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Hoffman et al.

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(54) **EMERGENCY DISCONNECT SYSTEM FOR RISERLESS SUBSEA WELL INTERVENTION SYSTEM**

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CPC ***E21B 33/038*** (2013.01); ***E21B 33/035*** (2013.01)
USPC **166/351**; 166/338; 166/363; 166/341

(58) **Field of Classification Search**
CPC E21B 19/16
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See application file for complete search history.

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(57) **ABSTRACT**

A method for riserless intervention of a subsea well includes: lowering a pressure control assembly (PCA) from a vessel to a subsea production tree; fastening the PCA to the tree; lowering a control pod from the vessel to the PCA using an umbilical; fastening the control pod to the PCA; lowering an end of a fluid conduit from the vessel to the PCA; and fastening the fluid conduit to the PCA using a dry break connection.

14 Claims, 14 Drawing Sheets

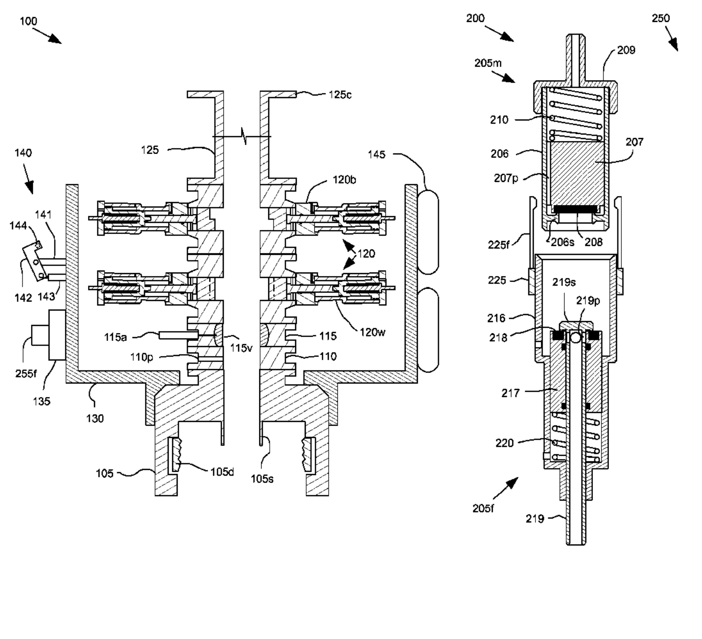

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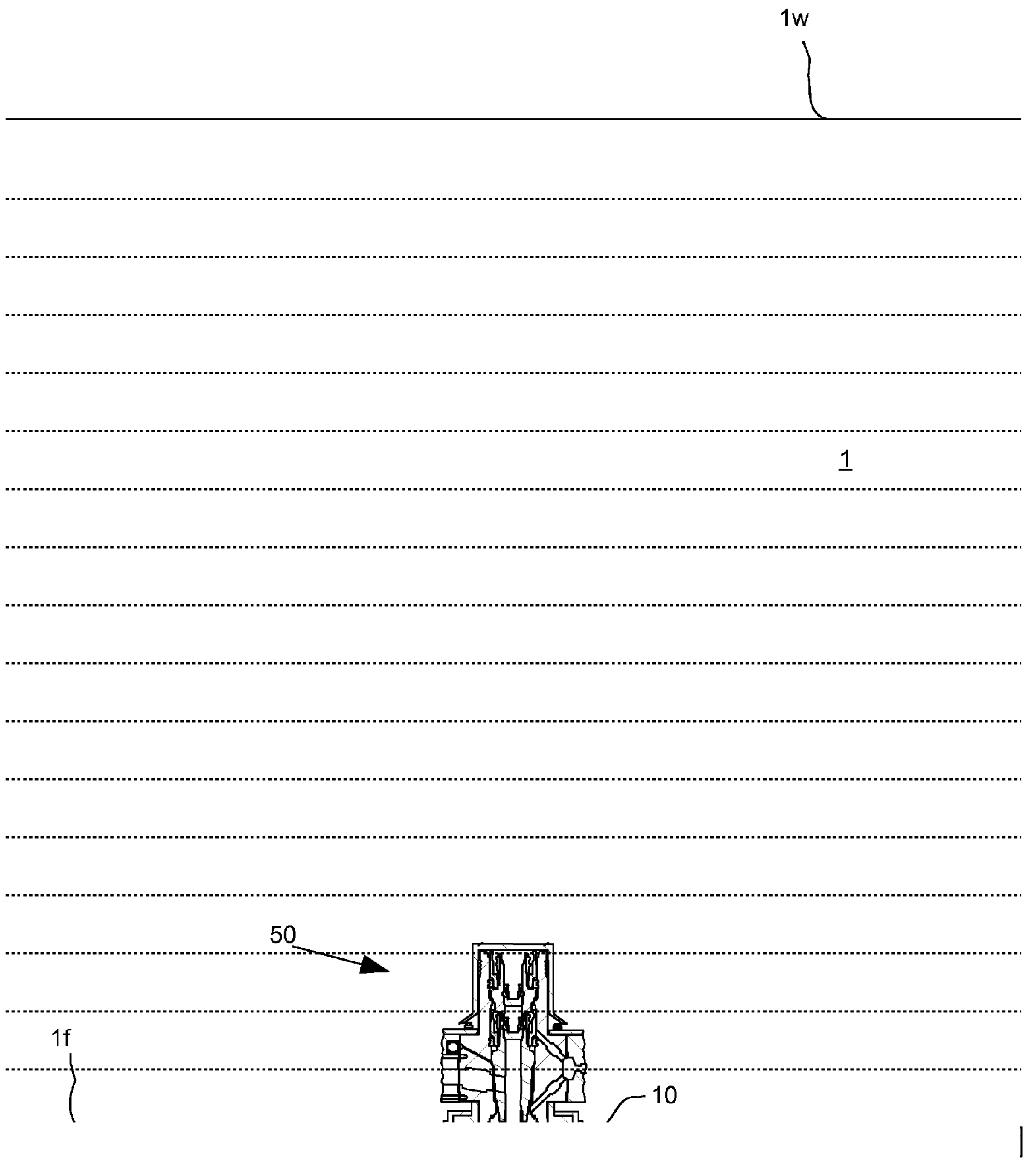
FIG. 1A
(Prior Art)



