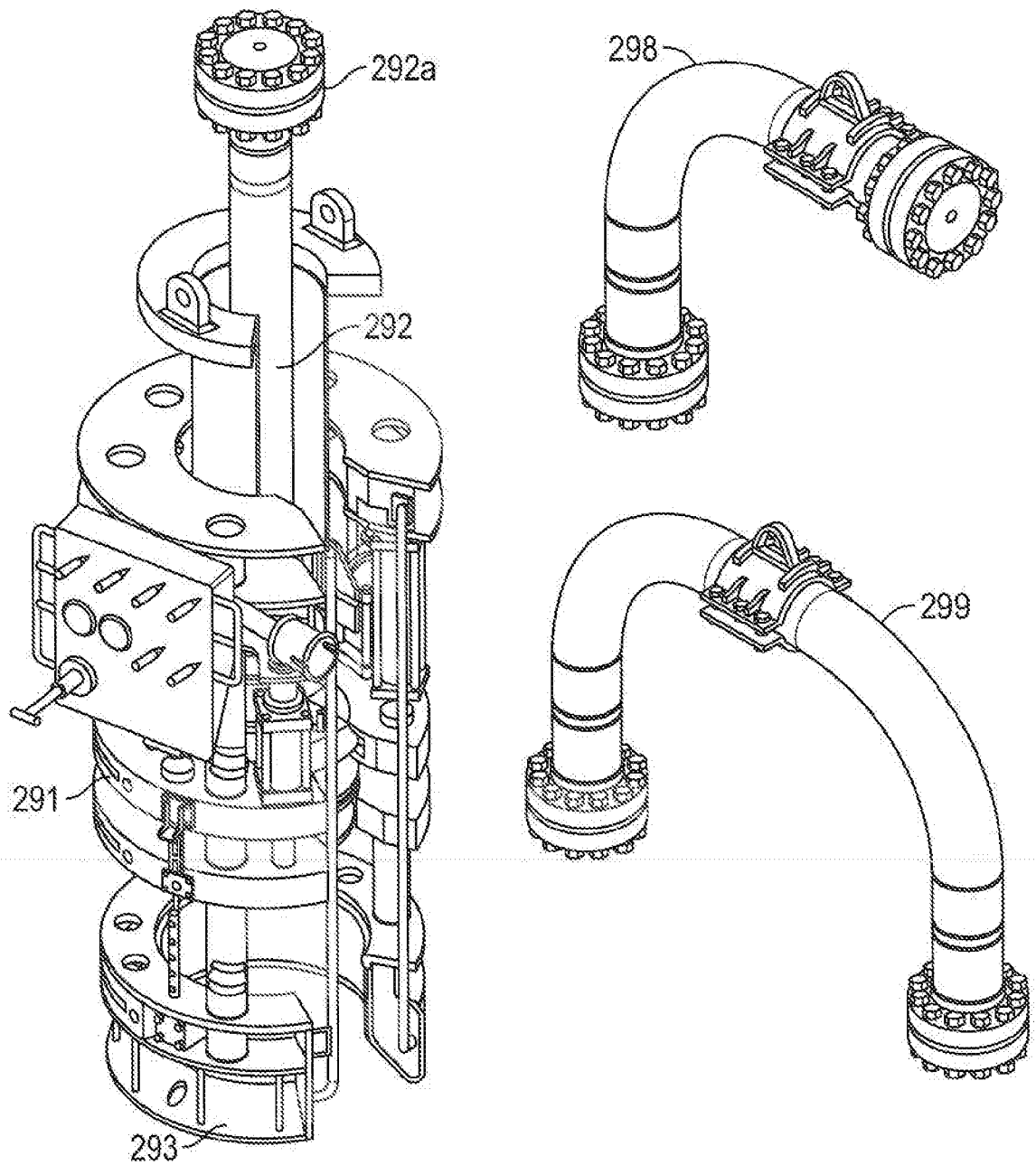


FIG. 15

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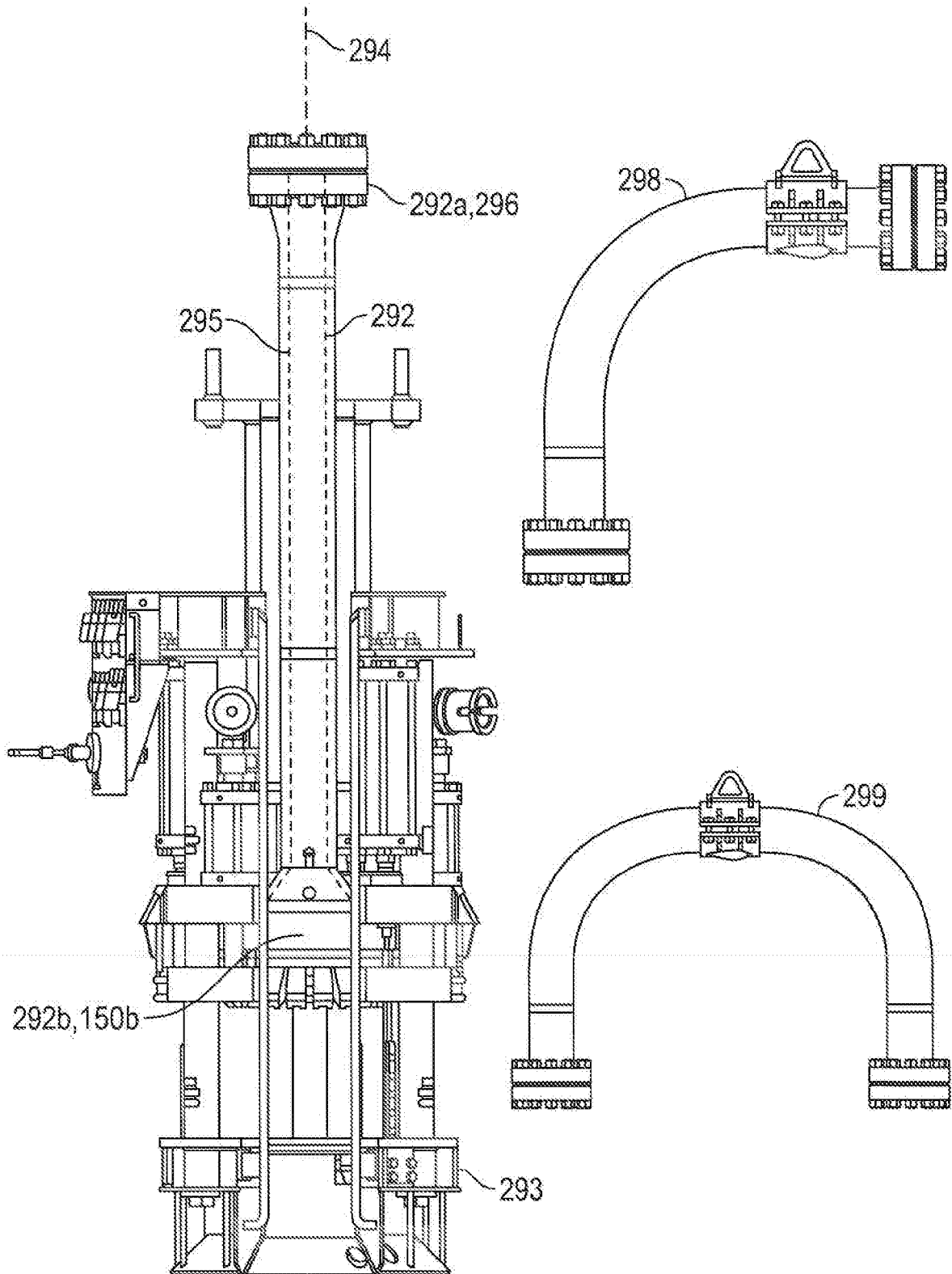


FIG. 16

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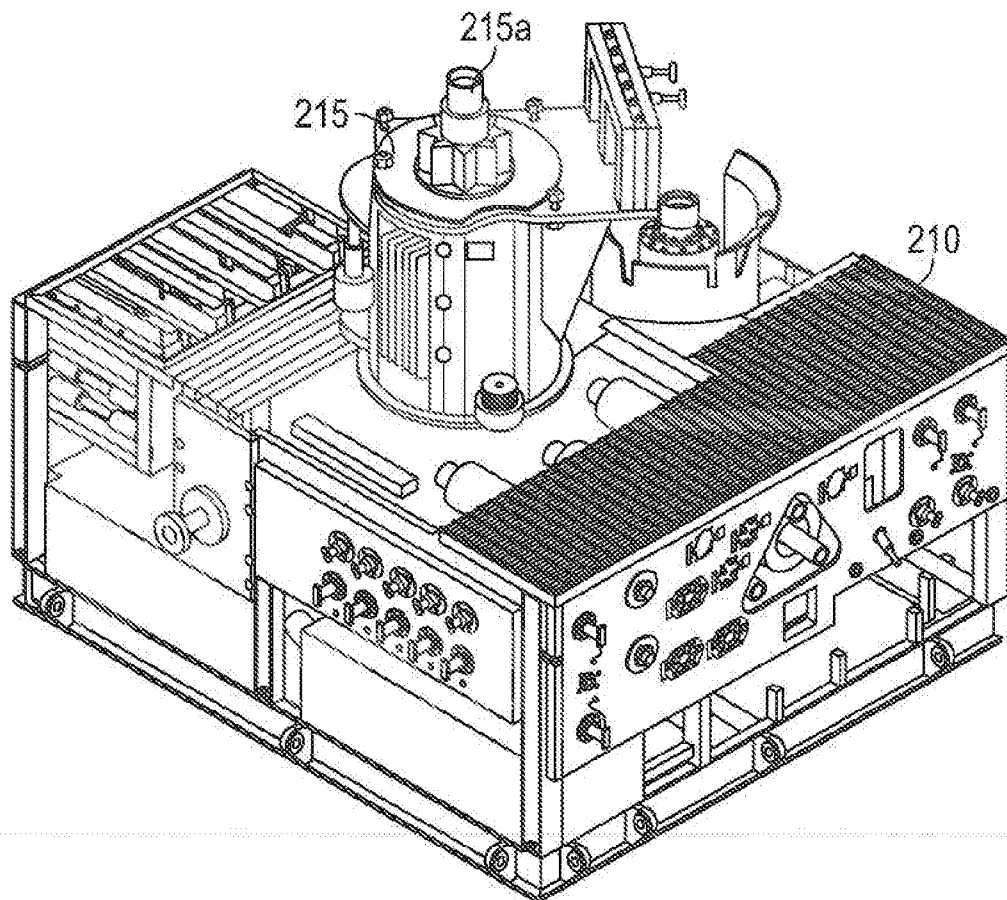


FIG. 17

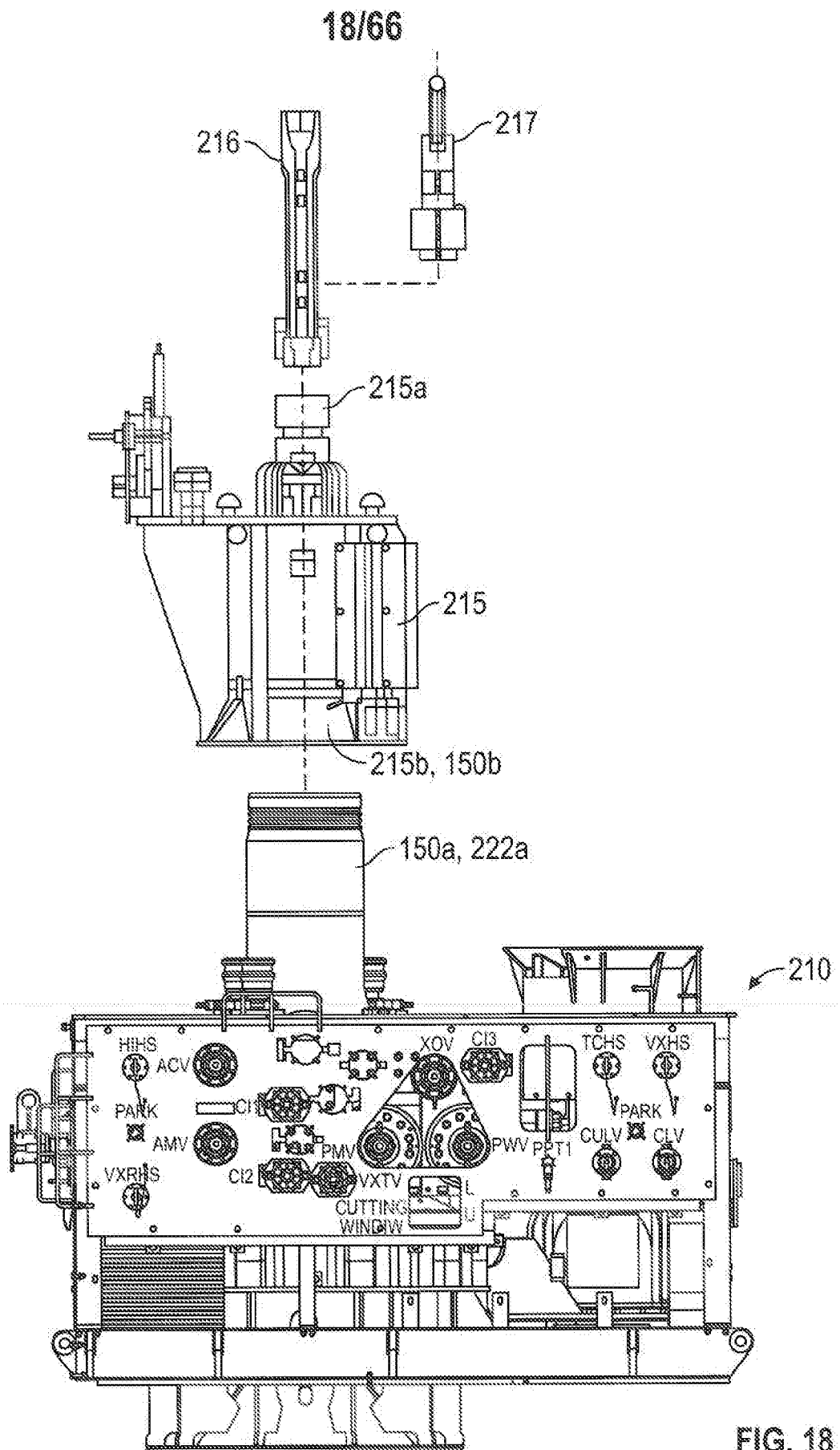


FIG. 18

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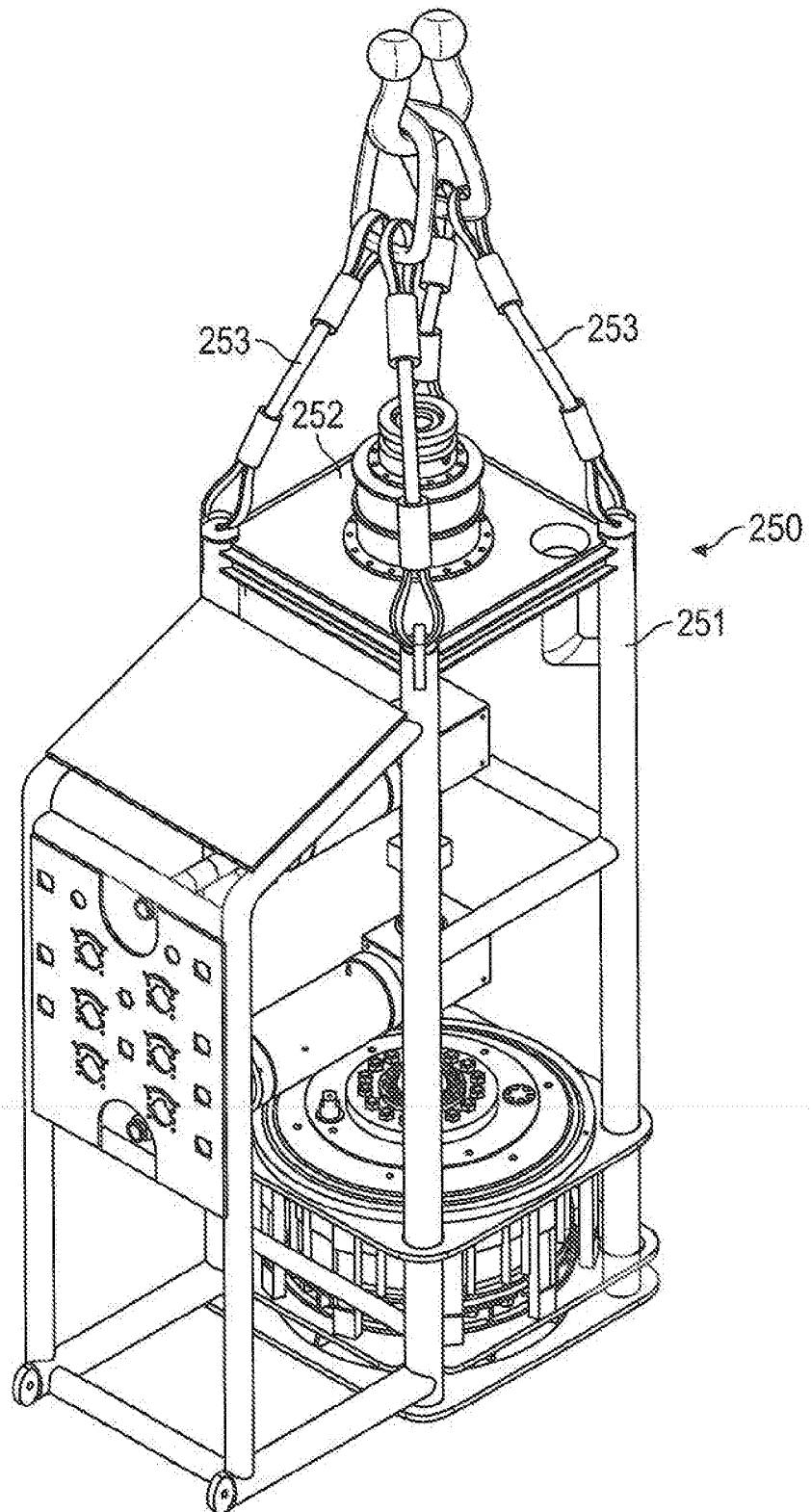


FIG. 19

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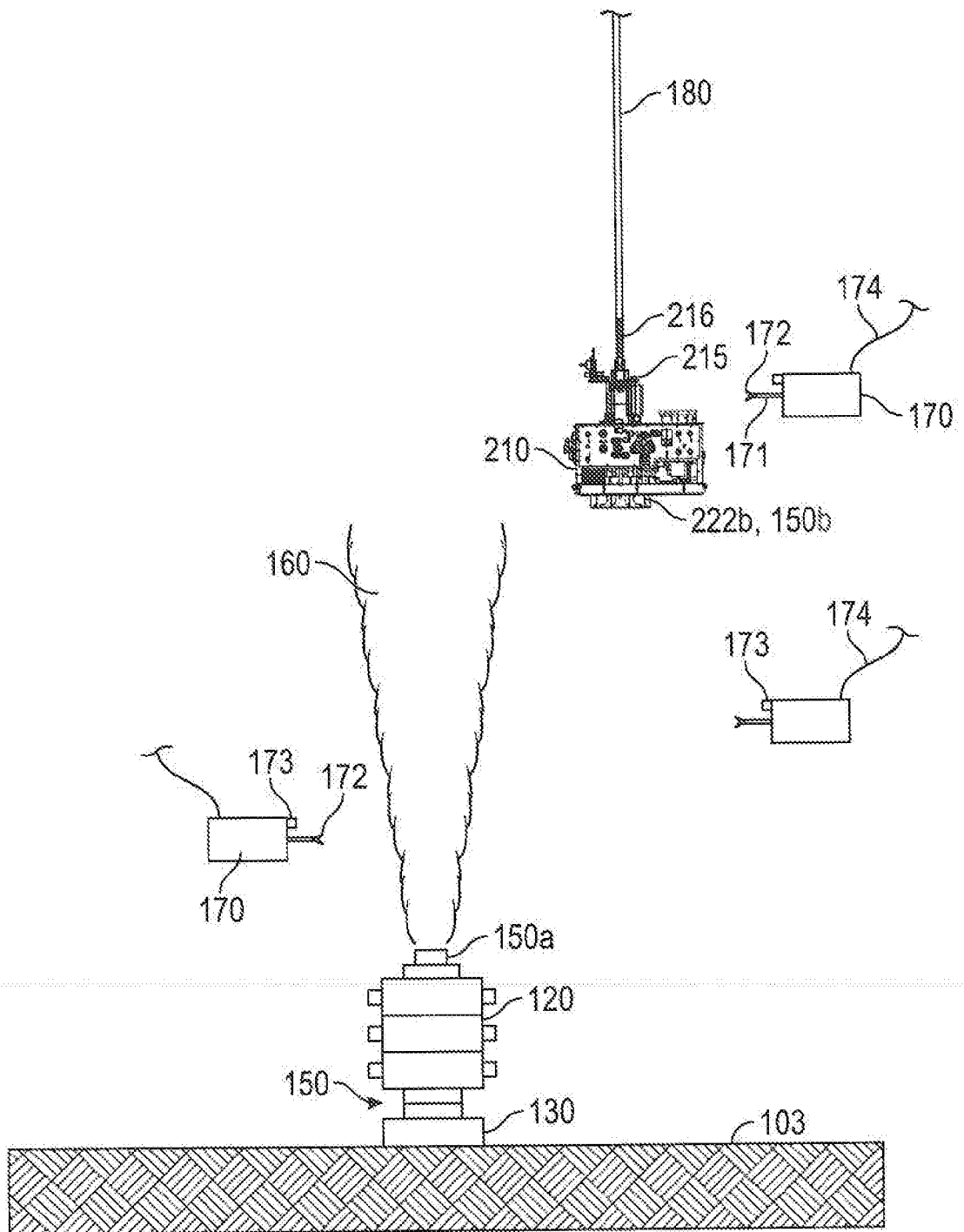