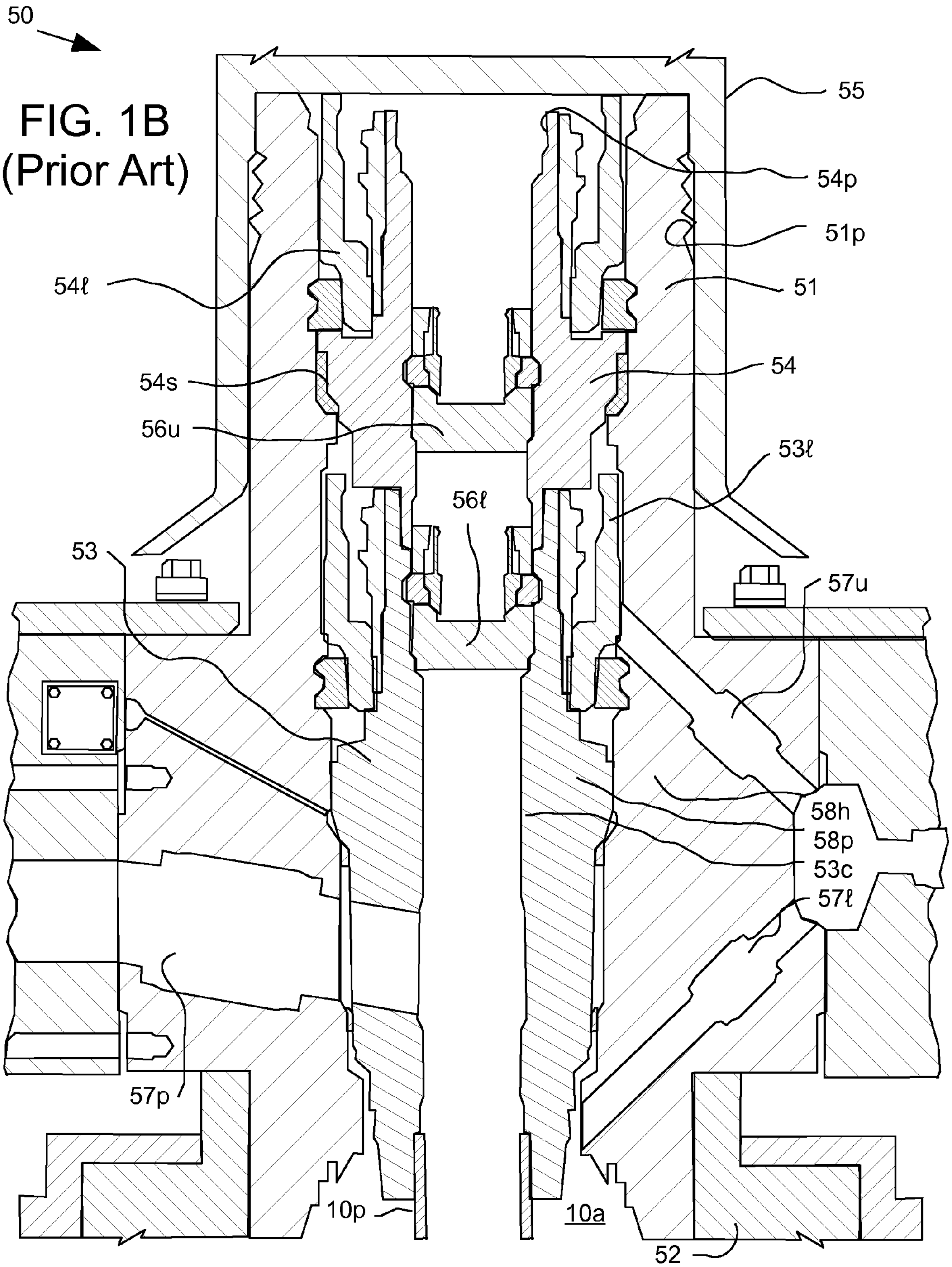
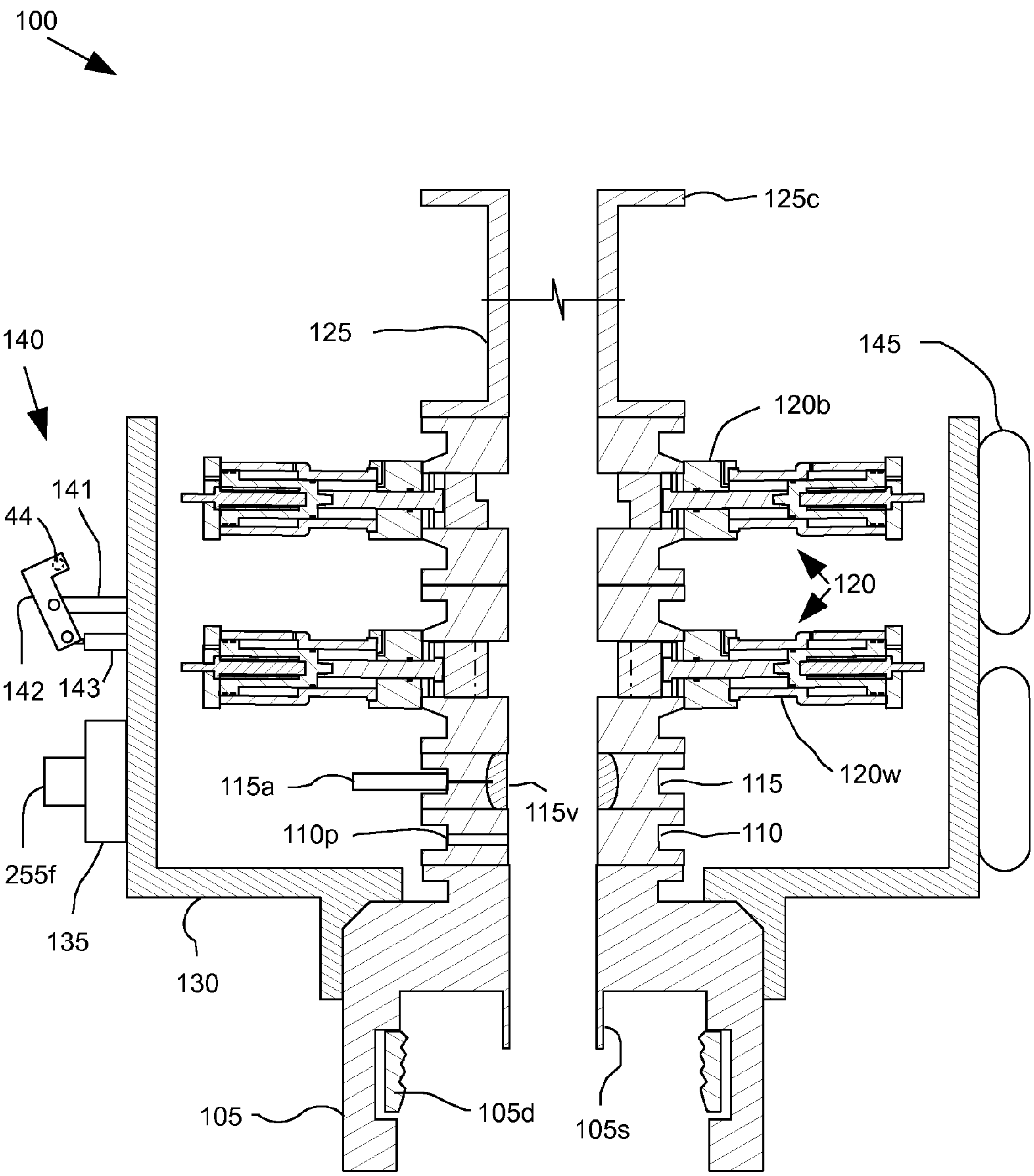


FIG. 1B
(Prior Art)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125c
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120b
141
144
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115v
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120w
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135
130
105
105d
105s