FIG. 20A

21/66

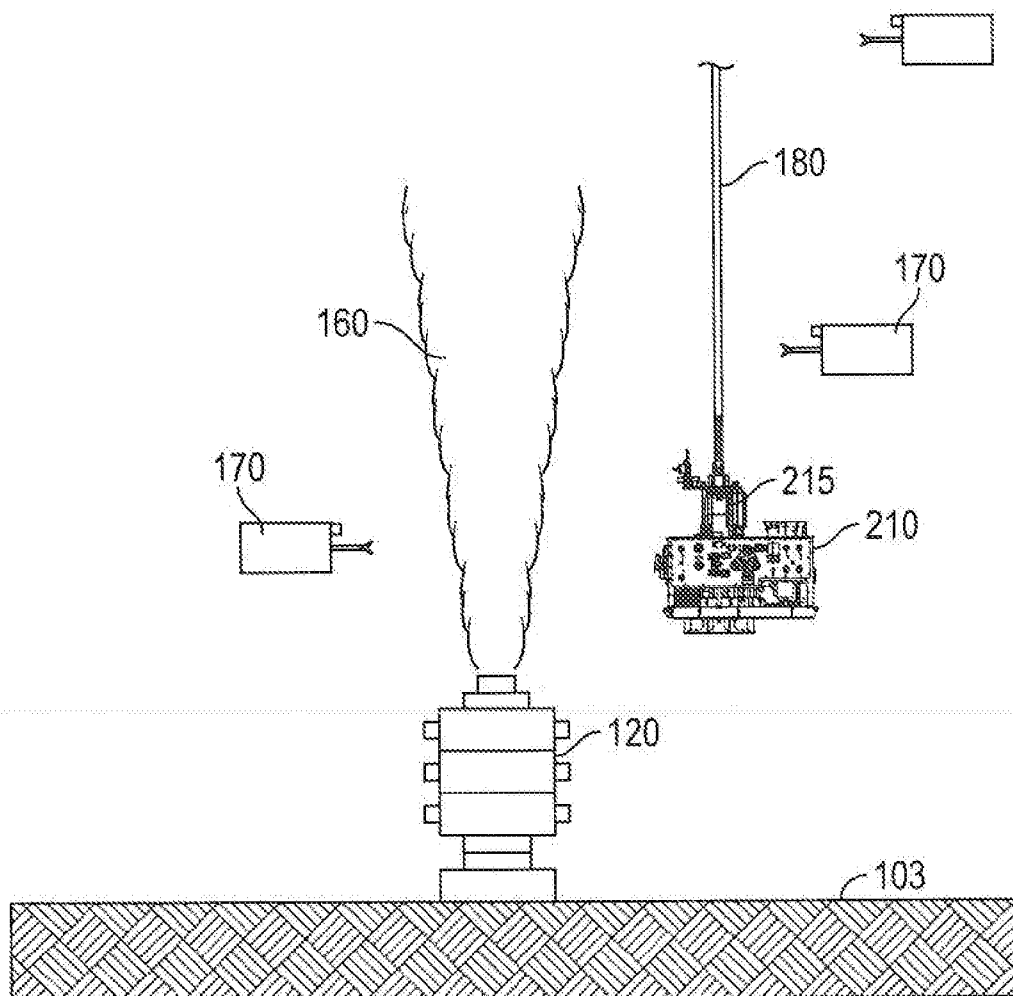


FIG. 20B

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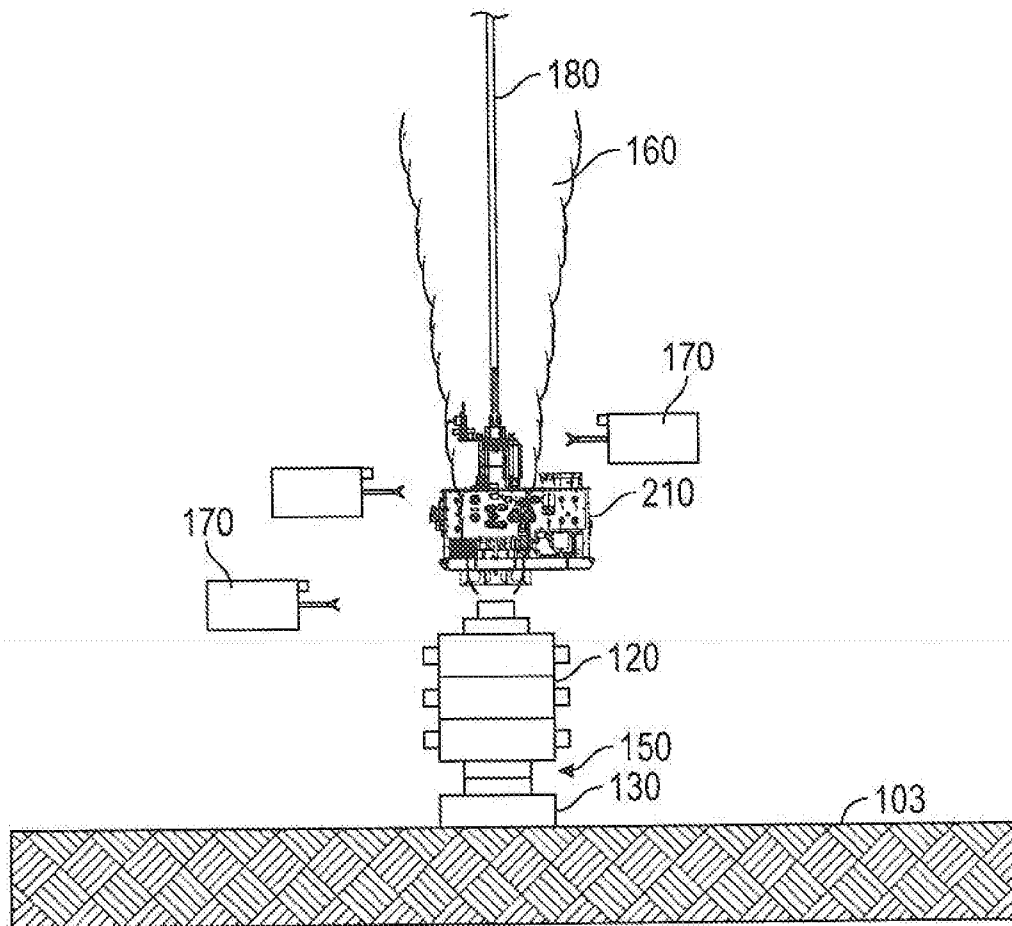


FIG. 20C

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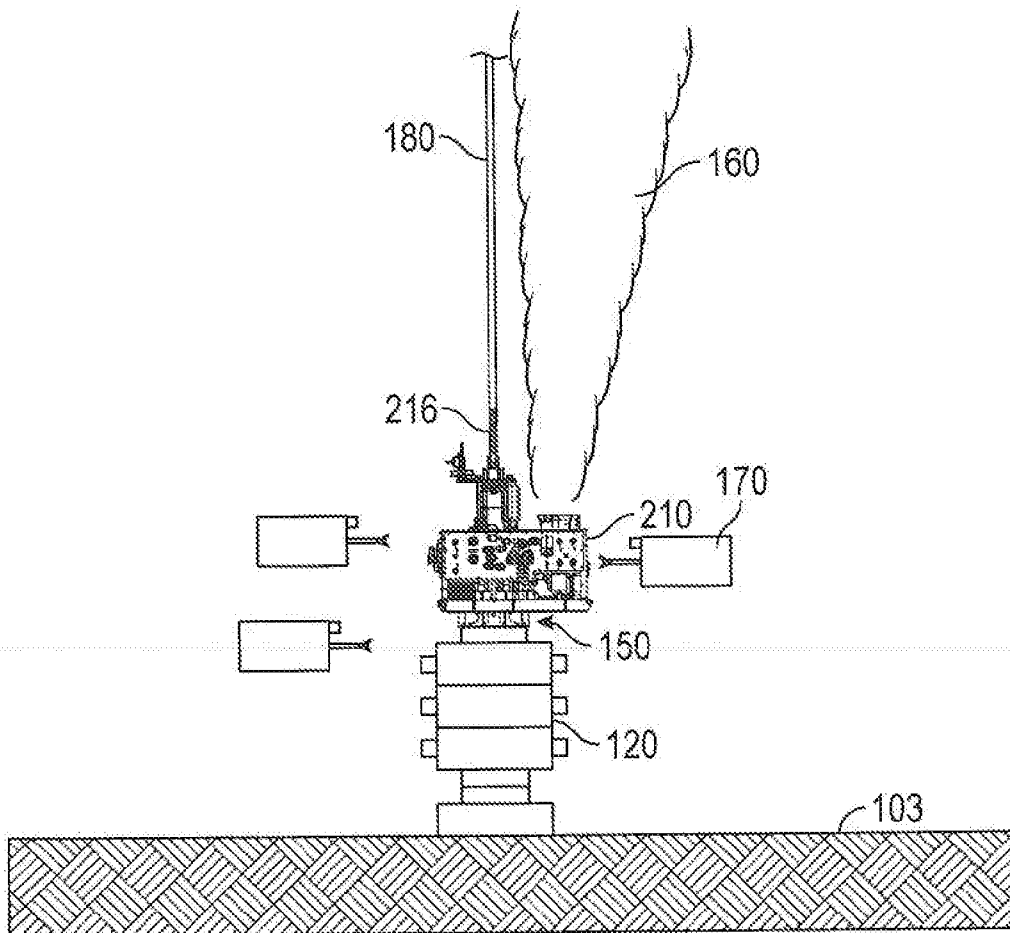


FIG. 20D

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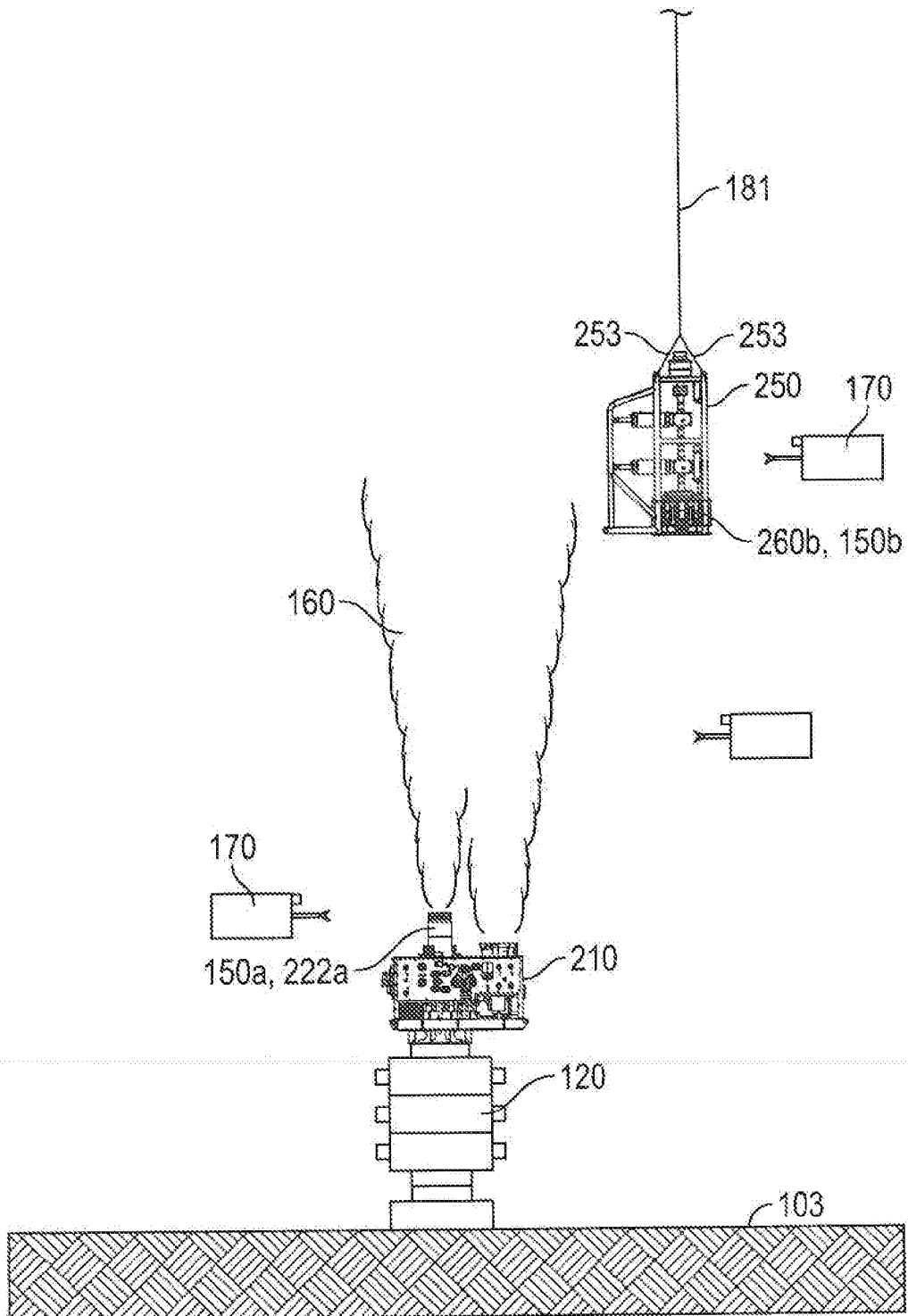


FIG. 20E

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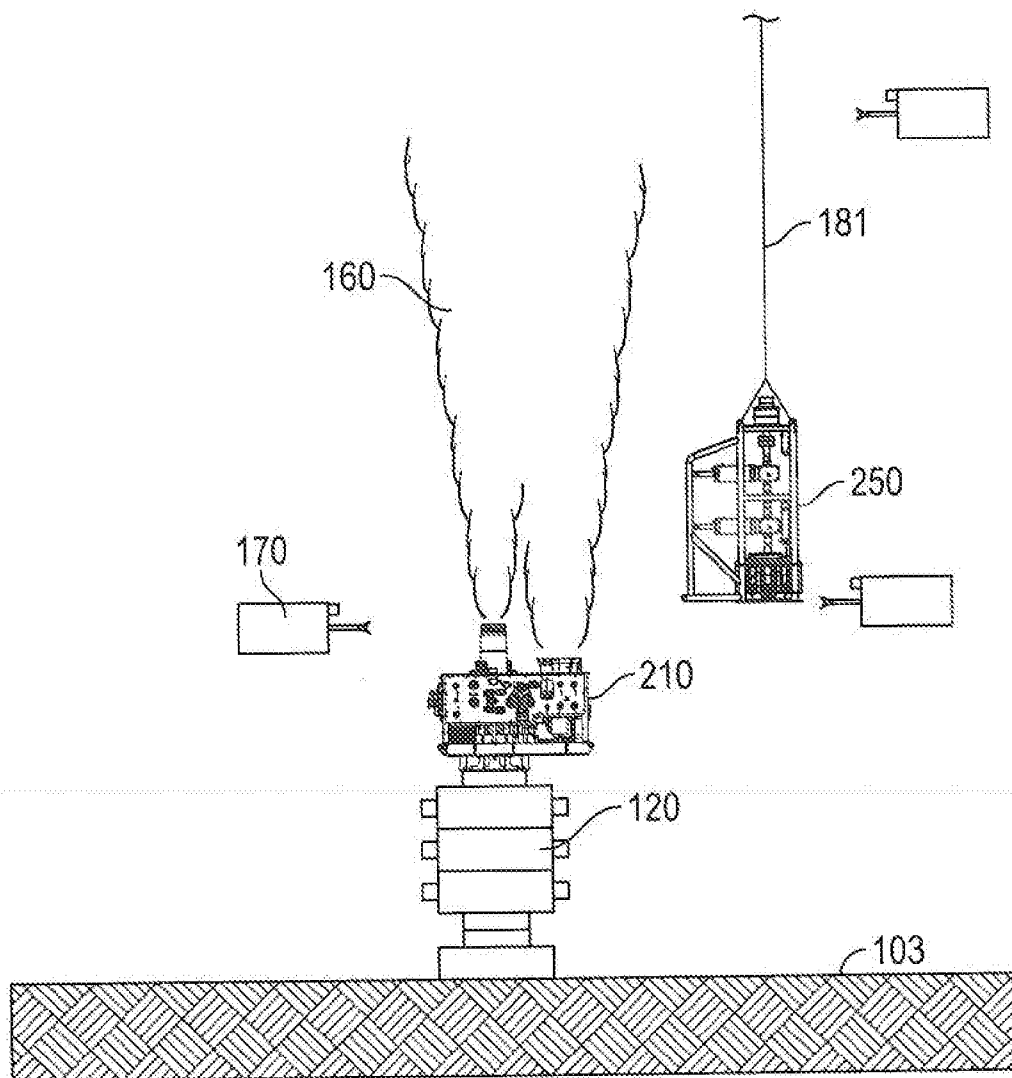


FIG. 20F

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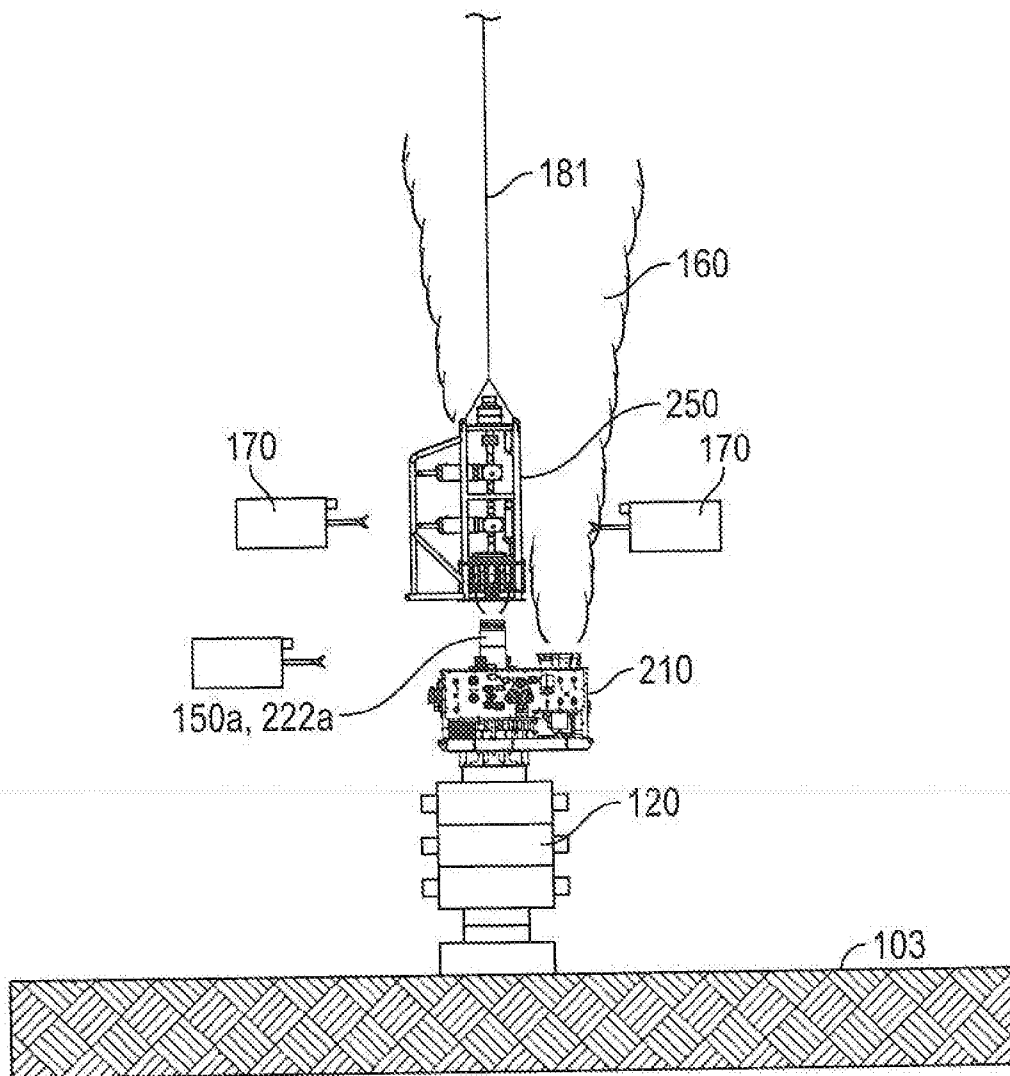


FIG. 20G

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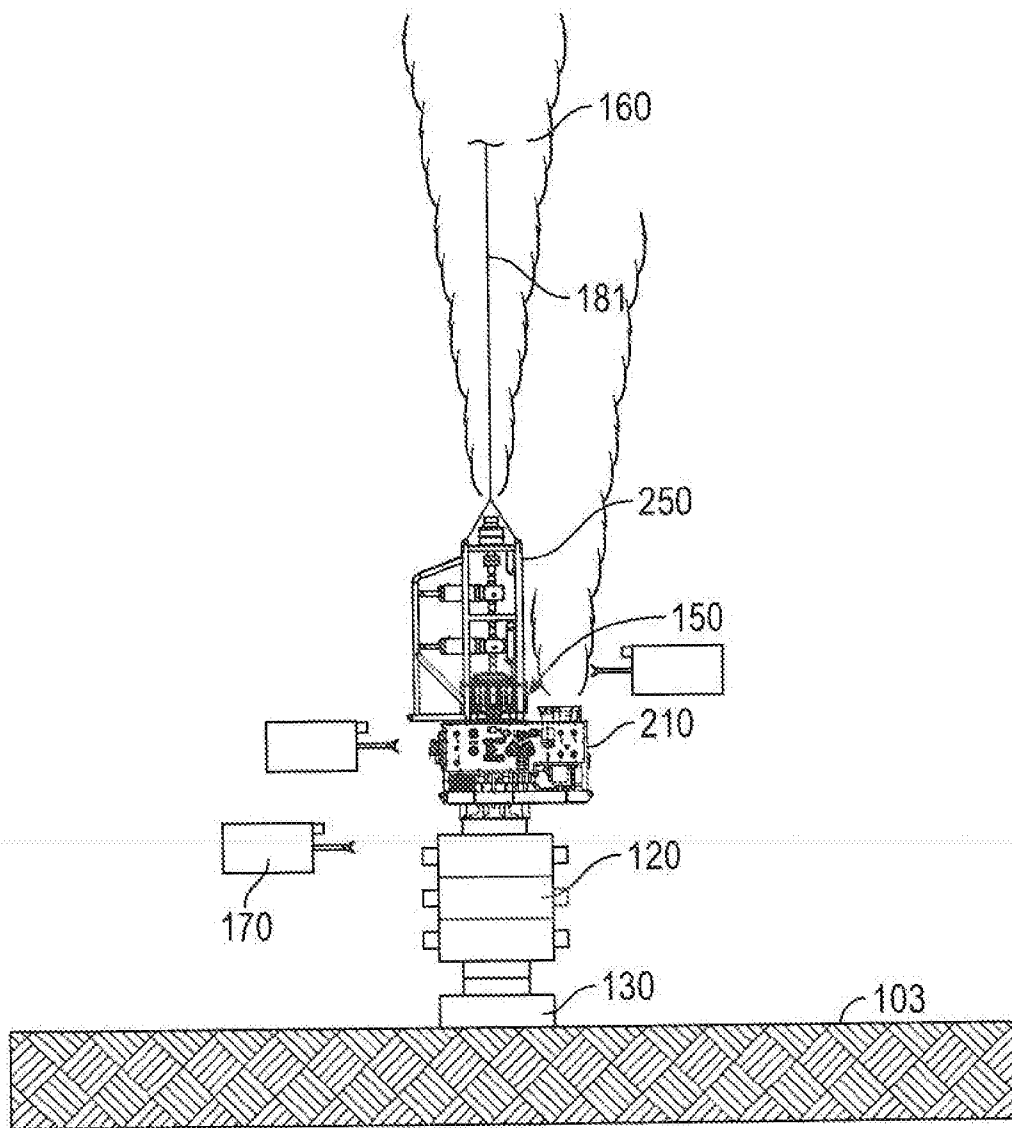