FIG. 2

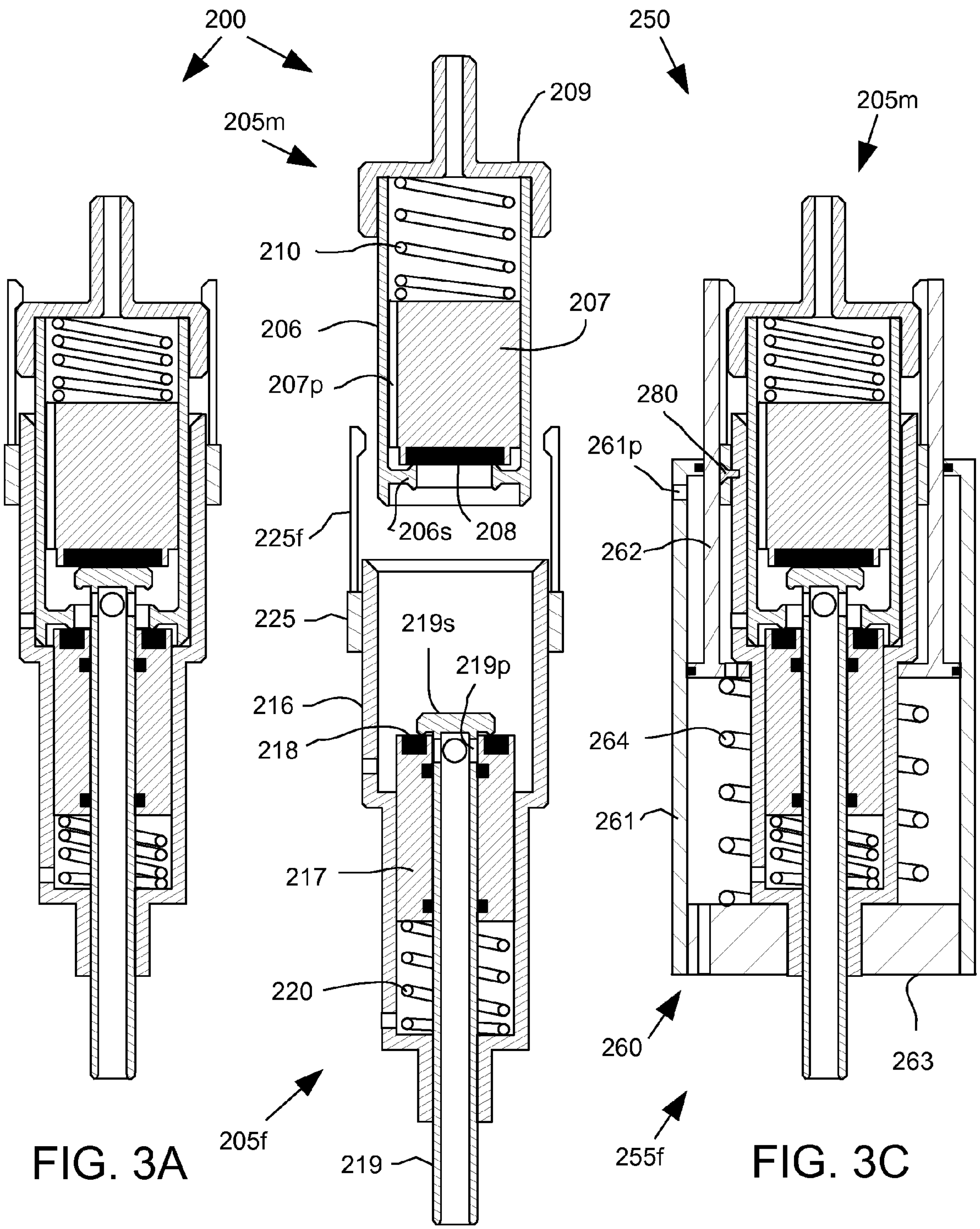
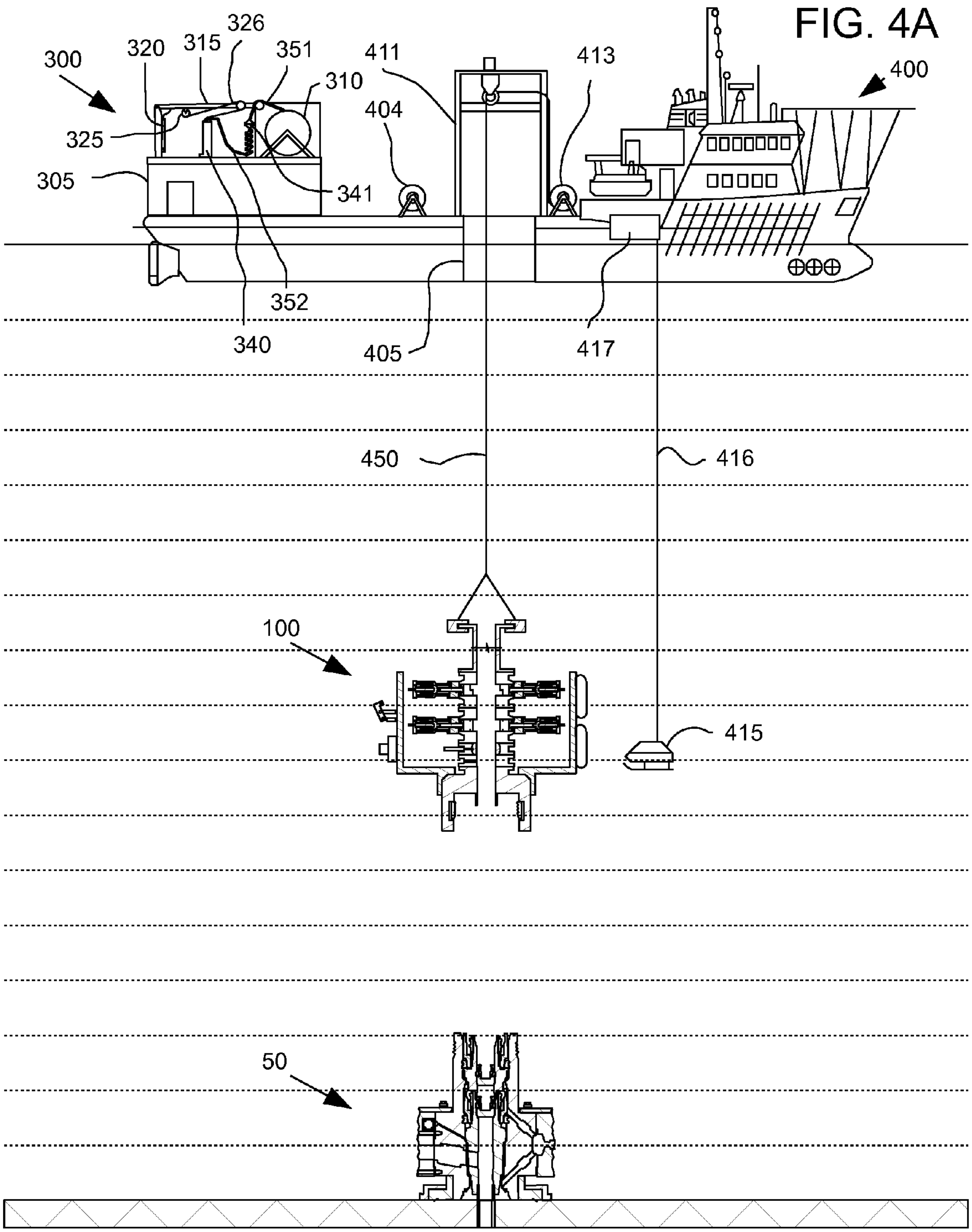


FIG. 3A

FIG. 3B

FIG. 3C

FIG. 4A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320
315
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310
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404
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305
341
352
340
405
417
450
416
100
415
50