FIG. 20H

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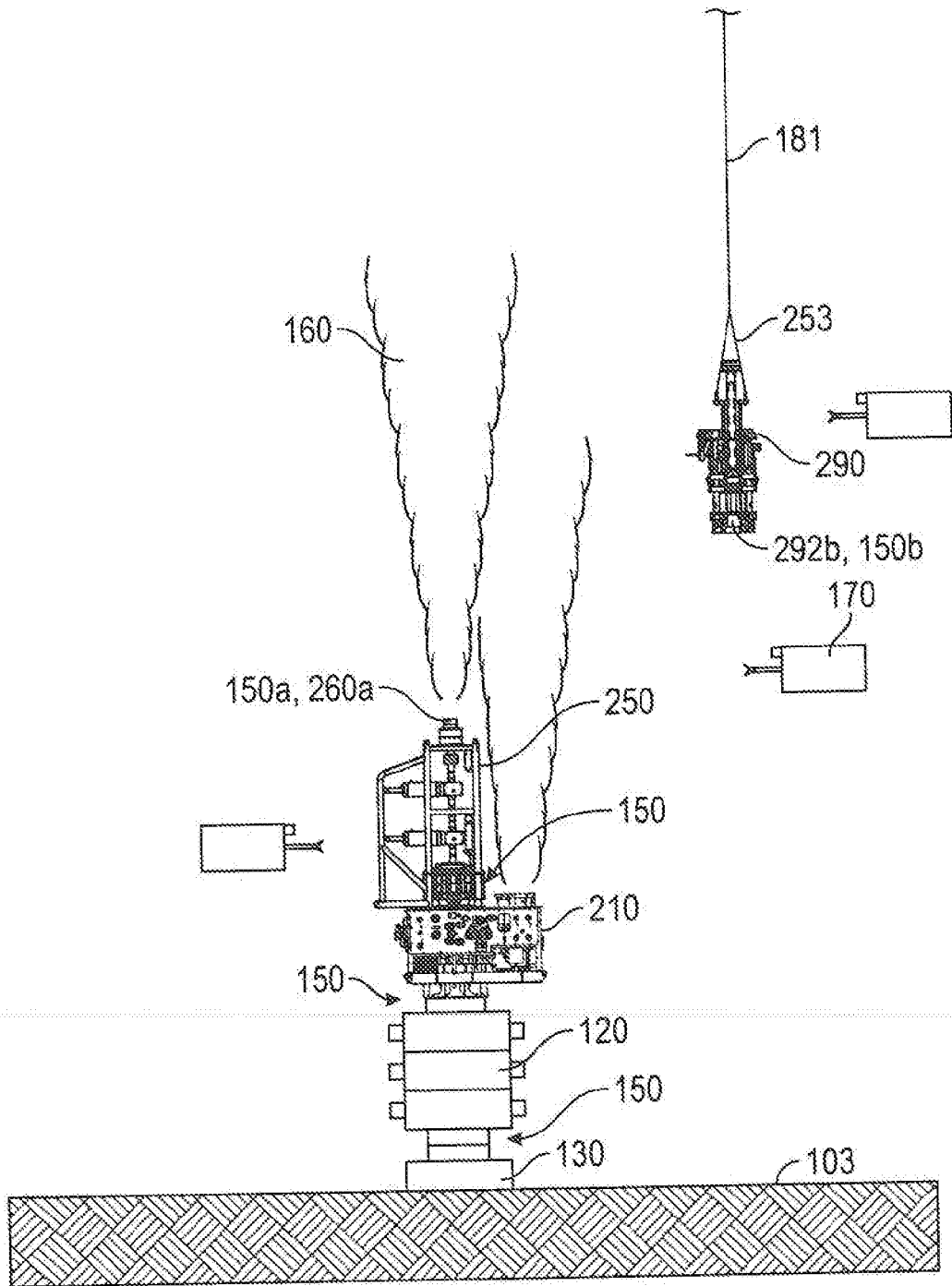


FIG. 20I

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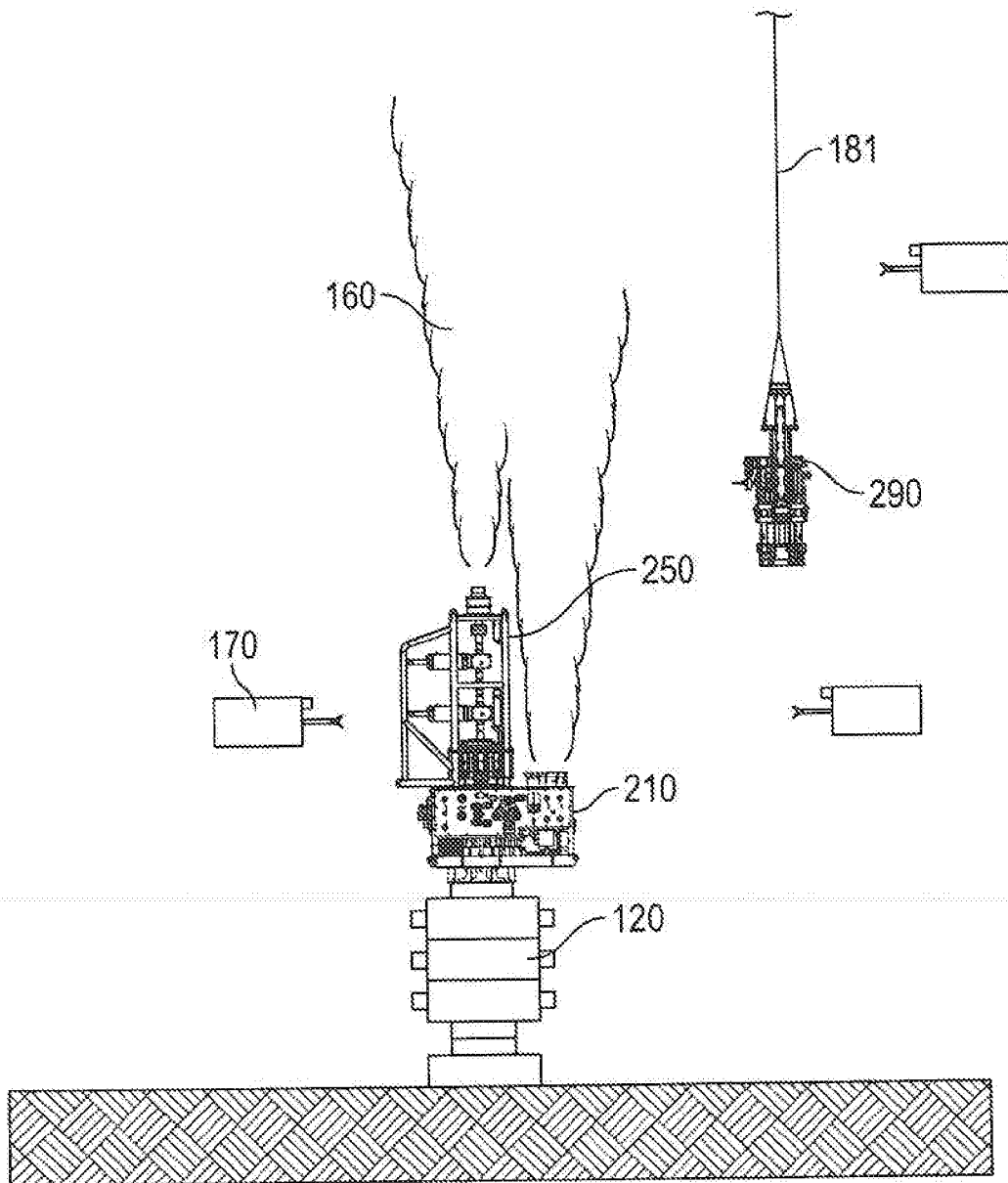


FIG. 20J

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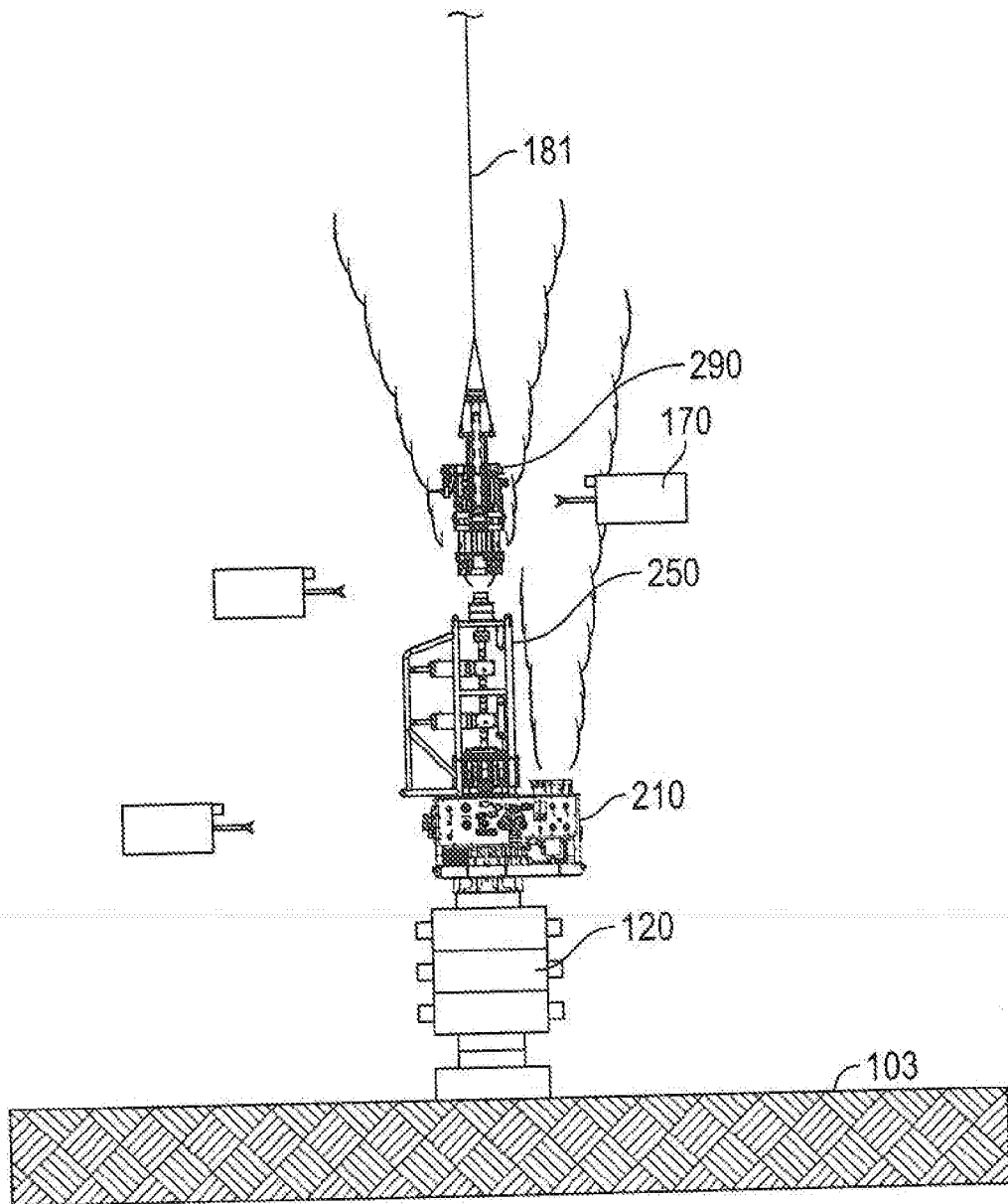


FIG. 20K

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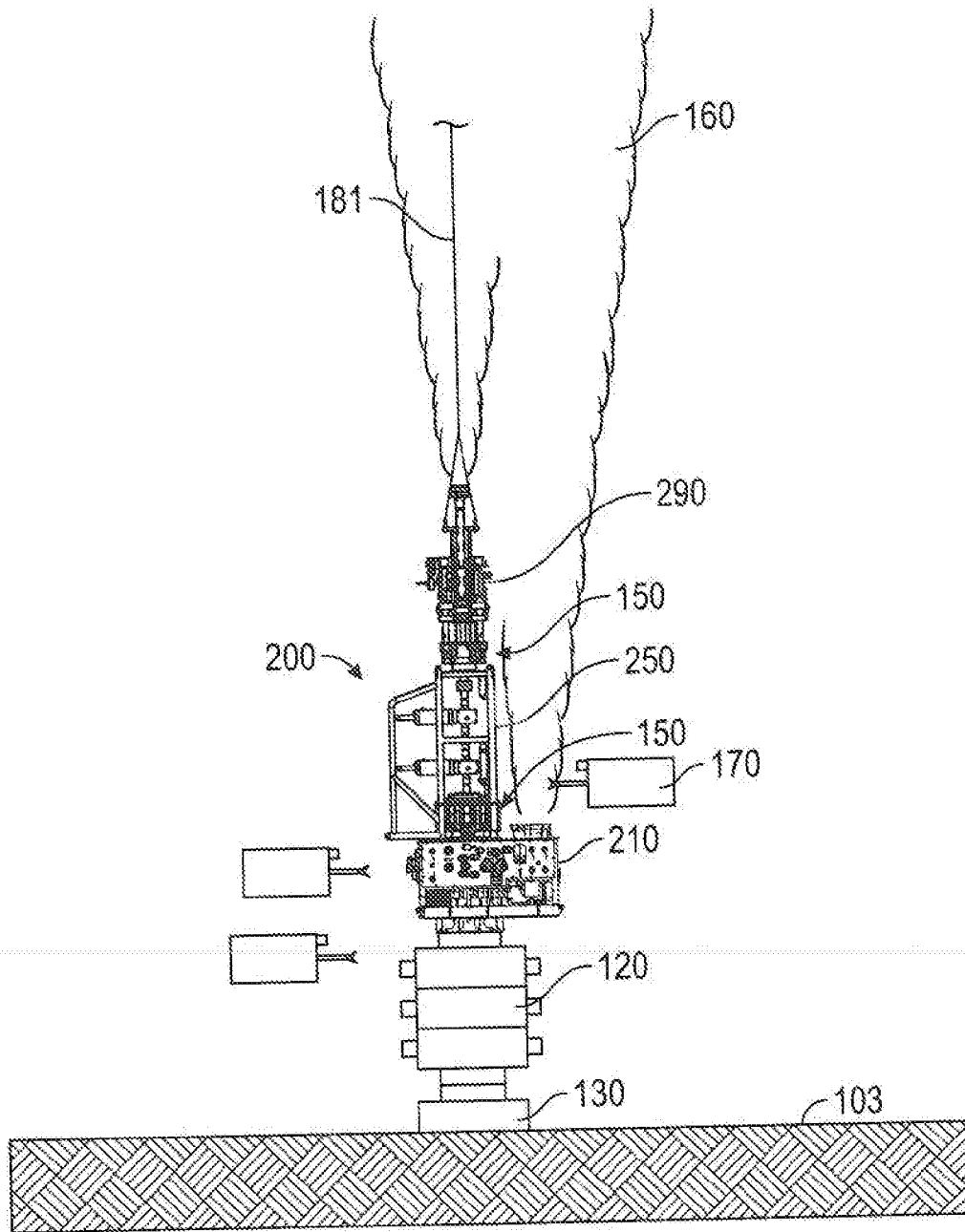


FIG. 20L

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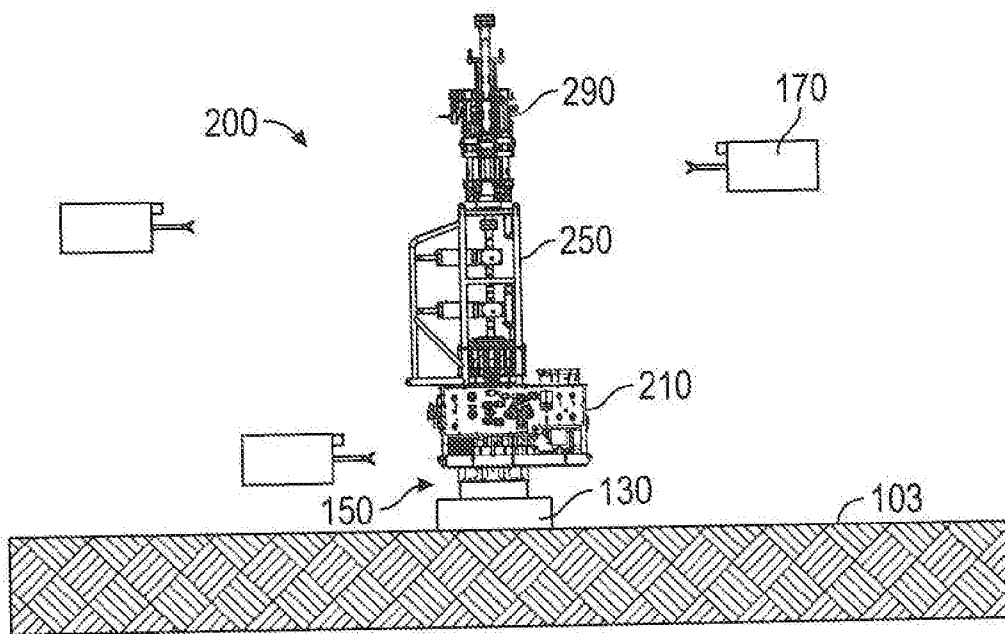


FIG. 21

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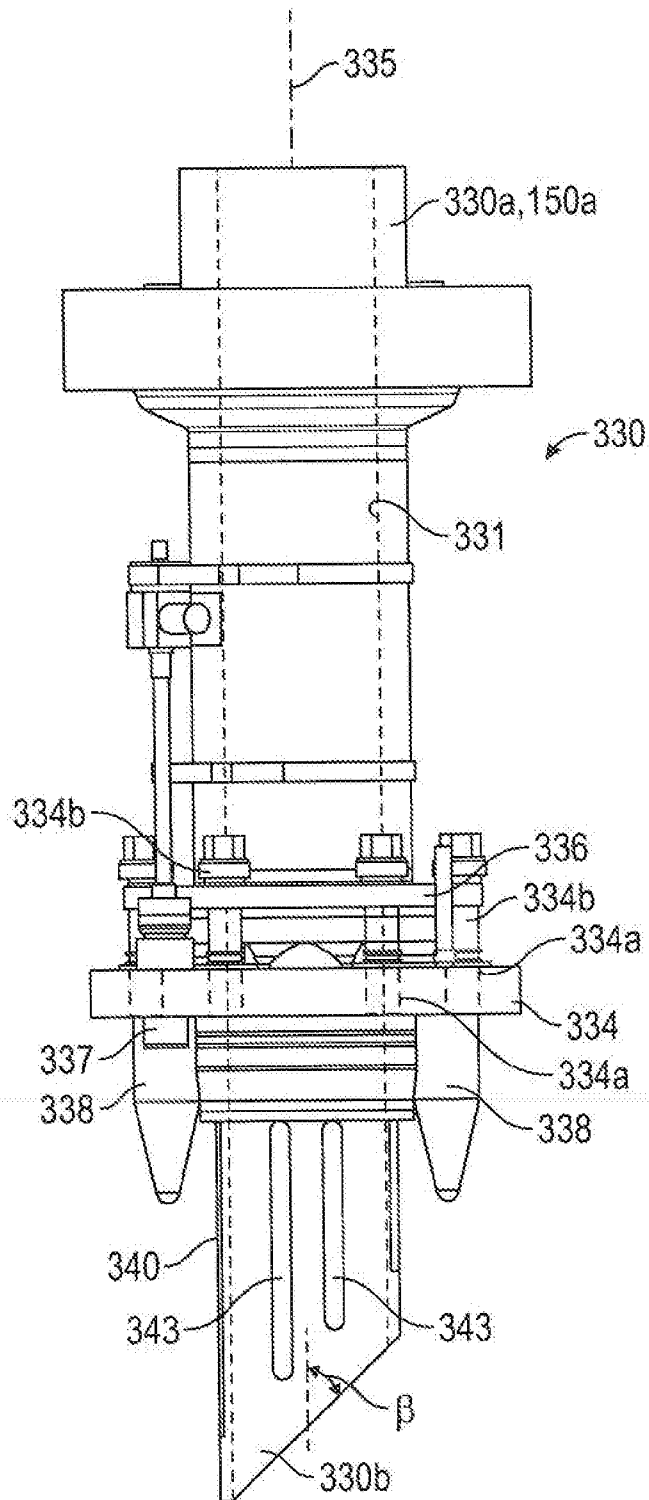