FIG. 4B

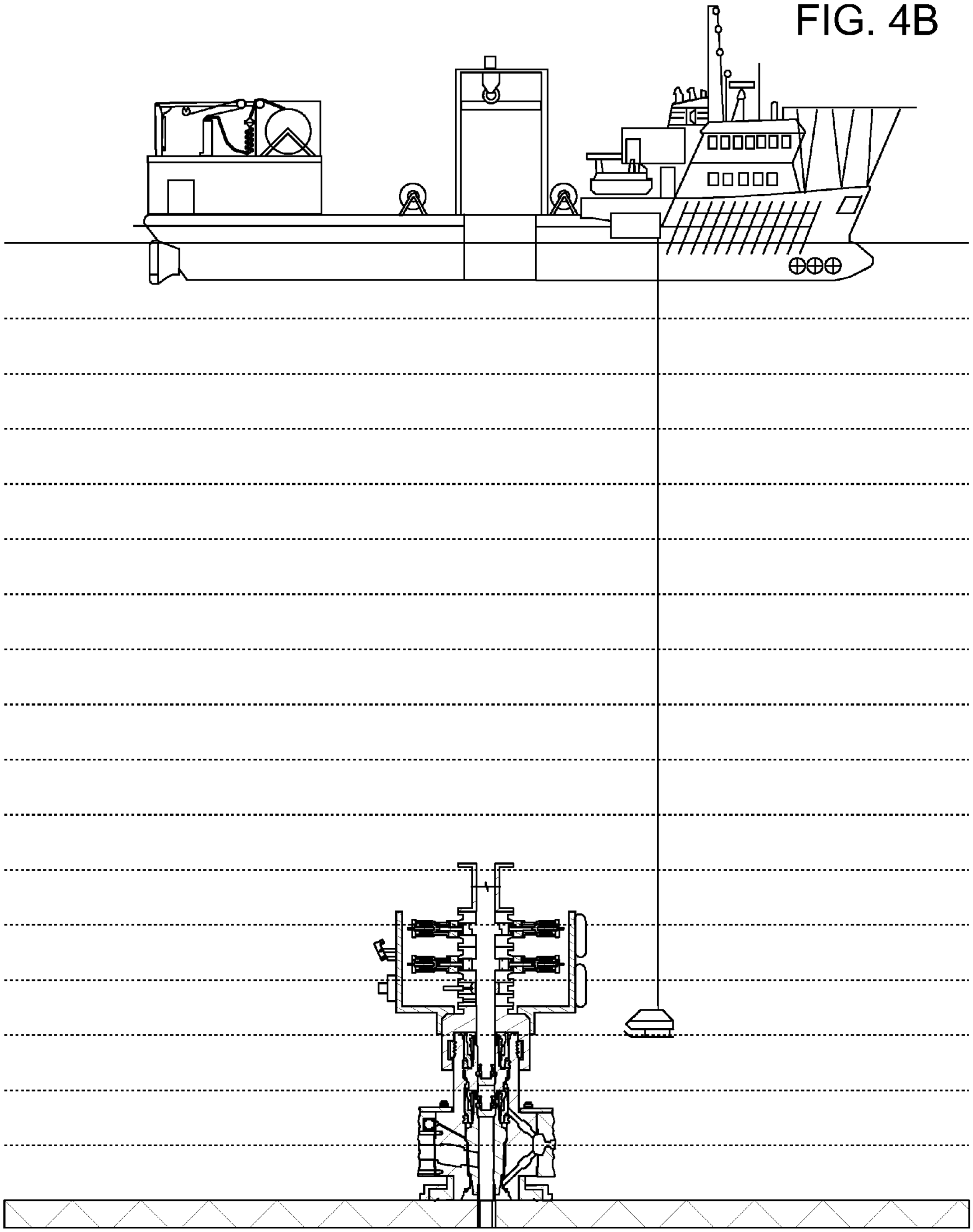


FIG. 4C

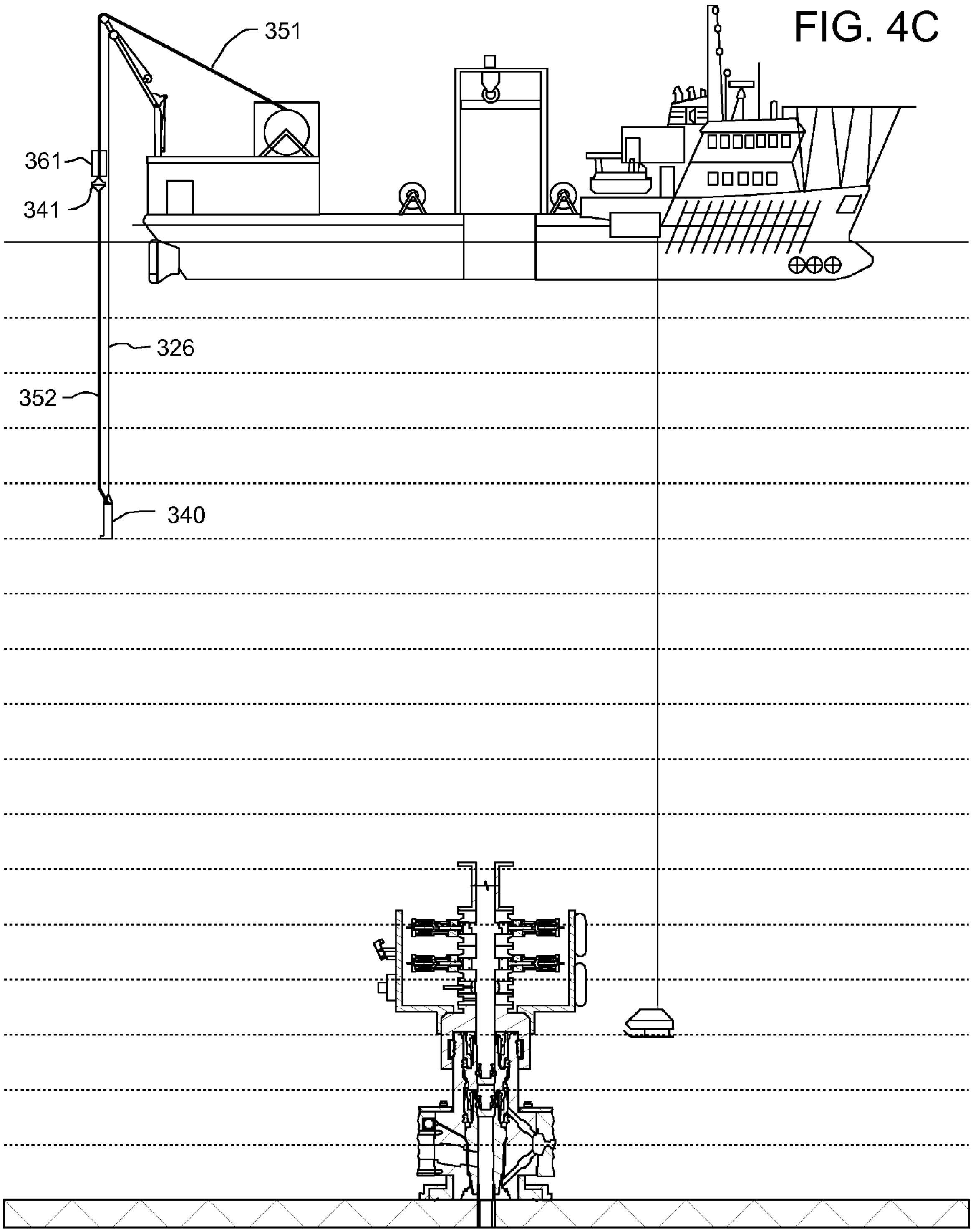
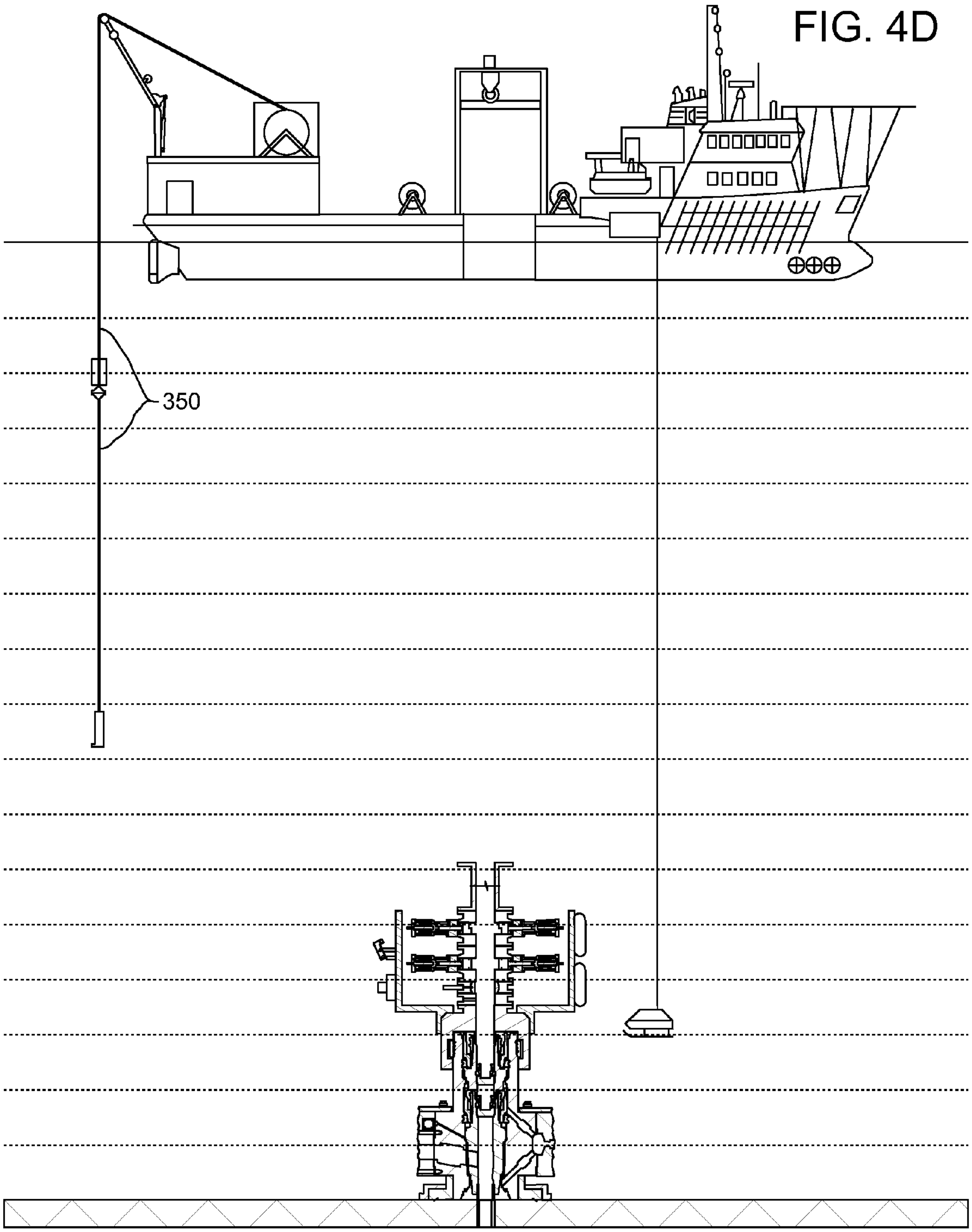


FIG. 4D



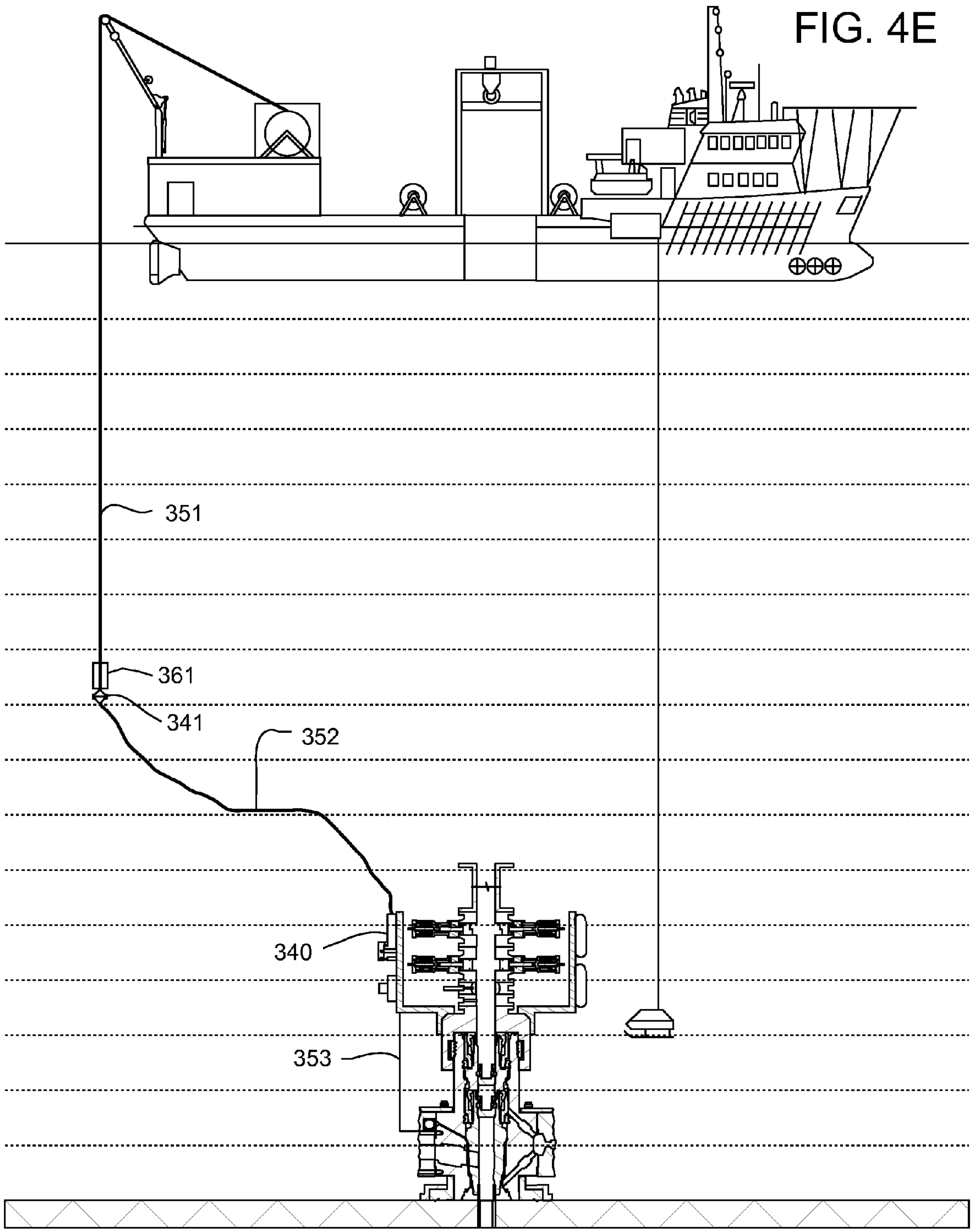


FIG. 4E

FIG. 4F

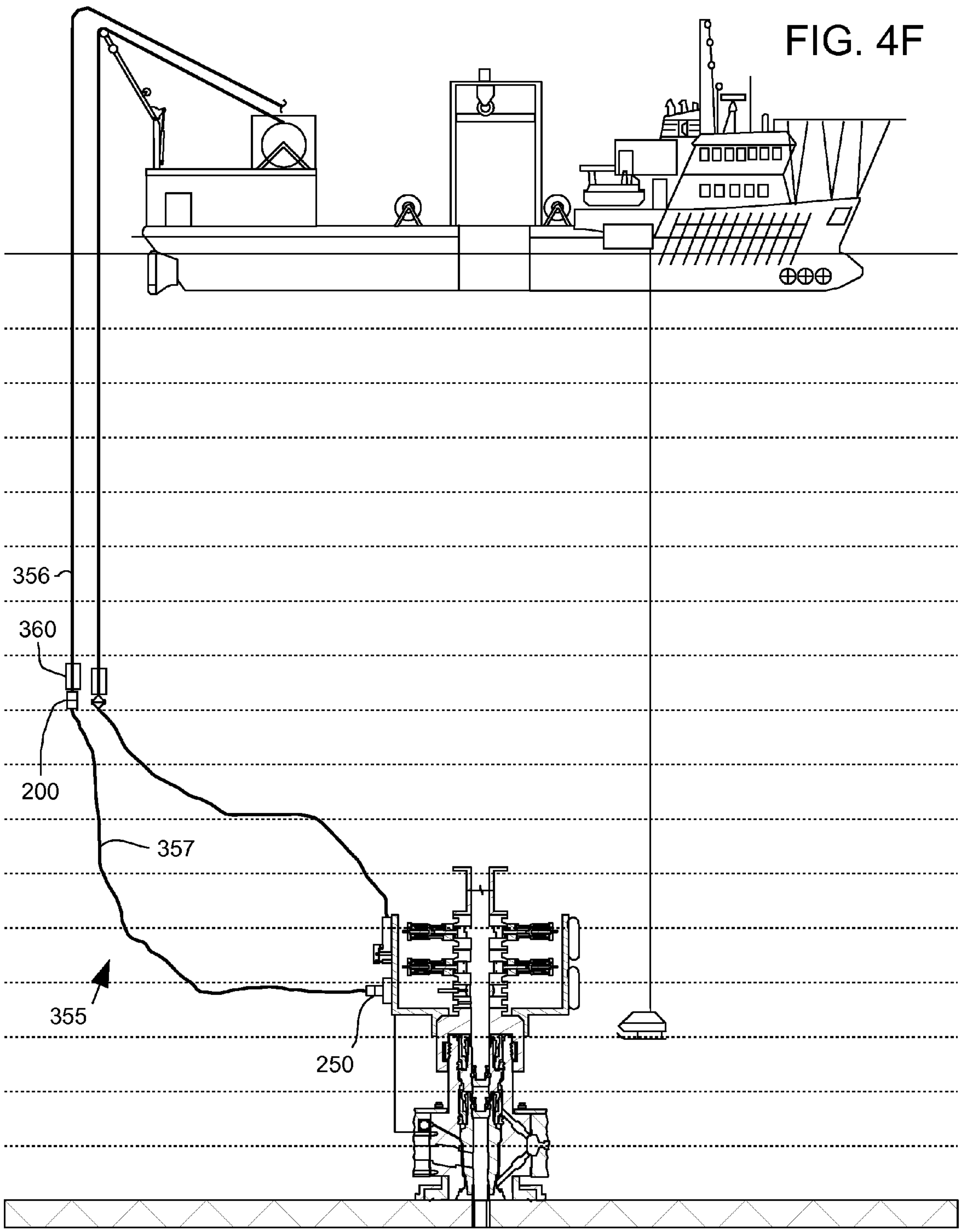
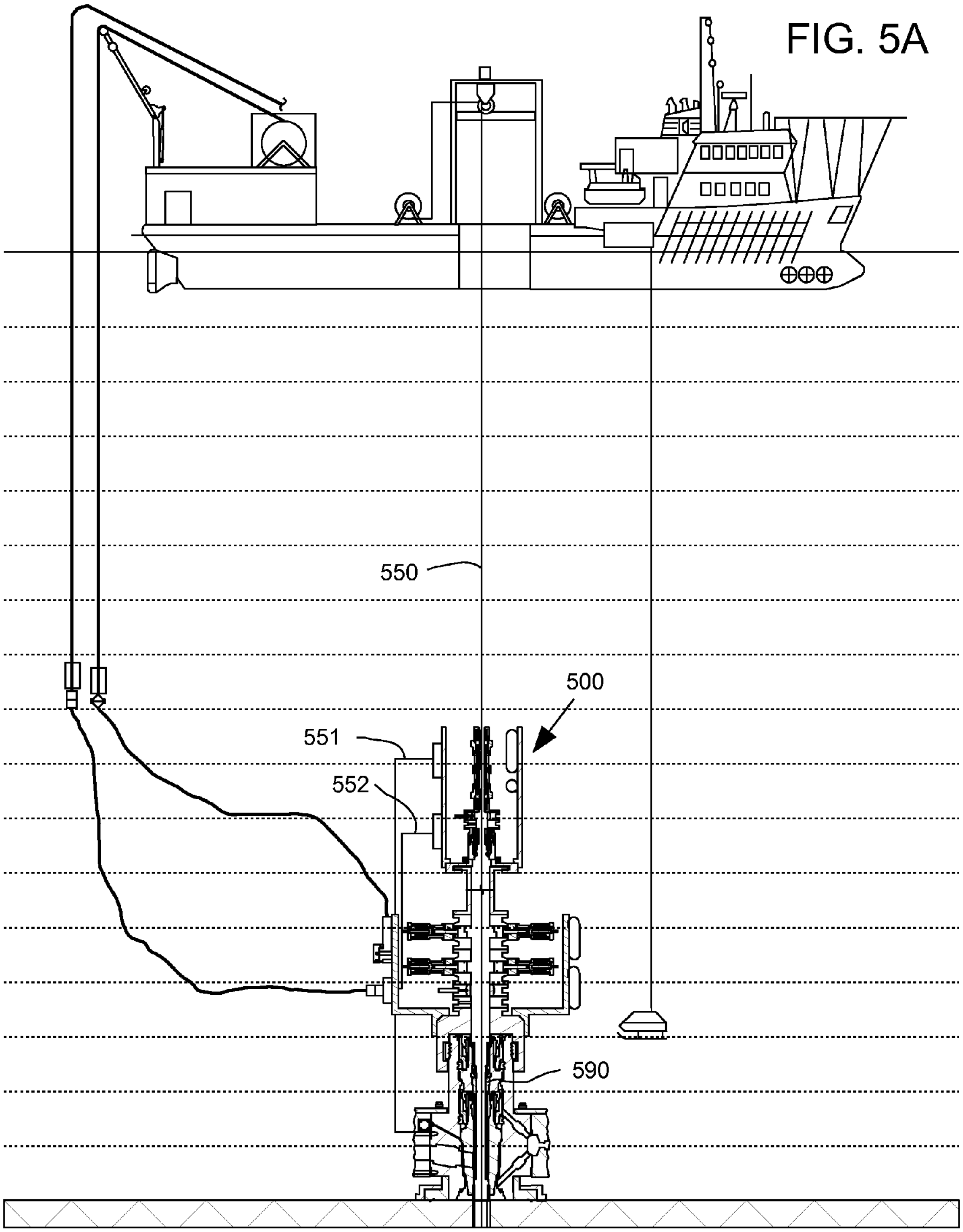