FIG. 22

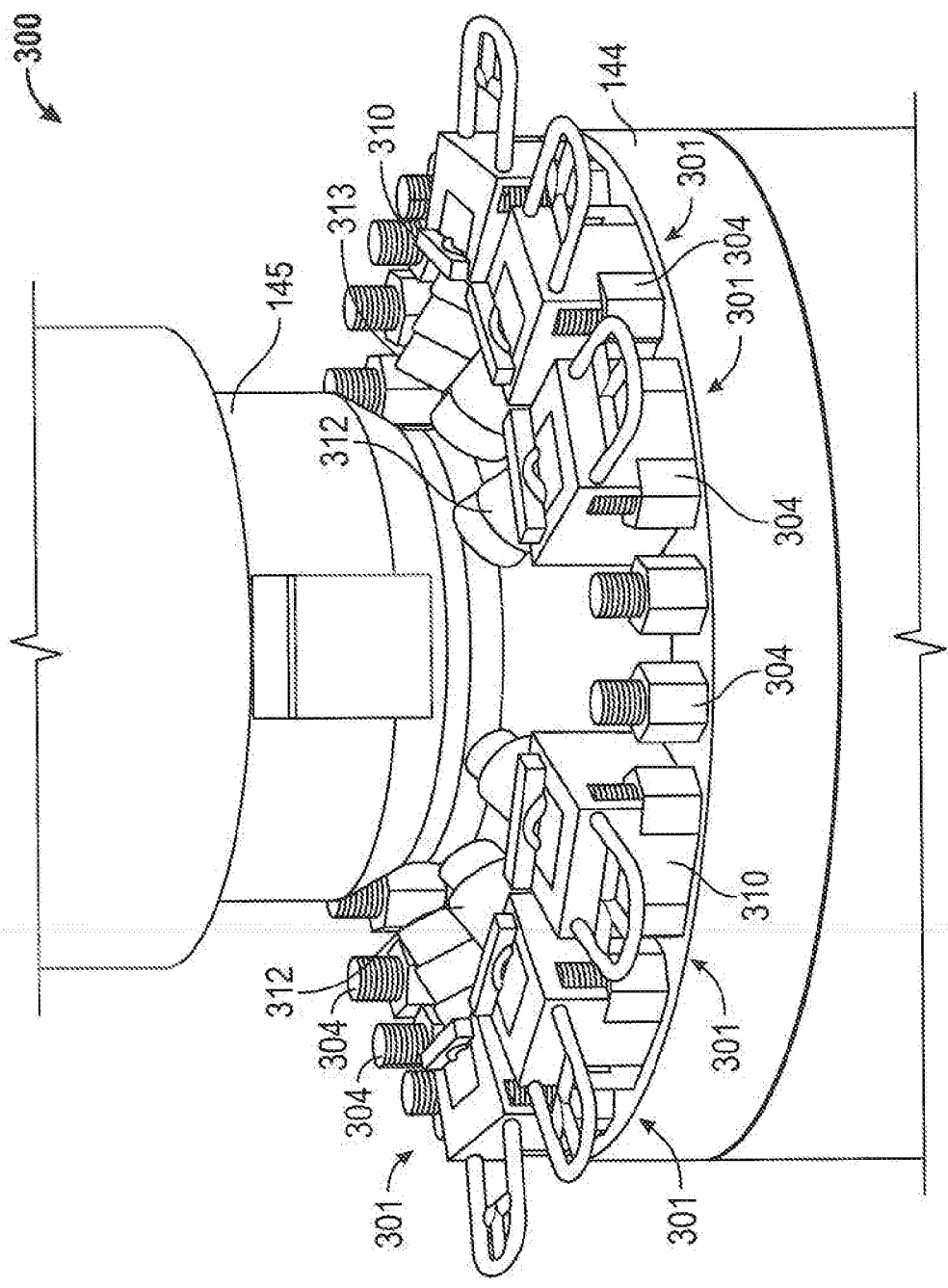


FIG. 23

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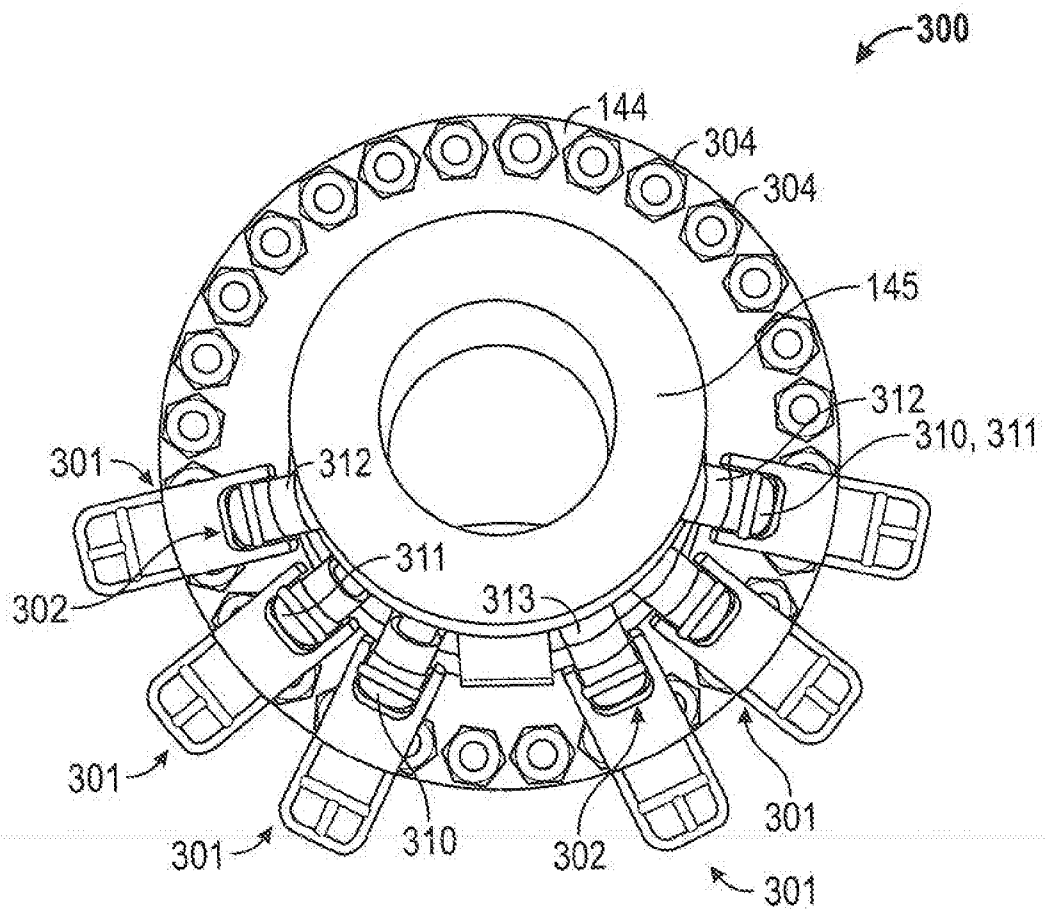
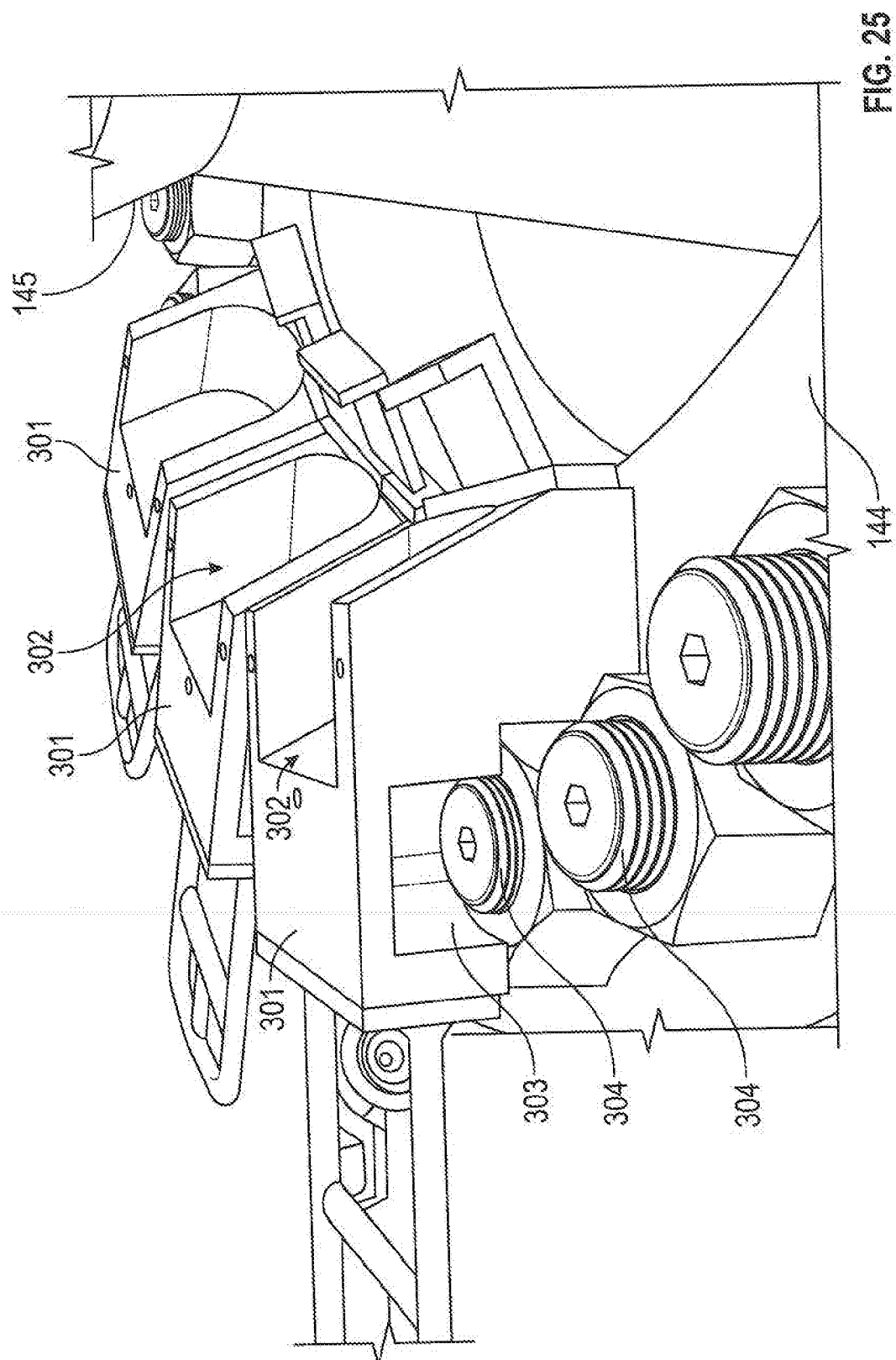


FIG. 24

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4. 25

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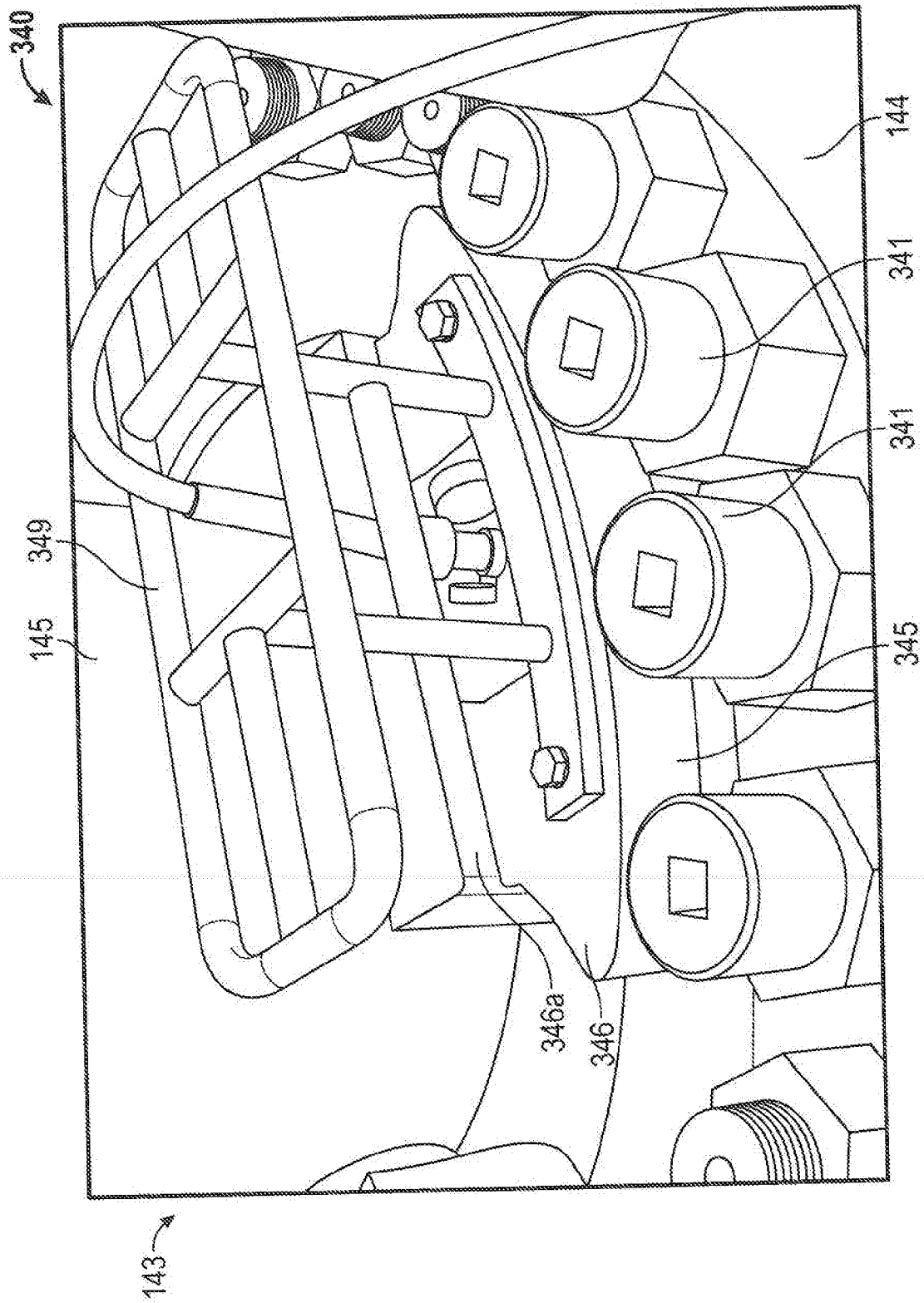


FIG. 26

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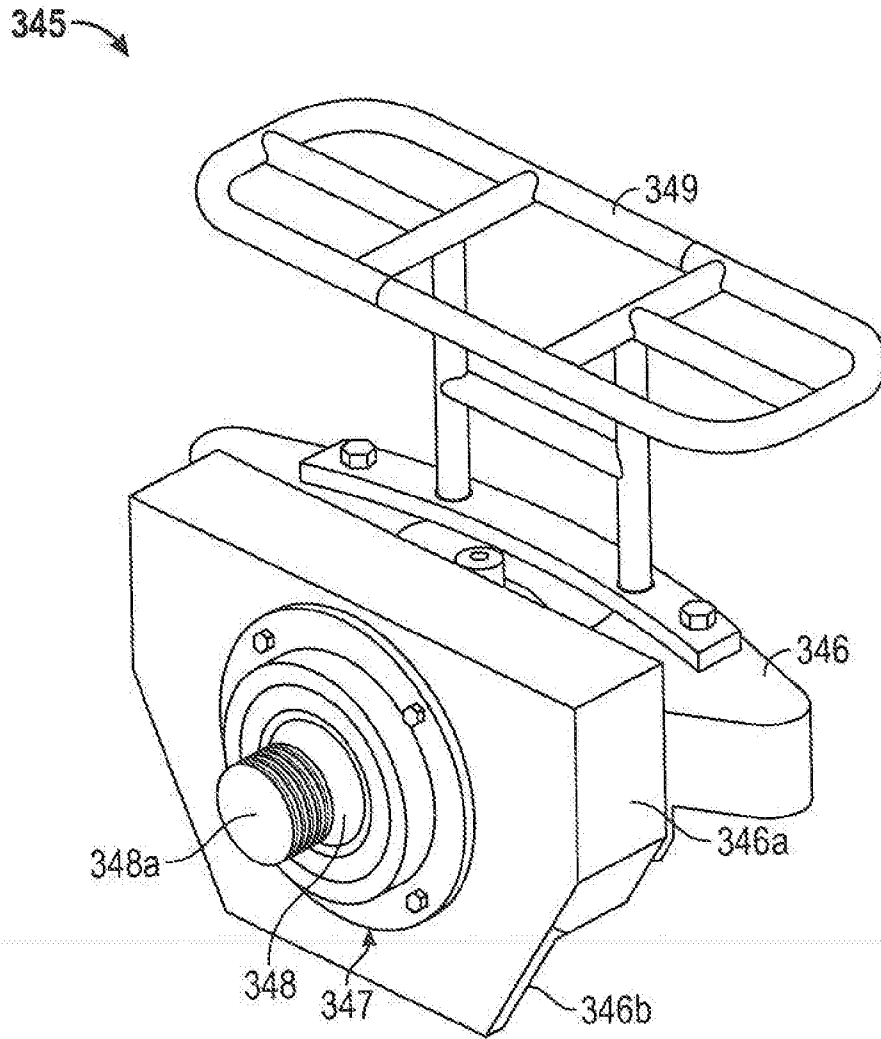


FIG. 27

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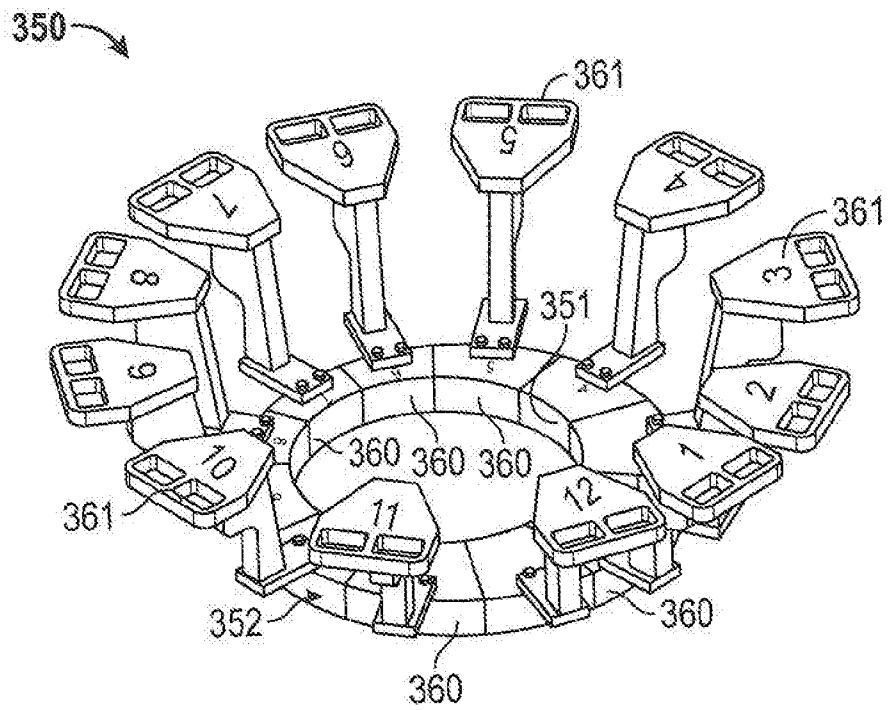


FIG. 28

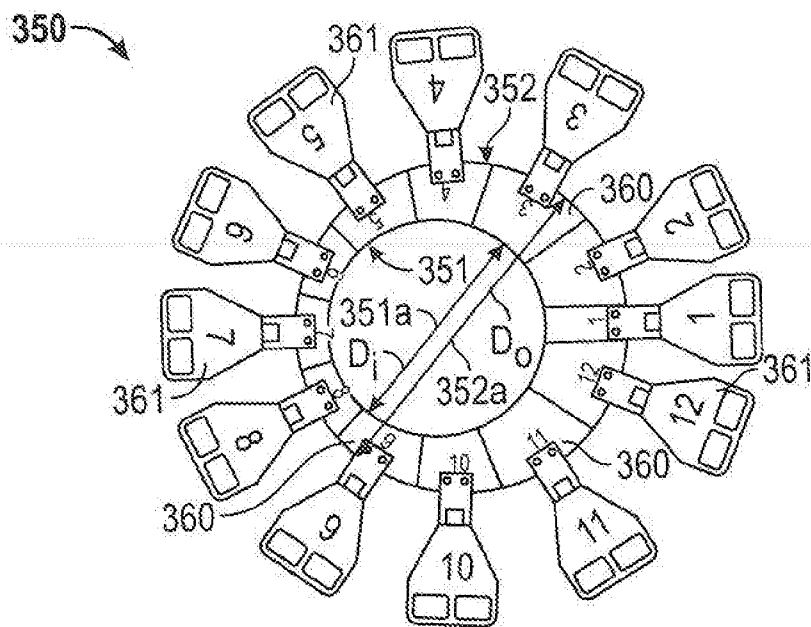


FIG. 29

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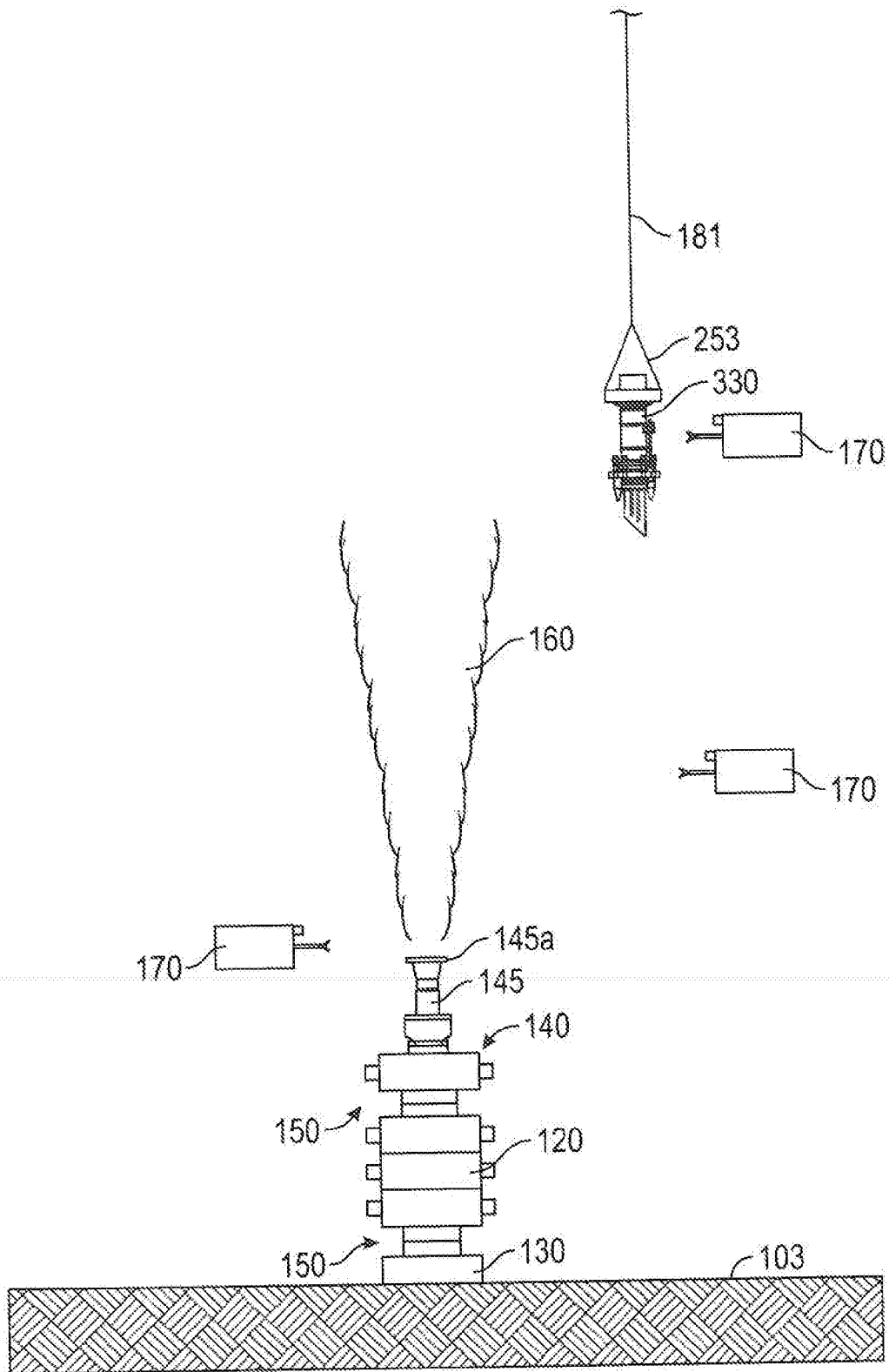


FIG. 30A

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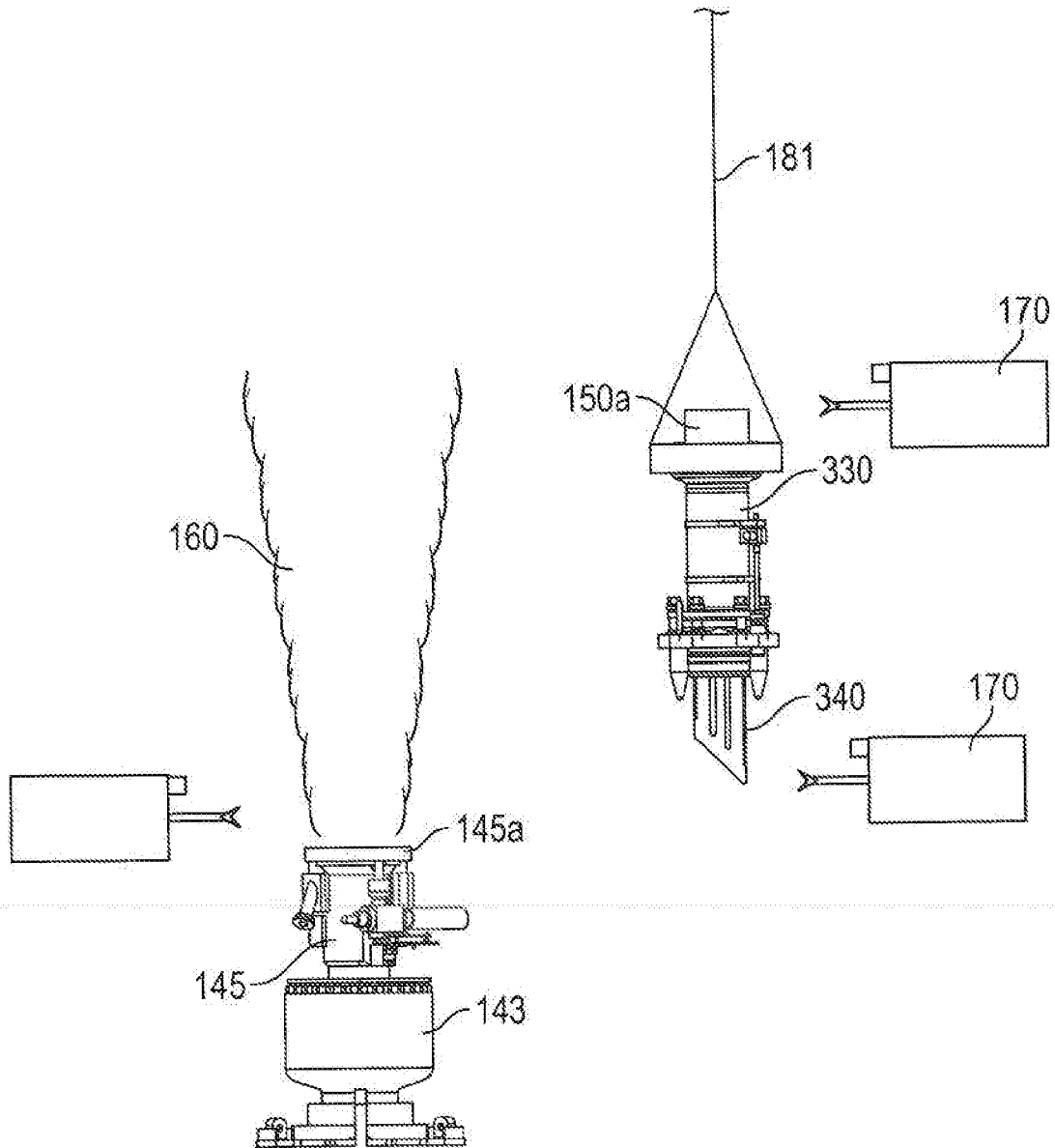


FIG. 30B

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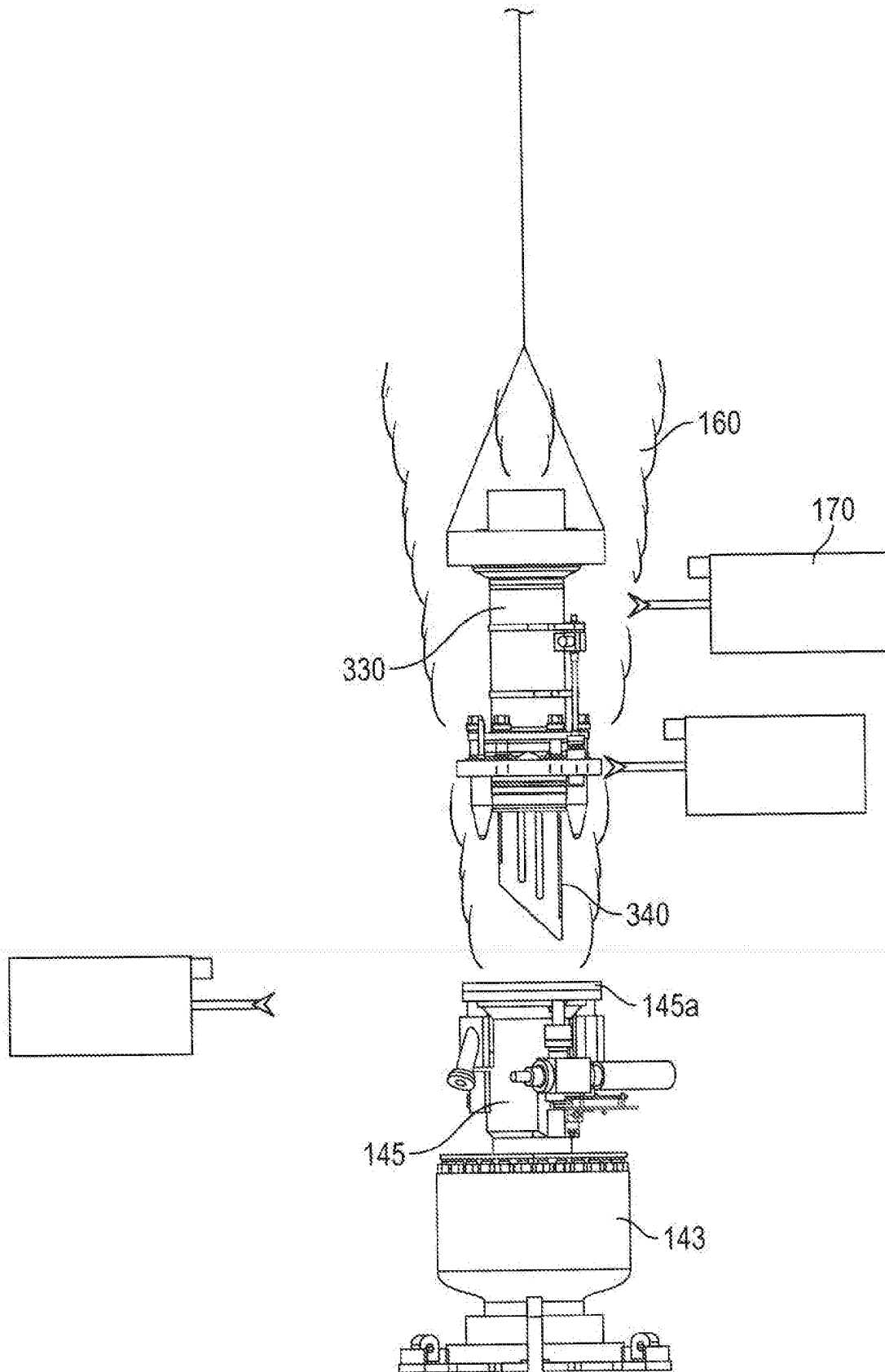


FIG. 30C

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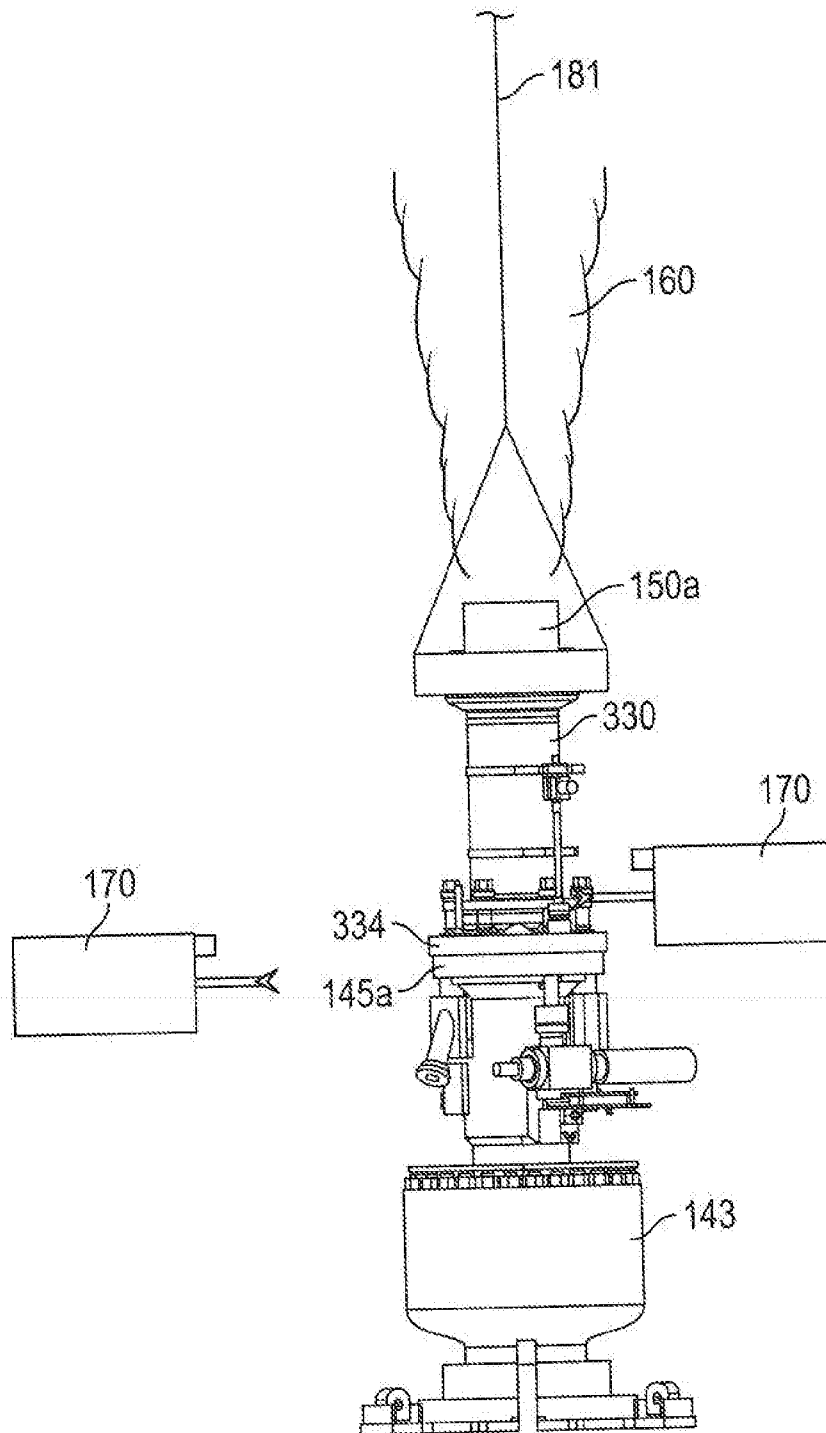


FIG. 30D

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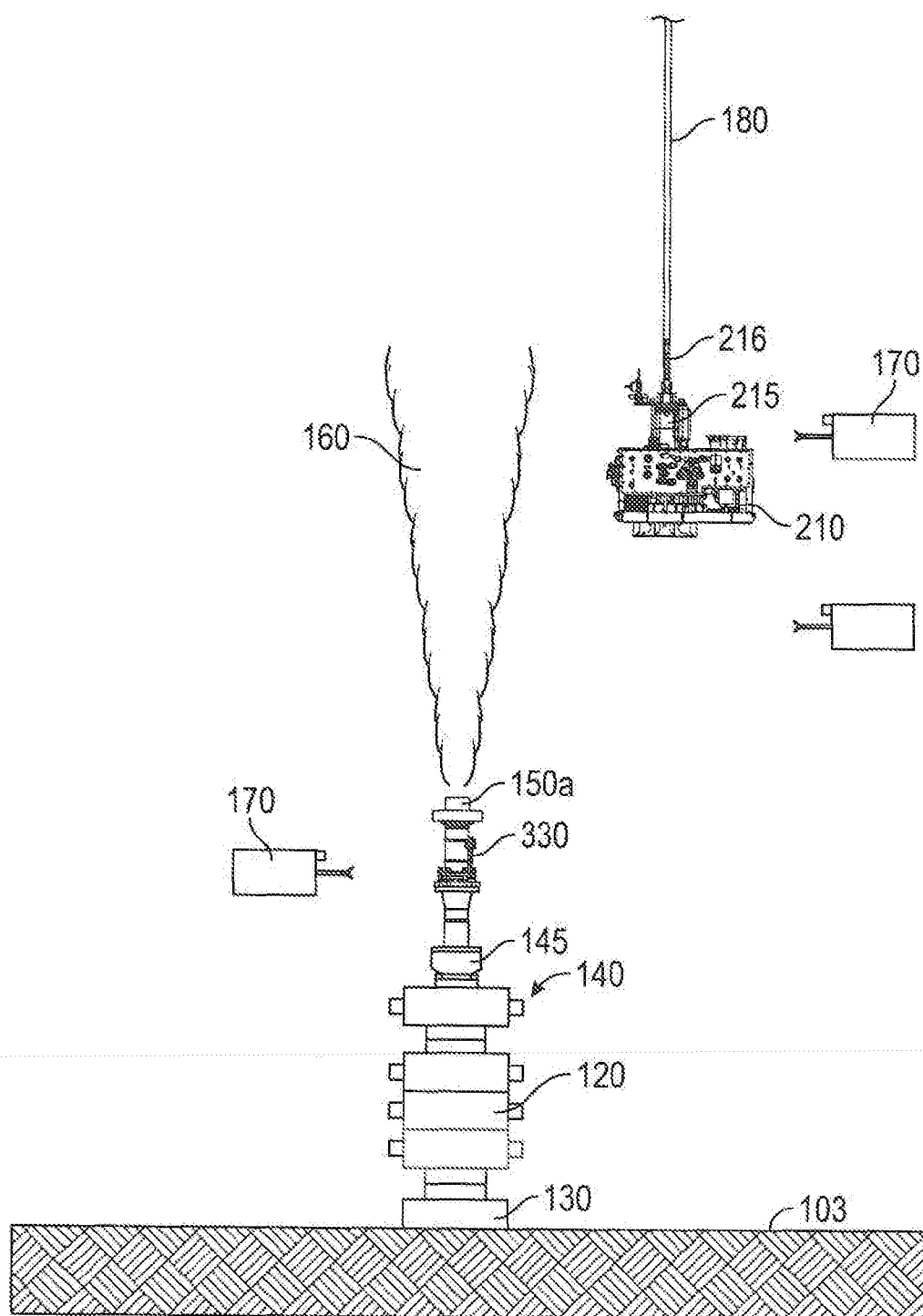


FIG. 30E

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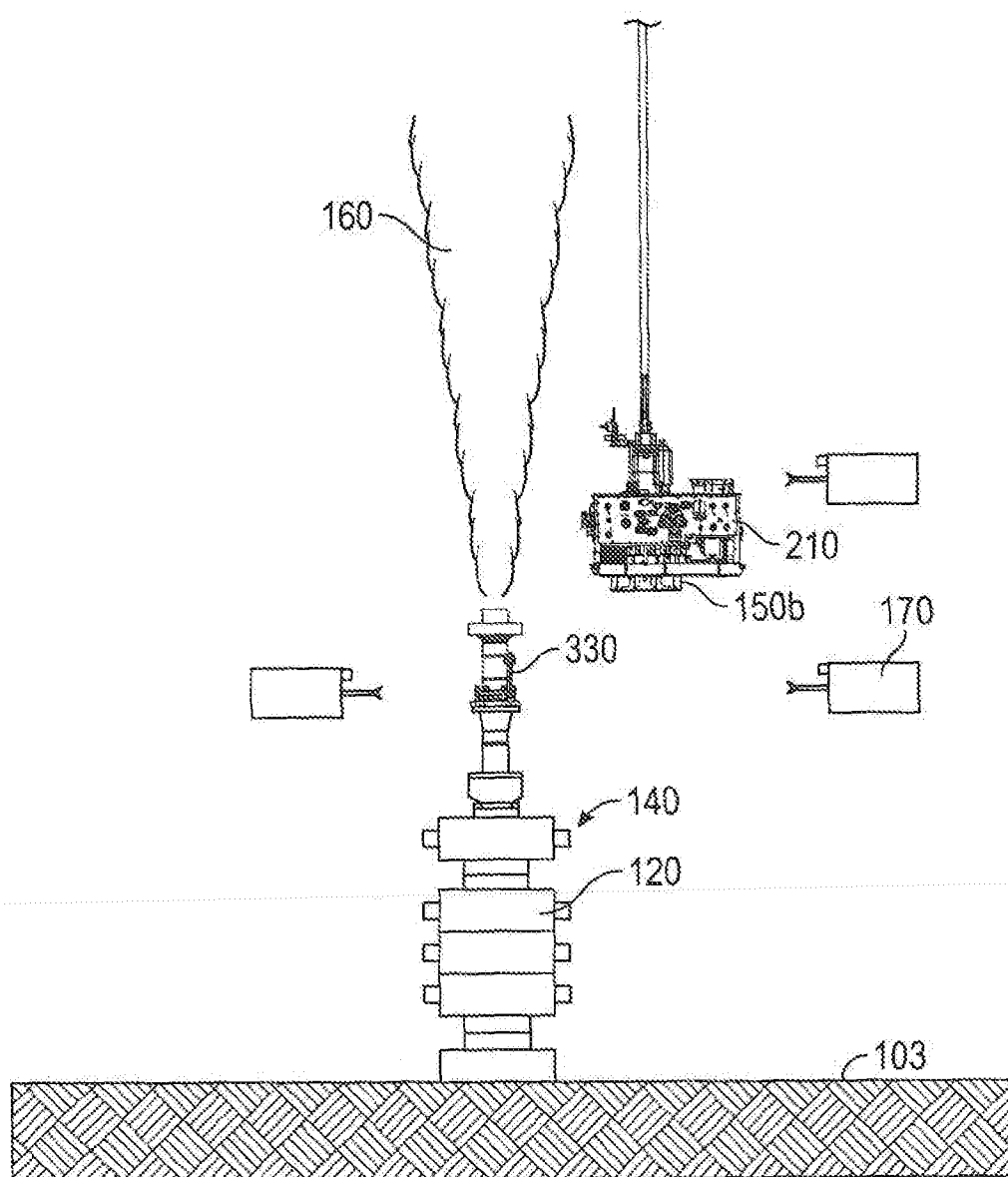


FIG. 30F

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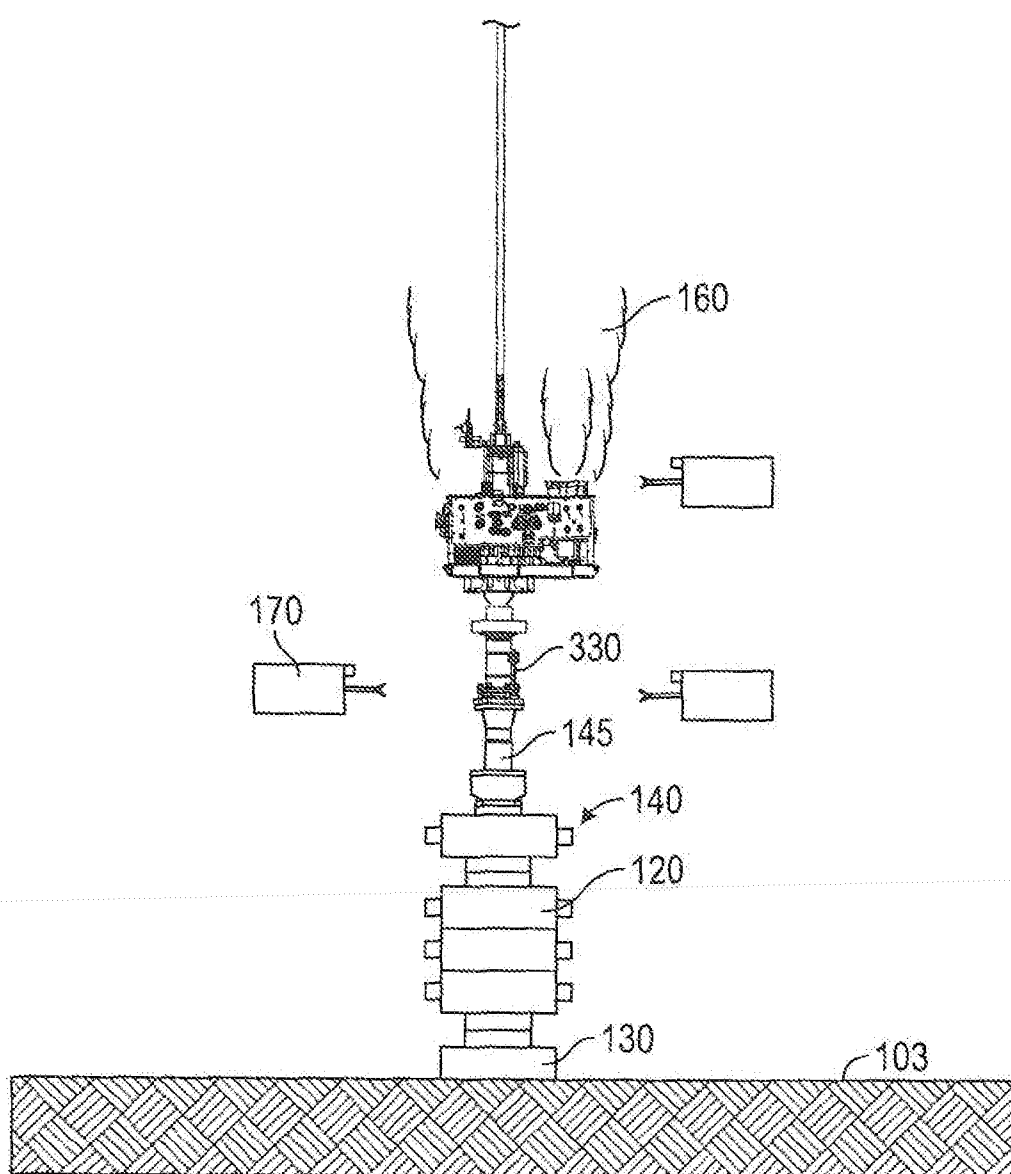


FIG. 30G

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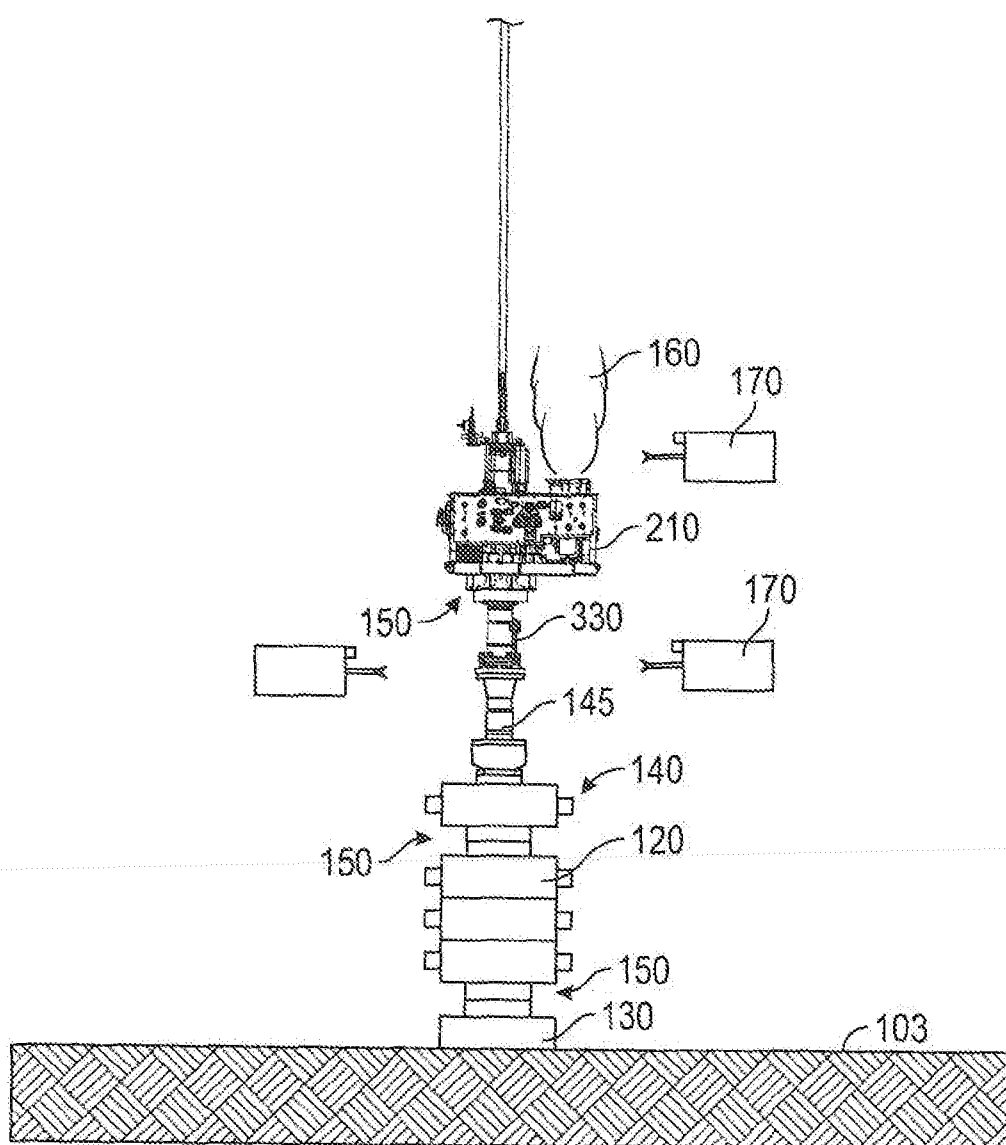