FIG. 5A



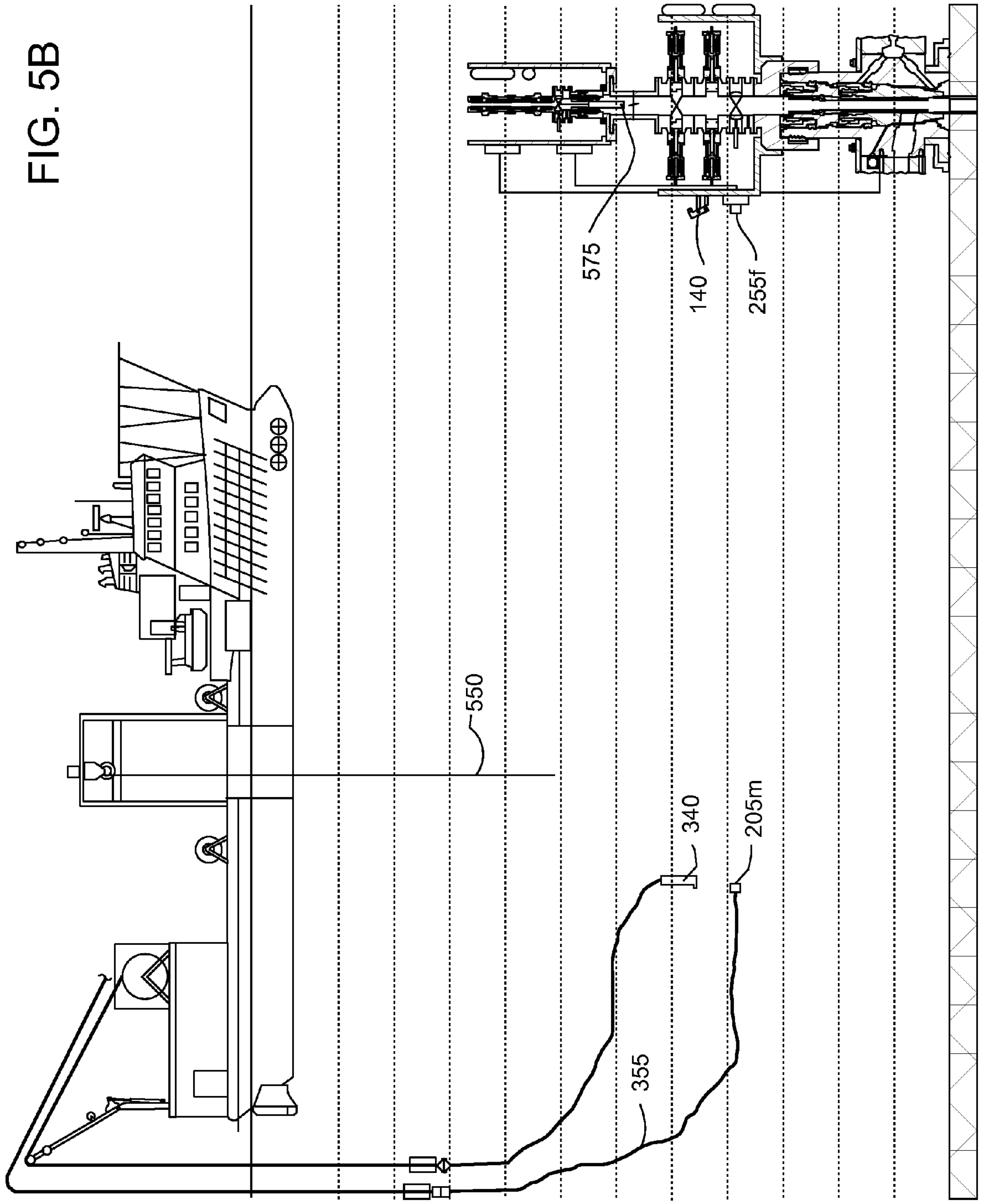


FIG. 5B

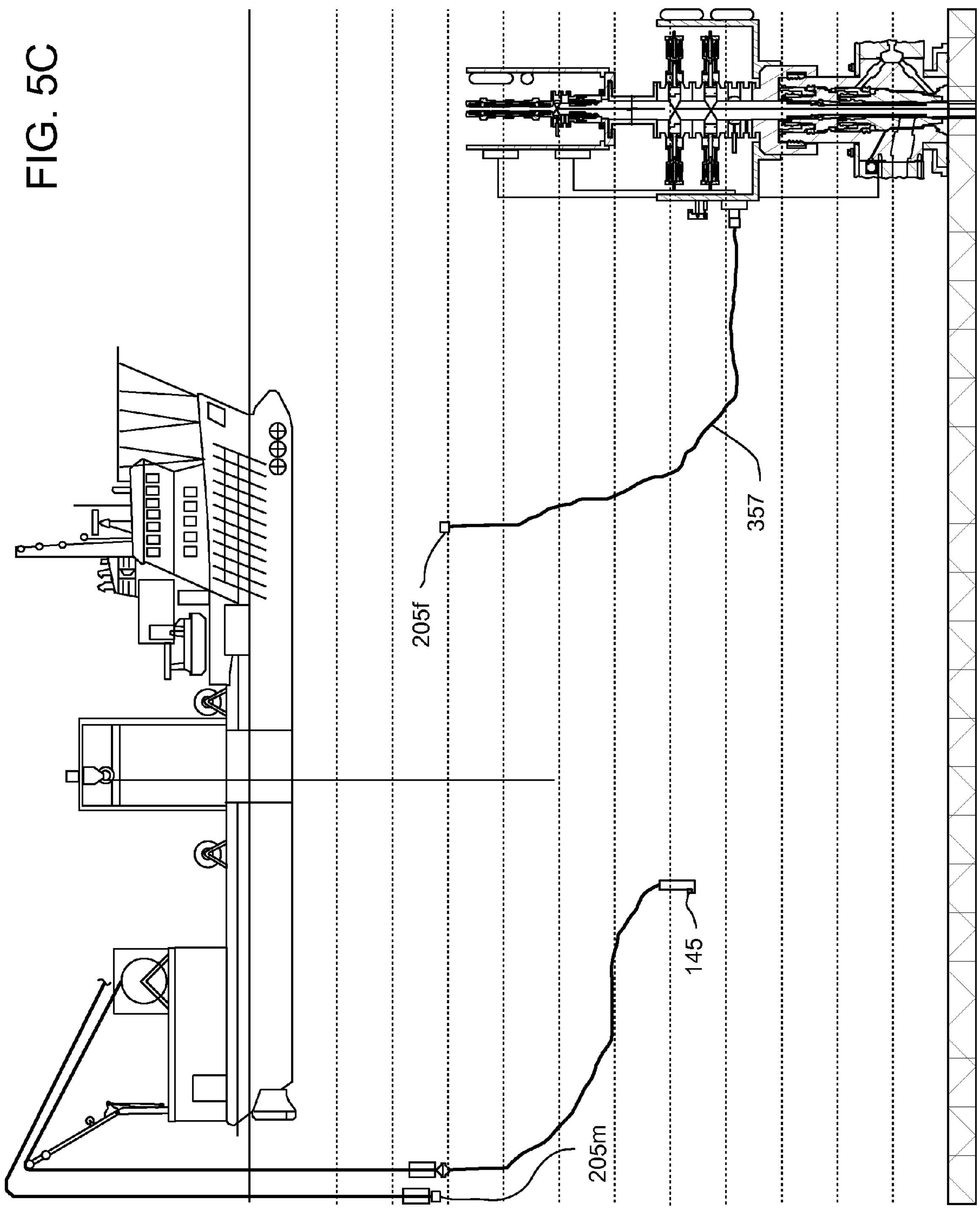
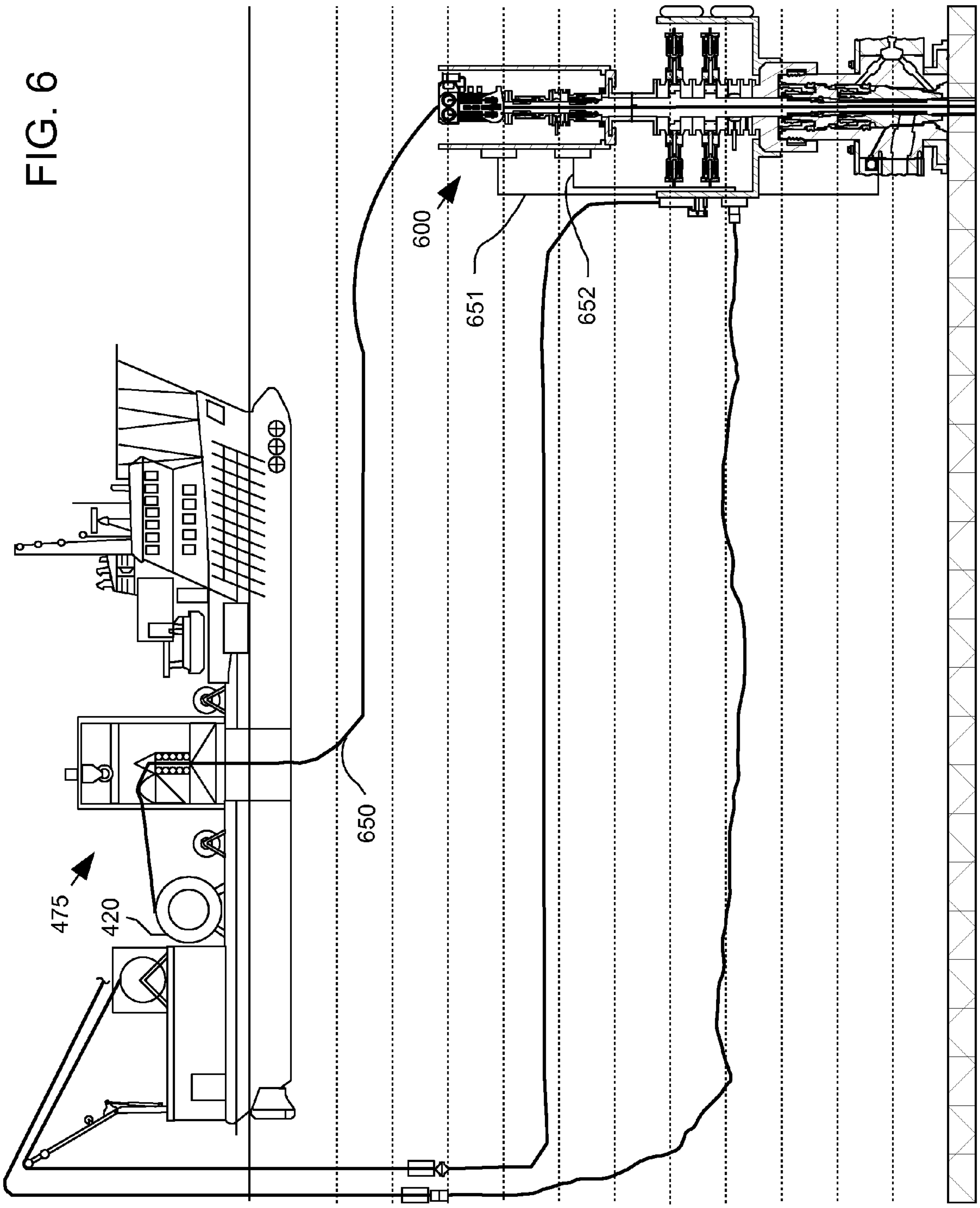