FIG. 30H

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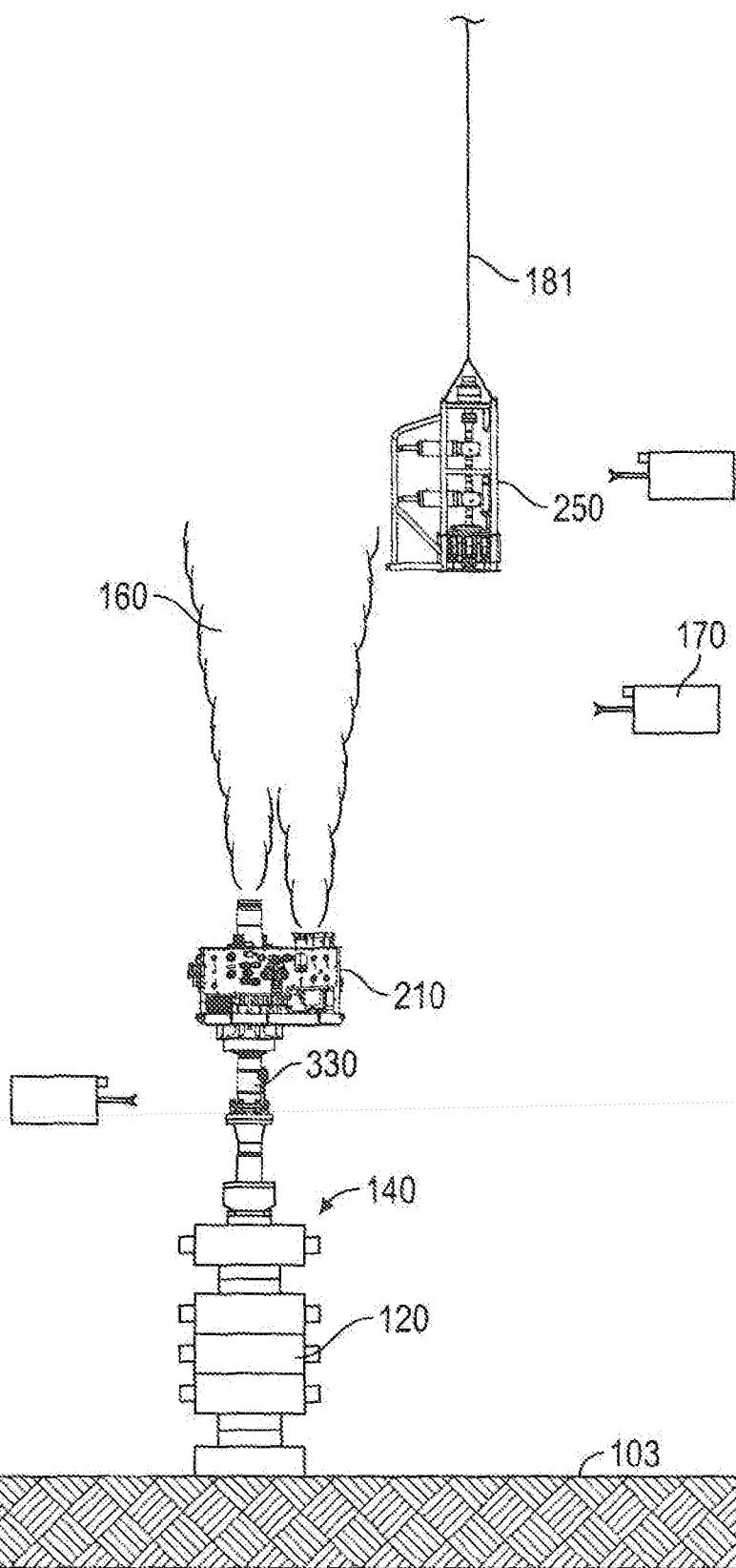


FIG. 30I

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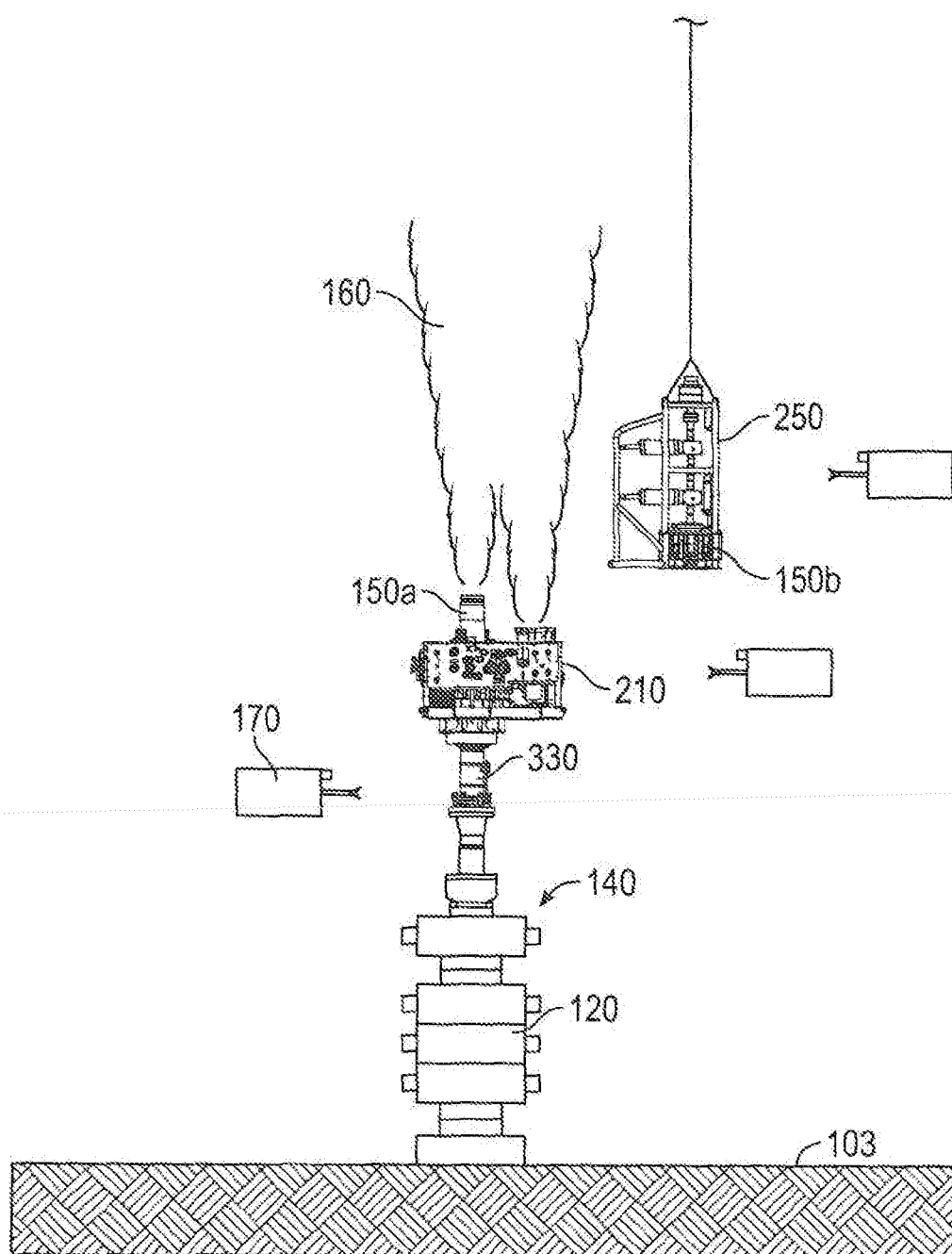


FIG. 30J

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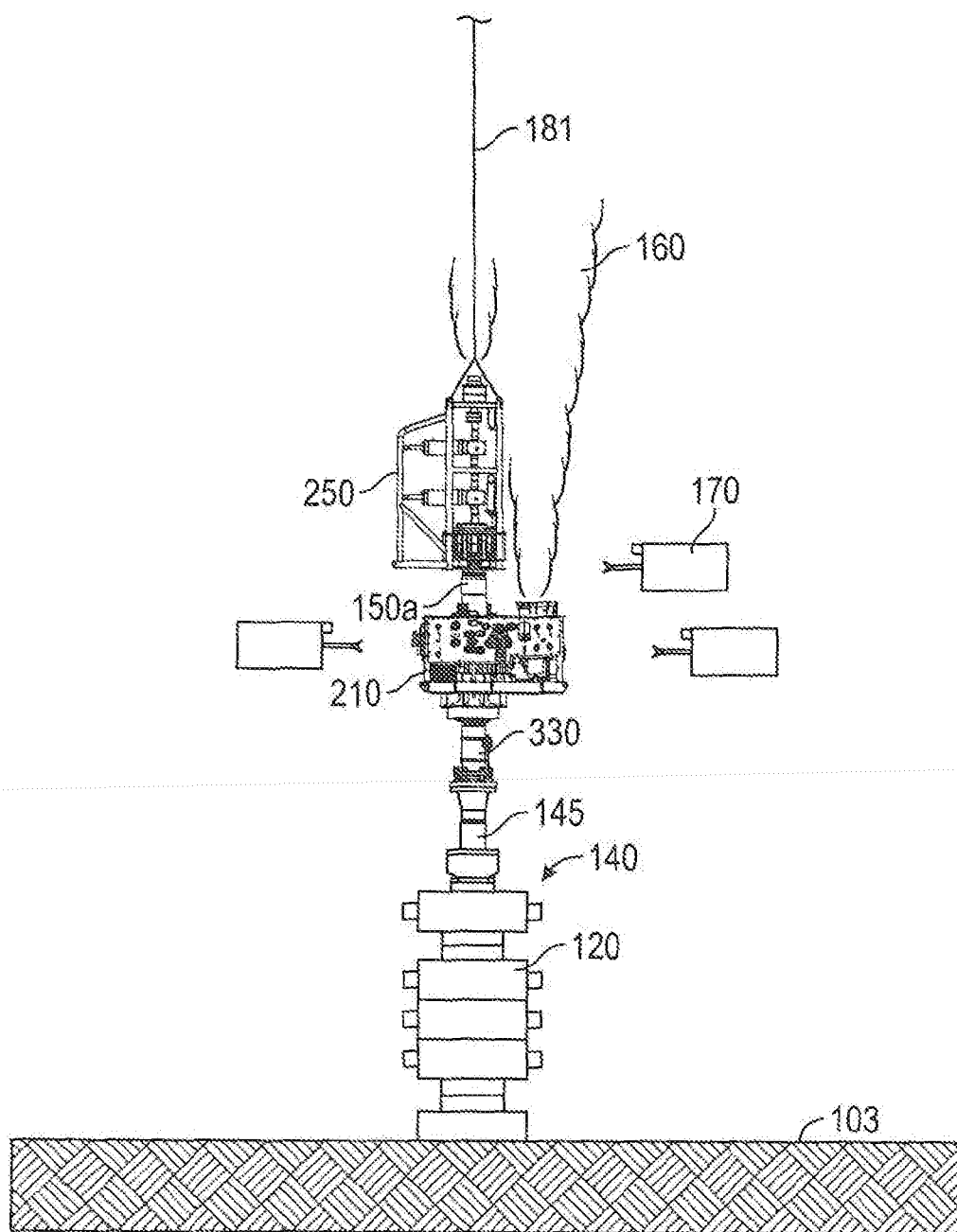


FIG. 30K

5166

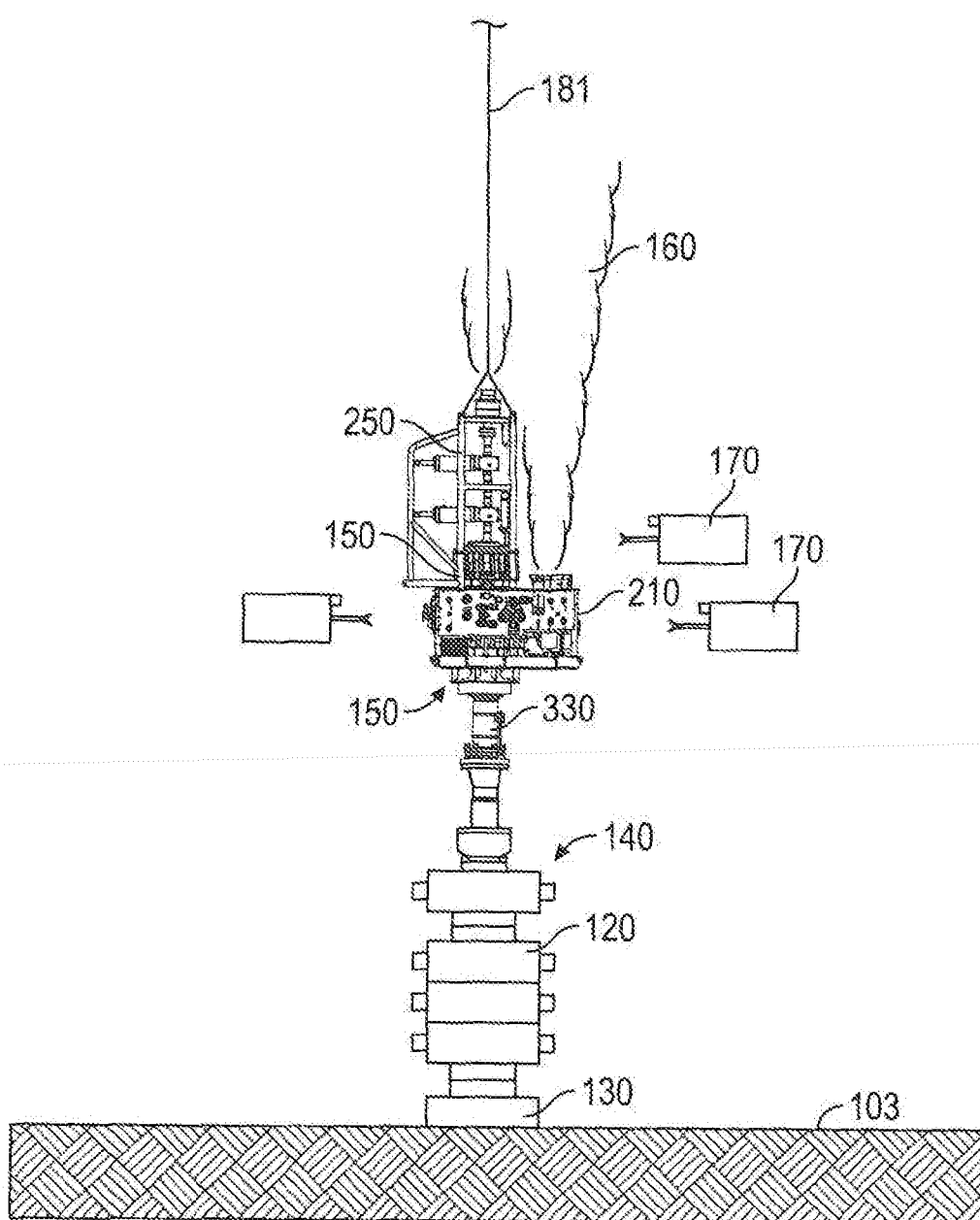


FIG. 30L

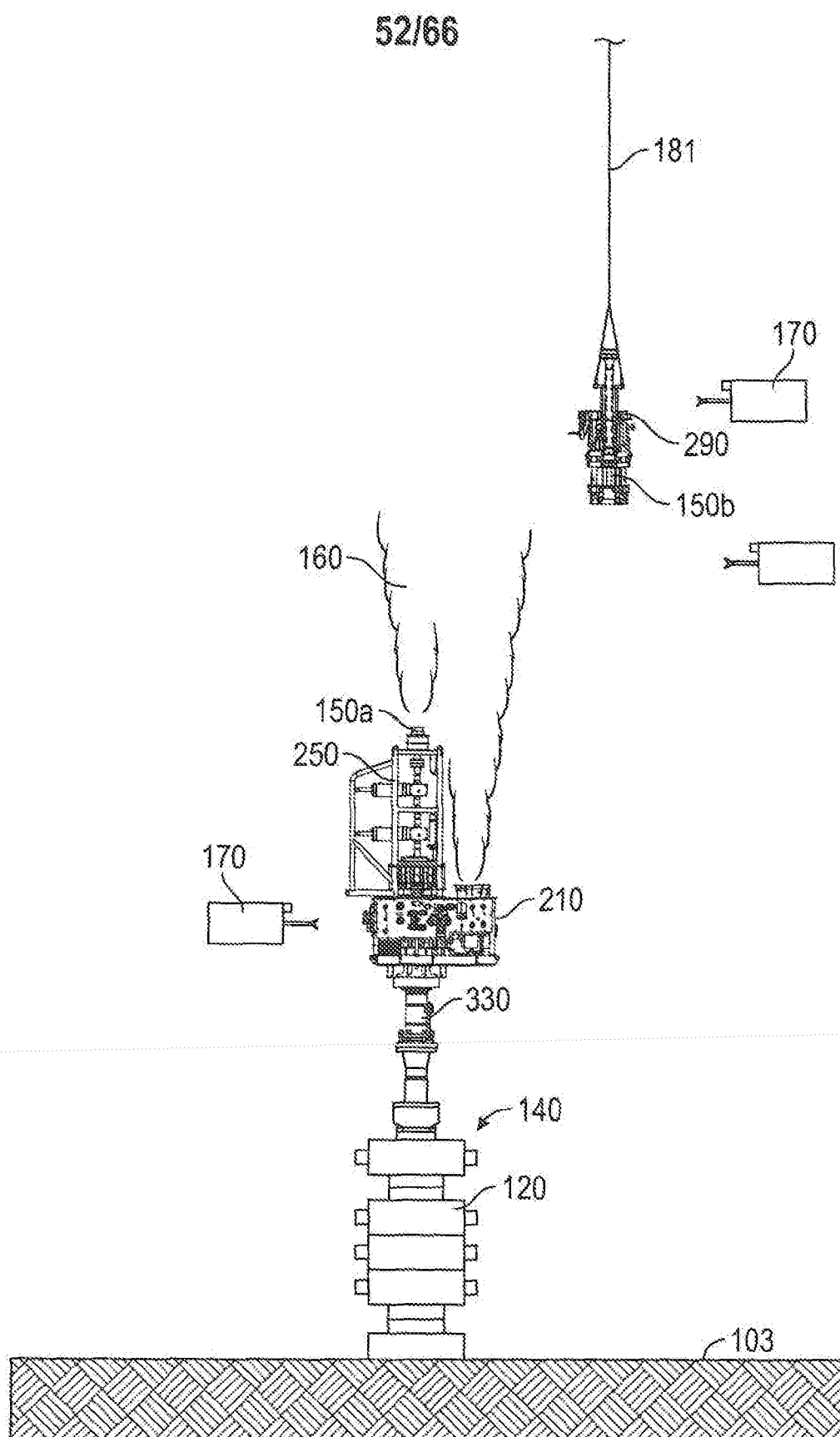


FIG. 30M

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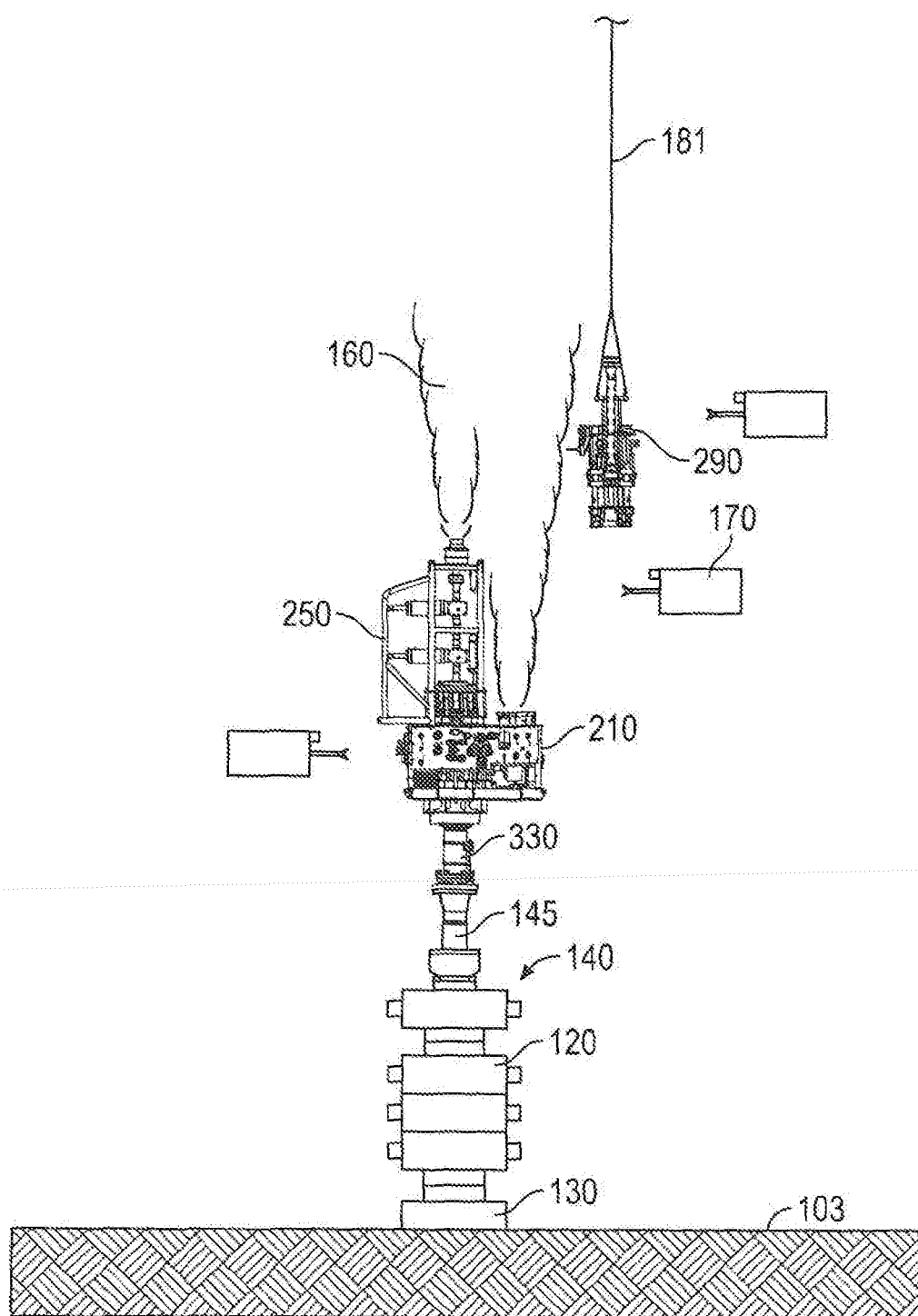