FIG. 5C

FIG. 6



EMERGENCY DISCONNECT SYSTEM FOR RISERLESS SUBSEA WELL INTERVENTION SYSTEM

BACKGROUND OF THE INVENTION

1. Field of the Invention

Embodiments of the present invention generally relate to an emergency disconnect system for a riserless subsea well intervention system.

2. Description of the Related Art

Subsea crude oil and/or natural gas wells frequently require workover to maintain adequate production. Workover operations may include perforating, gravel packing, production stimulation and repair of a downhole completion or production tubing. During the workover, specialized tools are lowered into the well by means of a wireline and winch. This wireline winch is typically positioned on the surface and the workover tool is lowered into the well through a lubricator and blowout preventer (BOP). Workover operations on subsea wells require specialized intervention equipment to pass through the water column and to gain access to the well. The system of valves on the wellhead is commonly referred to as a production or Christmas tree and the intervention equipment is attached to the tree with a blowout preventer (BOP).

The commonly used method for accessing a subsea well first requires installation of a BOP with a pre-attached tree running tool (TRT) for guiding the BOP to correctly align and interface with the tree. The BOP/running tool is lowered from a derrick that is mounted on a mobile offshore drilling unit (MODU), such as a drill ship or semi-submersible platform. The BOP/TRT is lowered on a segmented length of pipe called a workover riser string. The BOP/TRT is lowered by adding sections of pipe to the riser string until the BOP/TRT is sufficiently deep to allow landing on the tree. After the BOP is attached to the tree, the workover tool is lowered into the well through a lubricator mounted on the top of the riser string. The lubricator provides a sealing system at the entrance of the wireline that maintains the pressure and fluids inside the well and the riser string. The main disadvantage of this method is the large, specialized MODU that is required to deploy the riser string and the riser string needed to deploy the BOP.

FIG. **1**A illustrates a prior art completed subsea well. A wellbore **10** has been drilled from a floor if of the sea **1** into a hydrocarbon-bearing (i.e., crude oil and/or natural gas) reservoir (not shown). A string of casing (not shown) has been run into the wellbore and set therein with cement (not shown). The casing has been perforated to provide to provide fluid communication between the reservoir and a bore of the casing. A wellhead (not shown) has been mounted on an end of the casing string. A string of production tubing **10***p* (see FIG. **1**B) may extend from the wellhead (not shown) to the formation to transport production fluid from the formation to the seafloor **1***f*. A packer (not shown) may be set between the production tubing **10***p* and the casing to isolate an annulus **10***a* (see FIG. **1**B) formed between the production tubing **10***p* and the casing (not shown) from production fluid.

FIG. **1**B illustrates a prior art horizontal production tree **50**. The production tree **50** may be connected to the wellhead, such as by a collet, mandrel, or clamp tree connector. The tree **50** may be vertical or horizontal. If the tree is vertical (not shown), it may be installed after the production tubing **10***p* is hung from the wellhead. If the tree **50** is horizontal (as shown), the tree may be installed and then the production tubing **10***p* may be hung from the tree **50**. The tree **50** may include fittings and valves to control production from the wellbore into a pipeline (not shown) which may lead to a production facility (not shown), such as a production vessel or platform. The tree **50** may also be in fluid communication with a hydraulic conduit (not shown) controlling a subsurface safety valve SSV **10***v* (not shown).

The tree **50** may include a head **51**, a wellhead connector **52**, a tubing hanger **53**, an internal cap **54**, an external cap **55**, an upper crown plug **56***u*, a lower crown plug **56***l*, a production valve **57***p*, and one or more annulus valves **57***u,l*. Each of the components **51**-**54** may have a longitudinal bore extending therethrough. The tubing hanger **53** and head **51** may each have a lateral production passage formed through walls thereof for the flow of production fluid. The tubing hanger **53** may be disposed in the head bore. The tubing hanger **53** may support the production tubing **10***p*. The tubing hanger **53** may be fastened to the head by a latch **53***l*. The latch **53***l* may include one or more fasteners, such as dogs, and an actuator, such as a cam sleeve. The cam sleeve may be operable to push the dogs outward into a profile formed in an inner surface of the tree head **51**. The latch **53***l* may further include a collar for engagement with a running tool (not shown) for installing and removing the tubing hanger **53**.

The tubing hanger **53** may be rotationally oriented and longitudinally aligned with the tree head **51**. The tubing hanger **53** may further include seals **53***s* disposed above and below the production passage and engaging the tree head inner surface. The tubing hanger **53** may also have a number of auxiliary ports/conduits (not shown) spaced circumferentially there-around. Each port/conduit may align with a corresponding port/conduit (not shown) in the tree head **51** for communicating hydraulic fluid or electricity for various purposes to tubing hanger **53**, and from tubing hanger **53** downhole, such as for operation of the SSV. The tubing hanger **53** may have an annular, partially spherical exterior portion that lands within a partially spherical surface formed in tree head **51**.

The annulus **10***a* may communicate with an annulus passage formed through and along the head **51** for and bypassing the seals **53***s*. The annulus passage may be accessed by removing internal tree cap **54**. The tree cap **54** may be disposed in head bore above tubing hanger **53**. The tree cap **54** may have a downward depending isolation sleeve received by an upper end of tubing hanger **53**. Similar to the tubing hanger **53**, the tree cap **54** may include a latch **54***l* fastening the tree cap to the head **51**. The tree cap **54** may further include a seal **54***s* engaging the head inner surface. The production valve **57***p* may be disposed in the production passage and the annulus valves **57***u,l* may be disposed in the annulus passage. Ports/conduits (not shown) may extend through the tree head **51** to a tree controller (not shown) for electrical or hydraulic operation of the valves.