FIG. 30N

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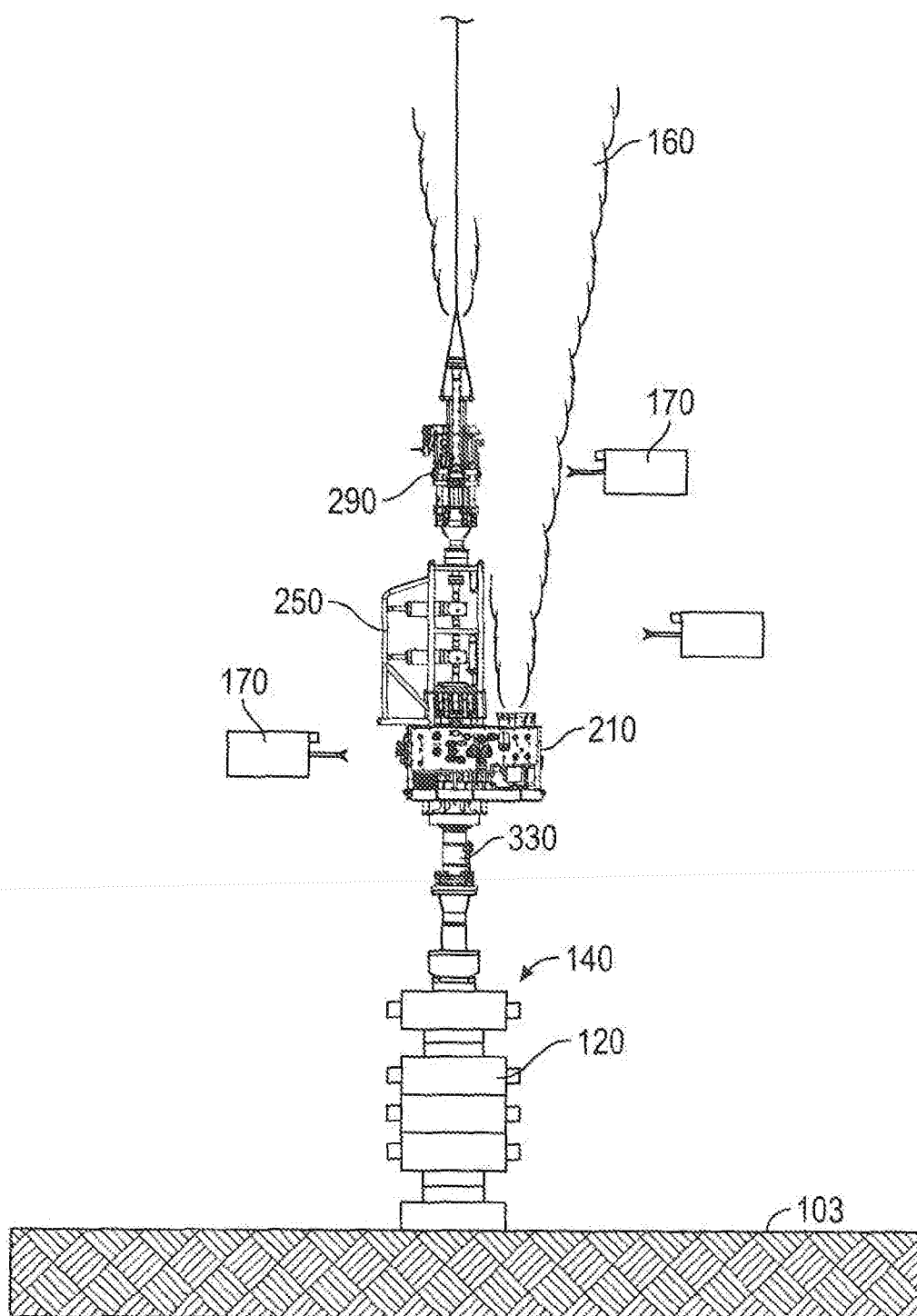


FIG. 300

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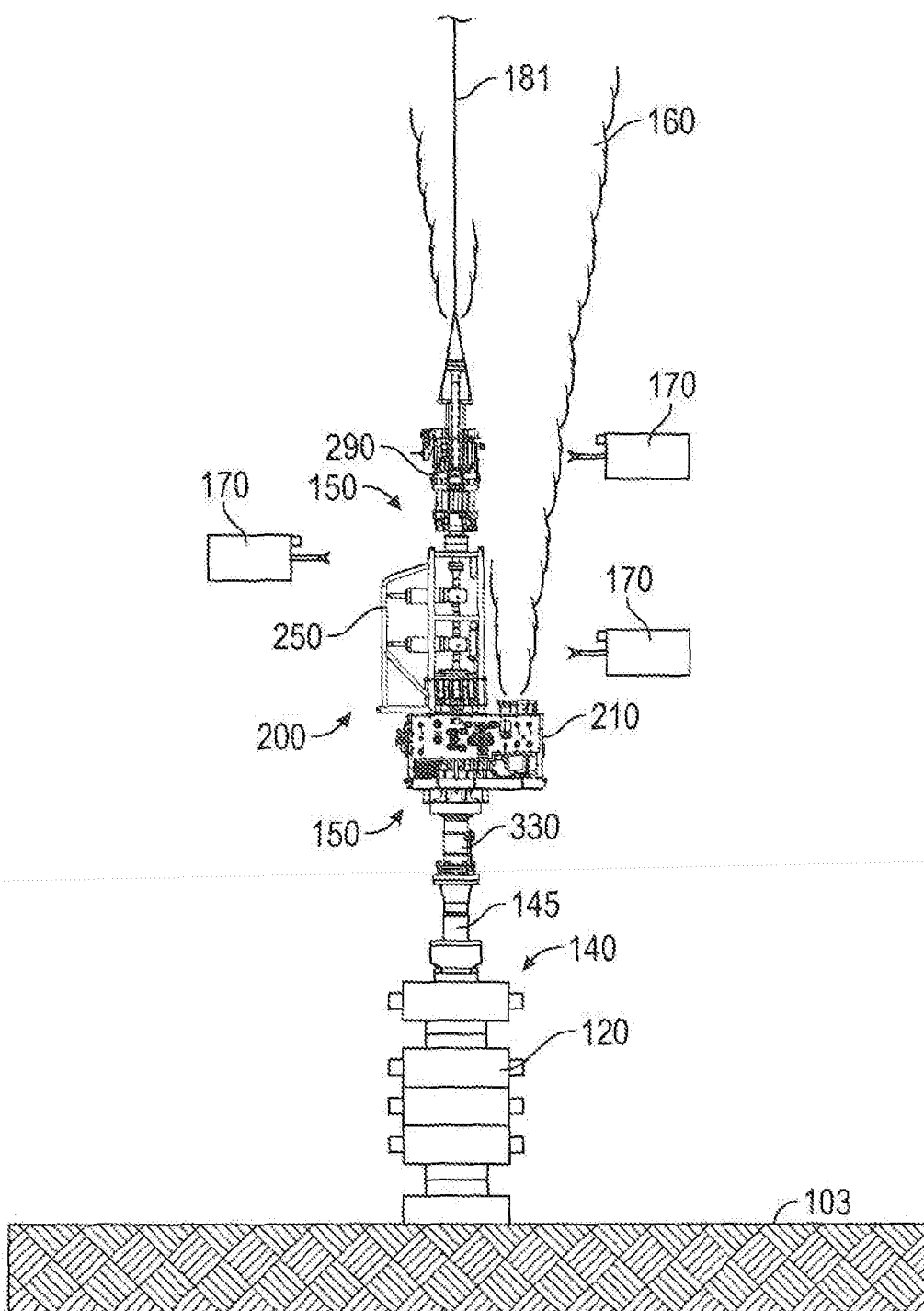
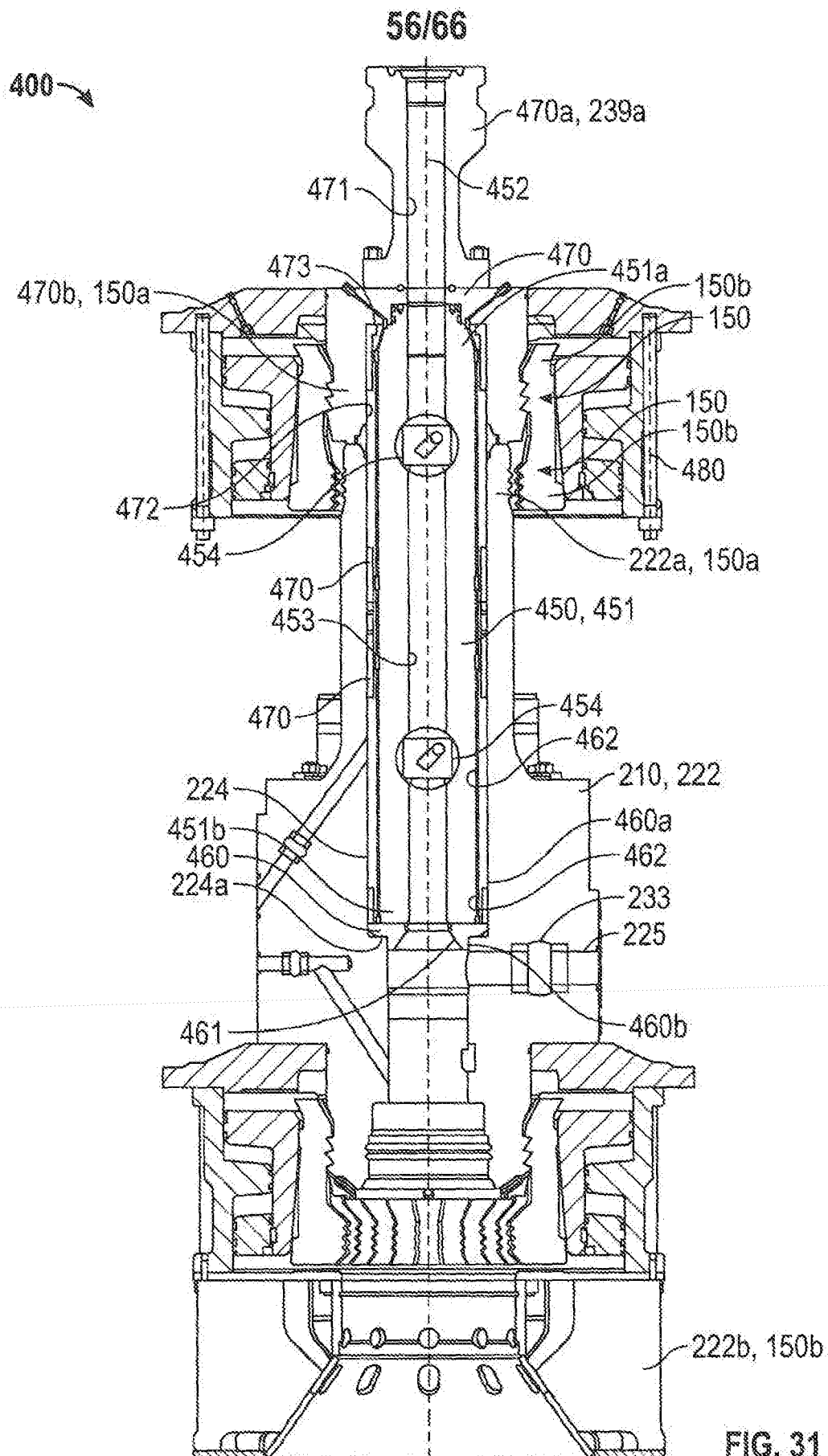
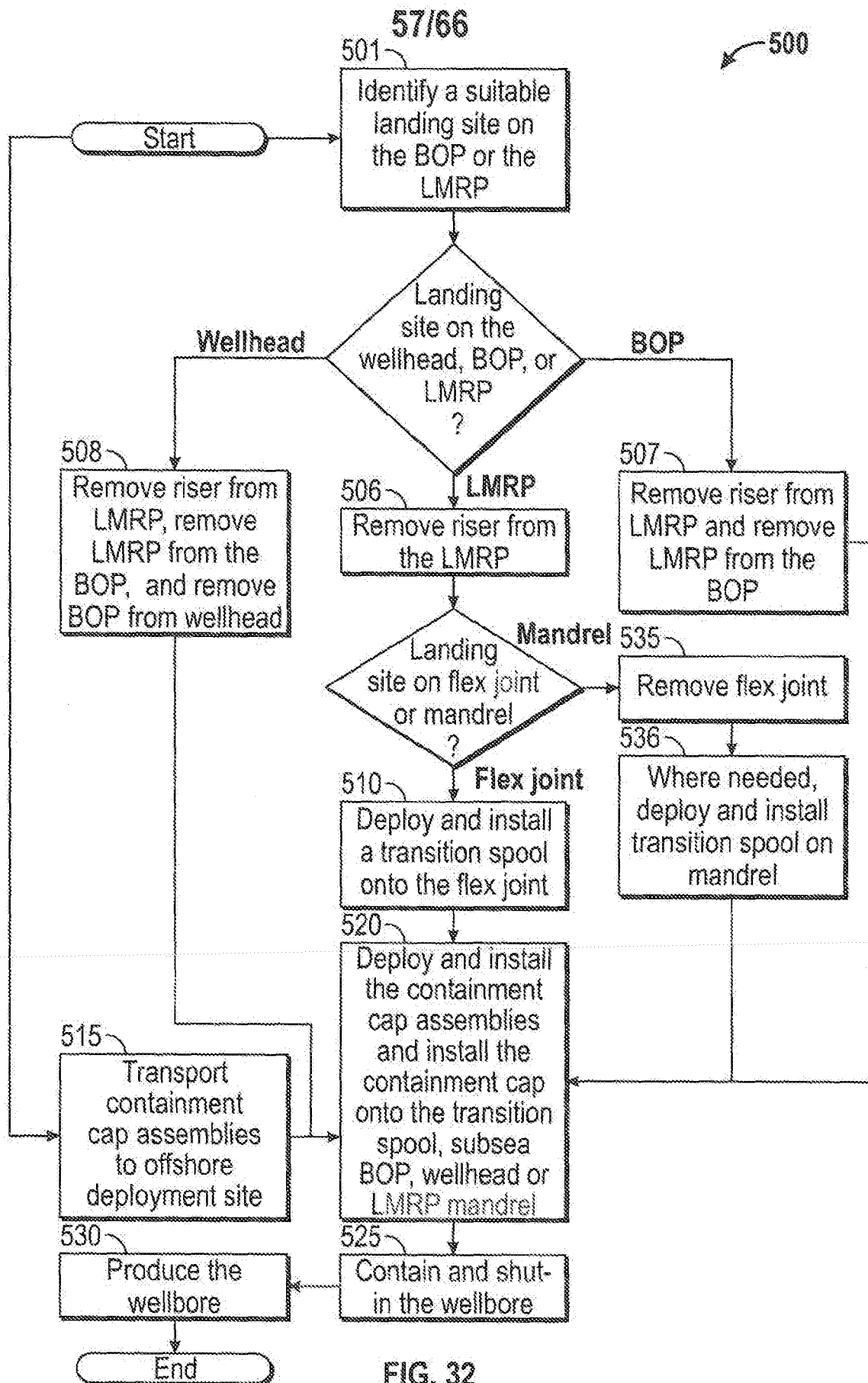


FIG. 30P





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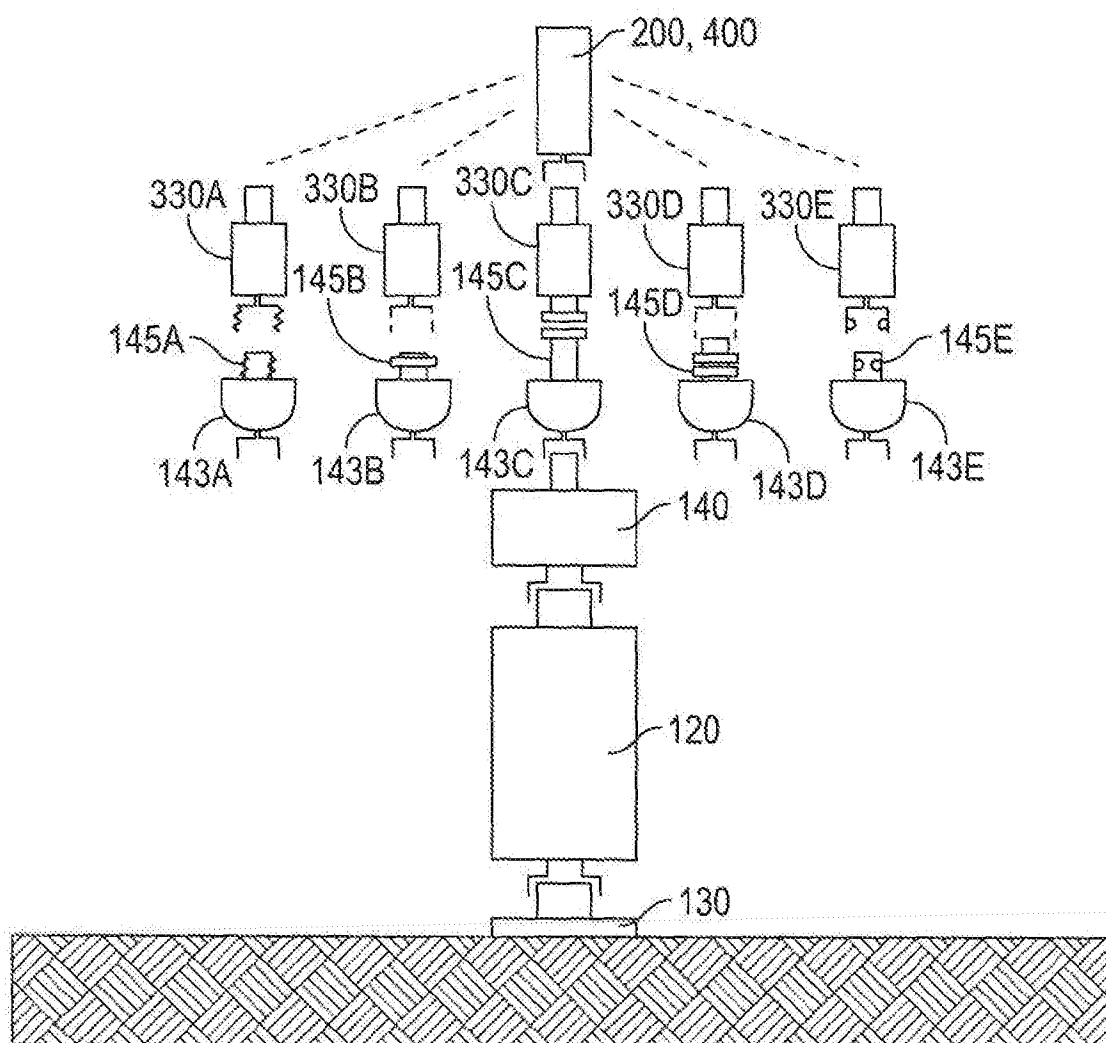


FIG. 33

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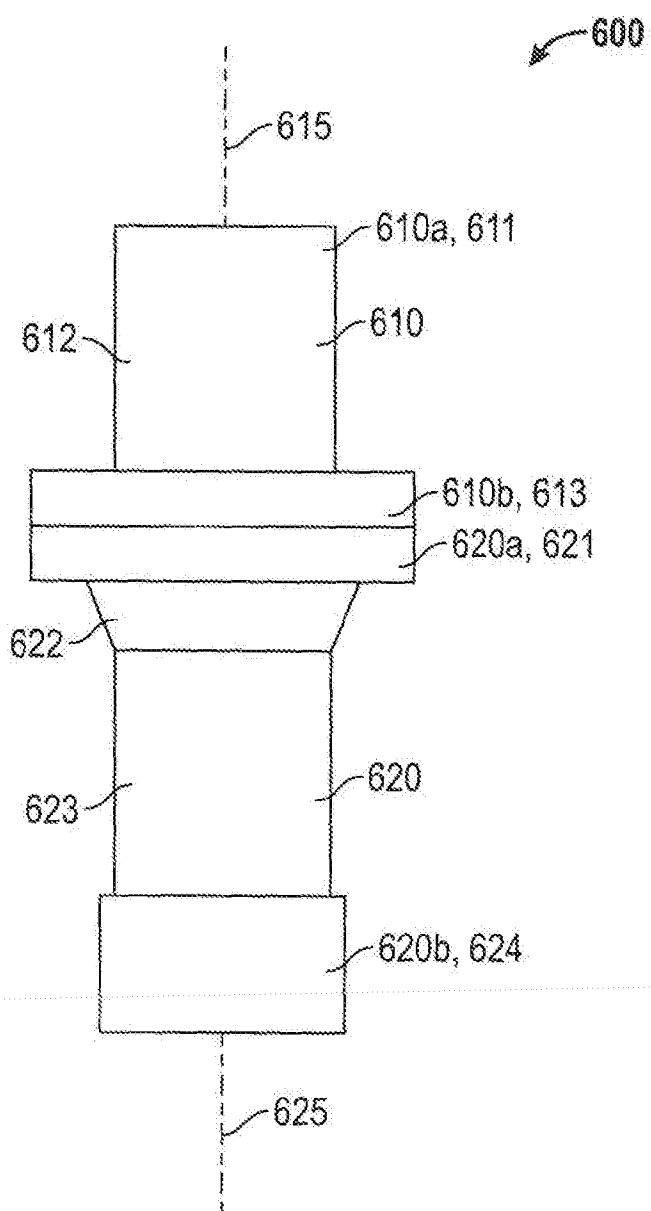


FIG. 34

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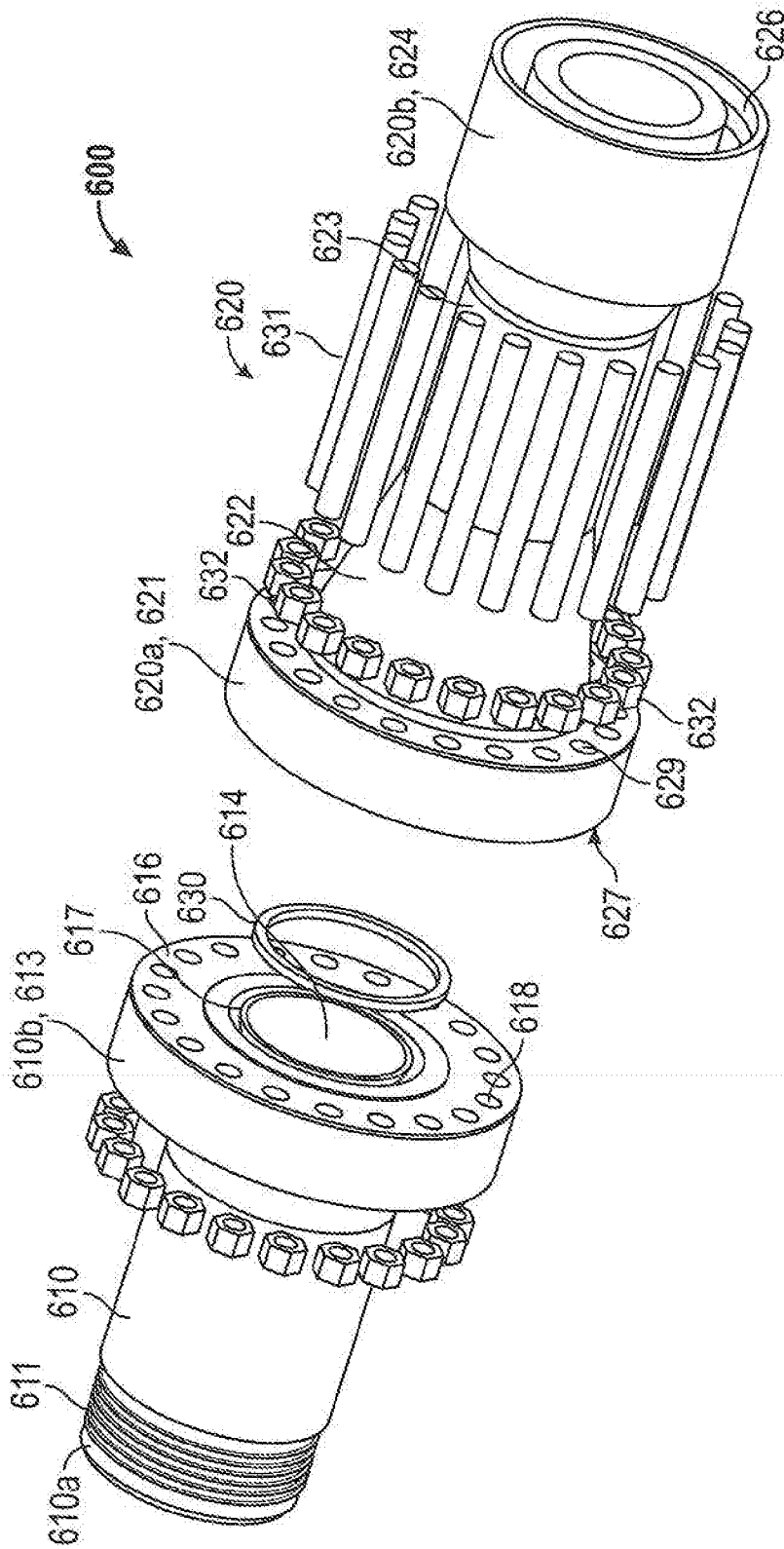
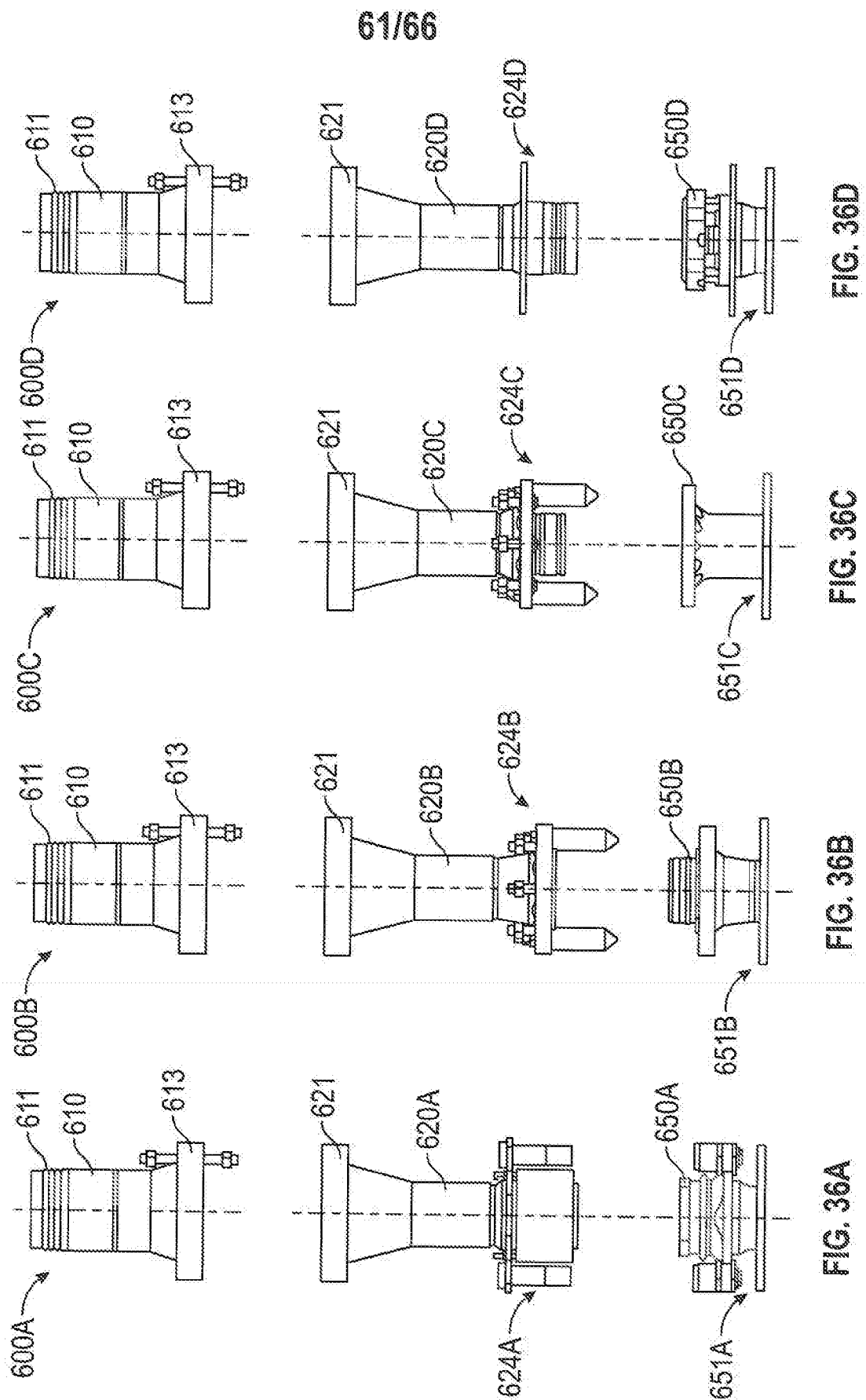
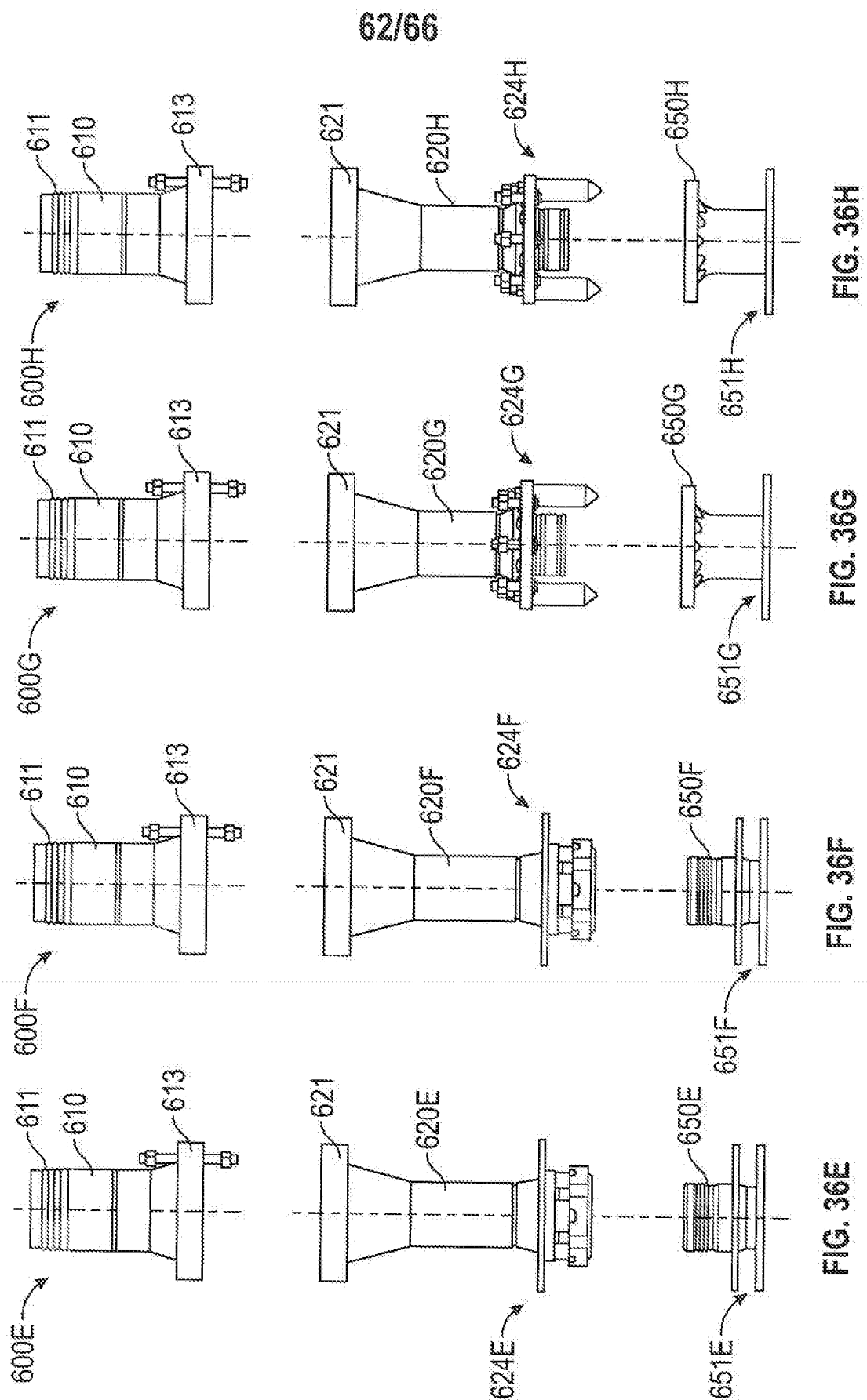


FIG. 35





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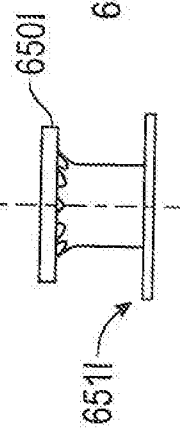
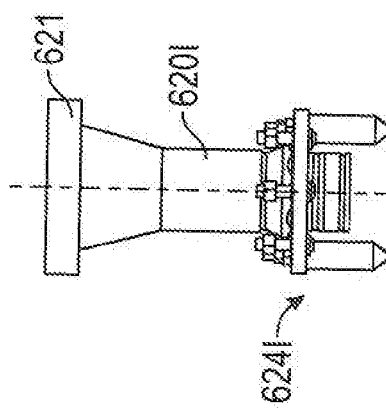
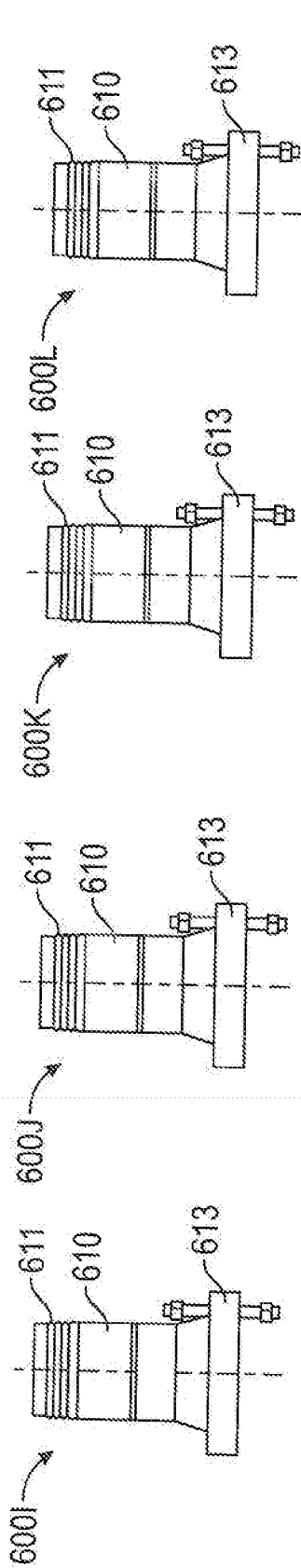


FIG. 36I

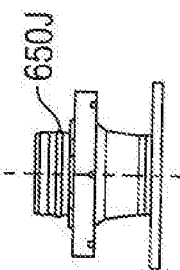
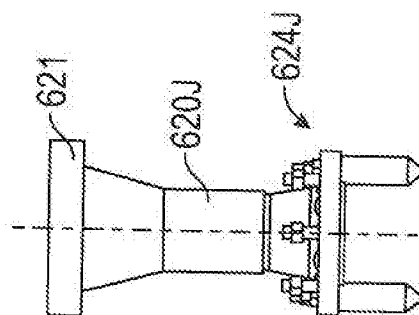
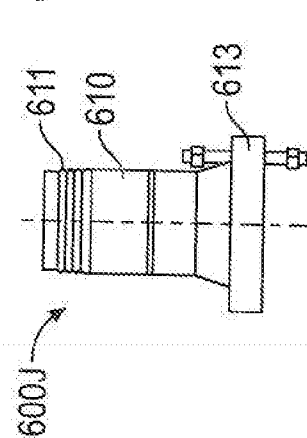


FIG. 36J

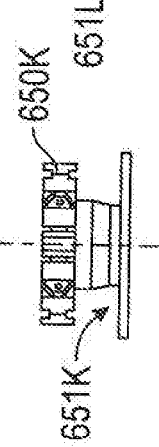
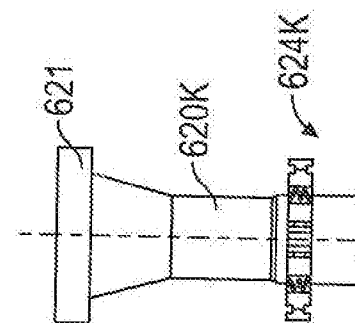
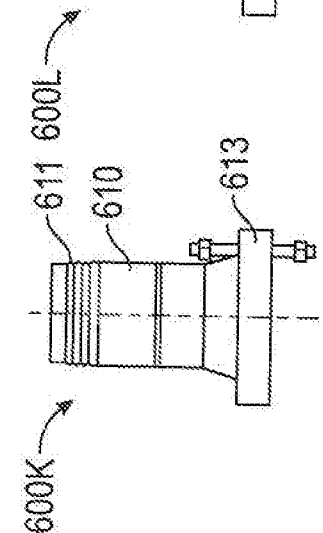


FIG. 36K

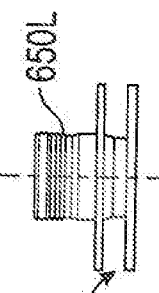
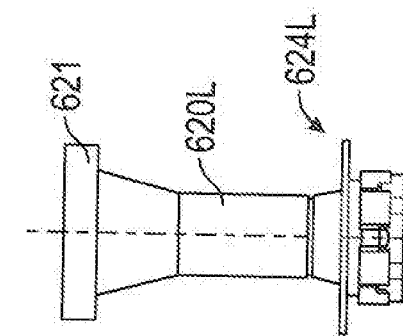
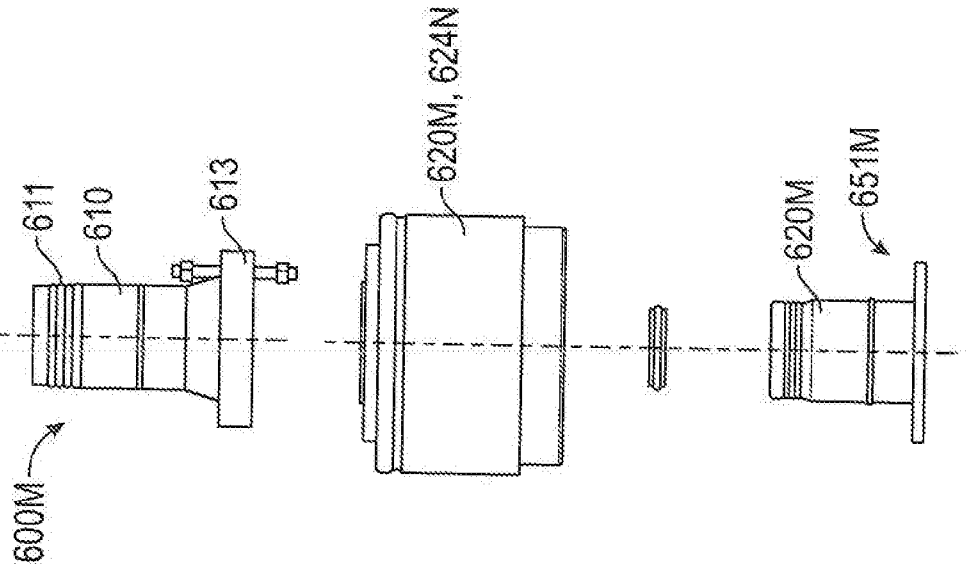
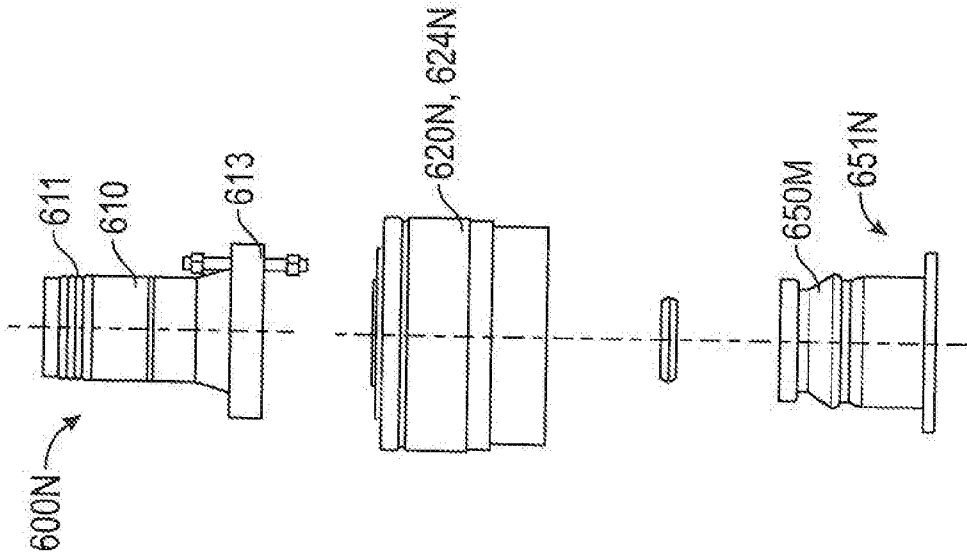


FIG. 36L



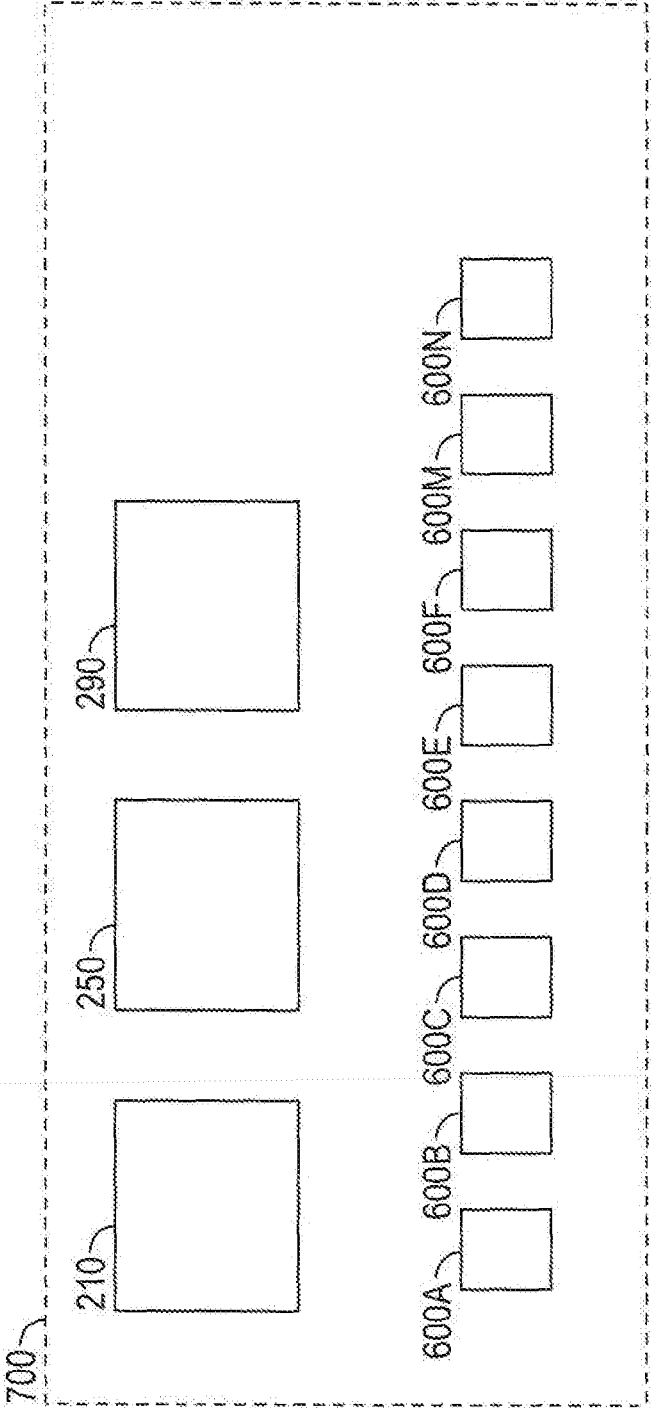


FIG. 37

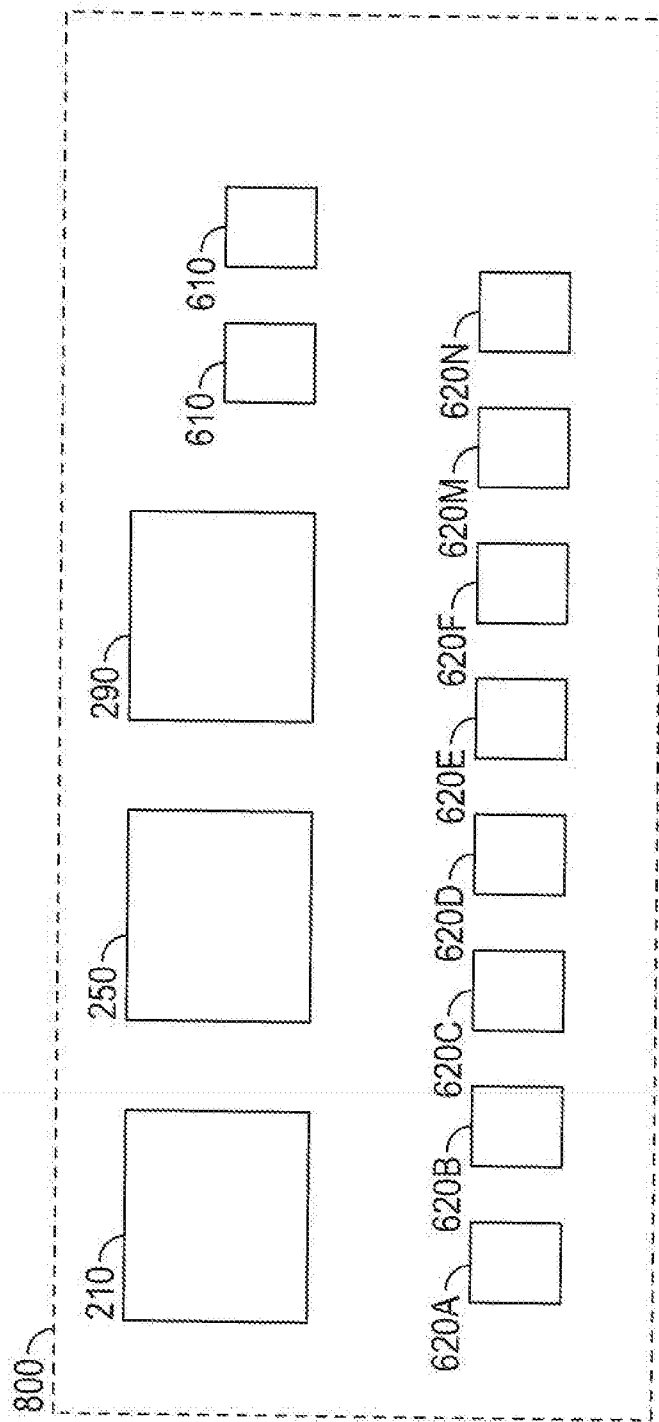


FIG. 38

INTERNATIONAL SEARCH REPORT

International application No

PCT/US2012/036908

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)

EP0-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	BP: "Kent Wells Technical Update Sealing Cap Installation", Internet 10 July 2010 (2010-07-10), pages 1-8, XP007921003, Retrieved from the Internet: URL:www.bp.com/liveassets/.../Press_QA_Slides_sealing_cap.pdf [retrieved on 2012-09-10] pages 3-6,8 the whole document ----- -/--	1-20



Further documents are listed in the continuation of Box C.



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Date of the actual completion of the international search

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INTERNATIONAL SEARCH REPORT

International application No

PCT/US2012/036908

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT		
Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	BP: "Deepwater Horizon Containment and Response: Harnessing Capabilities and Lessons Learned", Internet 1 September 2010 (2010-09-01), pages 1-84, XP007921001, Retrieved from the Internet: URL: www.bp.com/.../bp.../Deepwater_Horizon_Containment_Response [retrieved on 2012-09-10] ROV video's; pages 12,73 methanol injection and subsea use of bladders for dispersant; pages 9,26,27 -----	1