The upper crown plug **56***u* may be disposed in tree cap bore and the lower crown plug **56***l* may be disposed in the tubing hanger bore. Each crown plug **56***u,l* may have a body with a metal seal on its lower end. The metal seal may be a depending lip that engages a tapered inner surface of the respective cap and hanger. The body may have a plurality of windows which allow fasteners, such as dogs, to extend and retract. The dogs may be pushed outward by an actuator, such as a central cam. The cam may have a profile on its upper end. The cam may move between a lower locked position and an upper position freeing dogs to retract. A retainer may secure to the upper end of body to retain the cam.

SUMMARY OF THE INVENTION

Embodiments of the present invention generally relate to an emergency disconnect system for a riserless subsea well intervention system. In one embodiment, a method for riserless intervention of a subsea well includes: lowering a pressure control assembly (PCA) from a vessel to a subsea production tree; fastening the PCA to the tree; lowering a control pod from the vessel to the PCA using an umbilical; fastening the control pod to the PCA; lowering an end of a fluid conduit from the vessel to the PCA; and fastening the fluid conduit to the PCA using a dry break connection.

In another embodiment, a pressure control assembly (PCA) for riserless intervention of a subsea well includes: a bore formed therethrough; a production tree adapter having a connector for fastening the PCA to a subsea production tree and a seal sleeve for engaging an internal profile of the tree; a frame connected to the adapter; a fluid sub connected to the adapter and having a port in communication with the bore; an isolation valve connected to the fluid sub and operable to close the bore; a blow out preventer (BOP) connected to the isolation valve and operable to shear a workstring and close the bore; an accumulator for storing pressurized hydraulic fluid to operate the BOP; a tool housing connected to the blow out preventer; a control pod receptacle connected to the frame and having a base for receiving a control pod, a latch operable to engage the control pod, and an actuator for operating the latch; and a manifold connected to the frame and having a coupling of a dry break connection for receiving a mating coupling connected to a fluid conduit and operable to provide fluid communication between the fluid conduit and the bore.

BRIEF DESCRIPTION OF THE DRAWINGS

So that the manner in which the above recited features of the present invention can be understood in detail, a more particular description of the invention, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this invention and are therefore not to be considered limiting of its scope, for the invention may admit to other equally effective embodiments.

FIG. **1**A illustrates a prior art completed subsea well. FIG. **1**B illustrates a prior art horizontal production tree.

FIG. **2** illustrates a pressure control assembly (PCA), according to one embodiment of the present invention.

FIG. **3**A illustrates a passive dry-break connection, according to another embodiment of the present invention. FIG. **3**B illustrates couplings of the connection disconnected. FIG. **3**C illustrates an actuated dry-break connection, according to another embodiment of the present invention.

FIG. **4**A illustrates deployment of the PCA to the subsea production tree, according to another embodiment of the present invention. FIG. **4**B illustrates connection of the PCA to the tree. FIGS. **4**C and **4**D illustrate deployment of a control pod to the PCA using an umbilical. FIG. **4**E illustrates connection of the control pod to the PCA. FIG. **4**F illustrates deployment and connection of a fluid conduit to the tree.

FIG. **5**A illustrates an intervention operation being conducted using a wireline module connected to the PCA, according to another embodiment of the present invention. FIG. **5**B illustrates emergency disconnection from the PCA in response to a minor emergency. FIG. **5**C illustrates emergency disconnection from the PCA in response to a major emergency.

FIG. **6** illustrates an intervention operation being conducted using a coiled tubing module connected to the PCA, according to another embodiment of the present invention.

DETAILED DESCRIPTION

FIG. **2** illustrates a pressure control assembly (PCA) **100**, according to one embodiment of the present invention. The PCA **100** may include a tree adapter **105**, a fluid sub **110**, an isolation valve **115**, a blow out preventer (BOP) stack **120**, a tool housing (aka lubricator riser) **125**, a frame **130**, a manifold **135**, a pod receptacle **140**, and one or more accumulators **145** (two shown). The tree connector **105**, fluid sub **110**, isolation valve **115**, BOP stack **120**, and tool housing **125** may each include a housing or body having a longitudinal bore therethrough and be connected, such as by flanges, such that a continuous bore is maintained therethrough. The bore may have a large drift diameter, such as greater than or equal to four, five, six, or seven inches to accommodate a bottom hole assembly (BHA) of a workstring (discussed more below) and the crown plugs **56***u,l* of the tree **50**.

The tree adapter **105** may include a connector, such as dogs **105***d*, for fastening the PCA **100** to an external profile **51***p* of the tree **50** and a seal sleeve **105***s* for engaging an internal profile **54***p* of the tree. The tree adapter **105** may further include an electric or hydraulic actuator and an interface, such as a hot stab, so that a remotely operated subsea vehicle (ROV) **415** (see FIG. **4**A) may operate the actuator for engaging the dogs **105***d* with the external profile **51***p*. The frame **130** may be connected to the tree connector **50**, such as by fasteners (not shown). The manifold **135** may be fastened to the frame **130**. The fluid sub **110** may include a housing having a bore therethrough and a port **110***p* in communication with the bore. The port **110***p* may be in fluid communication with the manifold **135** via a conduit (not shown).

The isolation valve **115** may include a housing, a valve member **115***v* disposed in the housing bore and operable between an open position and a closed position, and an actuator **115***a* operable to move the valve member between the positions. The actuator **115***a* may be electric or hydraulic and may be in communication with a stab plate (not shown) of the pod receptacle **140**. The isolation valve **115** may further operate as a check valve in the closed position: allowing fluid flow downward from the tool housing into the wellbore and preventing reverse fluid flow therethrough. Alternatively, the isolation valve **115** may be bi-directional when closed, the PCA **100** may further include a bypass conduit (not shown) connected to a port of a drain sub (not shown) disposed between the isolation valve and the BOP stack, and the drain port may include a check valve allowing downward flow and preventing reverse flow.

The BOP stack **120** may include one or more hydraulically operated ram preventers **120***b,w*, such as a blind-shear preventer **120***b* and one or more workstring preventers **120***w*, such as a wireline preventer and a coiled tubing preventer (only one workstring preventer shown) connected together via bolted flanges. Each ram preventer **120***b,w* may include two opposed rams disposed within a body. The body may have a bore that is aligned with the wellbore. Opposed cavities may intersect the bore and support the rams as they move radially into and out of the bore. A bonnet may be connected to the body on the outer end of each cavity and may support an actuator that provides the force required to move the rams into and out of the bore. Each actuator may include a hydraulic piston to radially move each ram and a mechanical lock to maintain the position of the ram in case of hydraulic pressure loss. The lock may include a threaded rod, a motor (not shown) for rotationally driving the rod, and a threaded sleeve. Once each ram is hydraulically extended into the bore, the motor may be operated to push the sleeve into engagement with the piston. Each actuator may include single (shown) or dual pistons (not shown). The blind-shear preventer **120***b* may cut the workstring, such as coiled tubing, wireline, and even drill pipe, when actuated and seal the bore. The coiled tubing preventer may seal against an outer surface of coiled tubing when actuated and the wireline preventer may seal against an outer surface of the wireline when actuated.

The tool housing **125** may be of sufficient length to contain either a plug running tool (PRT) (not shown) or a BHA **575** (FIG. **5**B) so that the PCA **100** may be closed while deploying either a wireline module **500** (FIG. **5**A) or a coiled tubing module **600** (FIG. **6**.) The tool housing **125** may have a connector profile **125***c* for receiving an adapter of either workstring module **500**, **600**.

The pod receptacle **140** may be operable to receive a subsea control pod **340** (FIG. **4**A). The receptacle may include a base **141**, a latch **142**, and an actuator **143**. The base **141** be connected to the frame **130**, such as by fasteners, and may include a landing plate for supporting the pod **340**, a landing guide (not shown), such as a pin, and the stab plate. The stab plate may provide communication, such as electric (power and/or data), hydraulic, or optic, between the pod **340** and components of the PCA **100**. The latch **142** may be pivoted to the base **141**, such as by a fastener, and be movable by the actuator **143** between an engaged position (FIG. **4**D) and a disengaged position (shown). The actuator **143** may be a piston and cylinder assembly connected to the frame **135** and the receptacle **140** may further include an interface (not shown), such as a hot stab, so that the ROV **415** may operate the actuator **143**. The actuator **143** may also be in communication with the stab plate for operation by the pod **340**. The latch **142** may include outer members and a crossbar **145** (FIG. **5**C) connected to each of the outer members by a shearable fastener **144**. The actuator **143** may be dual function so that the latch may be locked in either of the positions by either the pod **340** or the ROV **415**.

The control pod **340** may be in electric, hydraulic, and/or optic communication with a control van **305** onboard a support vessel **400** (FIG. **4**A) via an umbilical **350** (FIG. **4**D). The pod **340** may include one or more control valves (not shown) in communication with the BOP stack **120** (via the stab plate) for operating the BOP stack. Each control valve may include an electric or hydraulic actuator in communication with the umbilical **350**. The umbilical **350** may include one or more hydraulic or electric control conduit/cables for each actuator. The accumulators **145** may store pressurized hydraulic fluid for operating the BOP stack **120**. Additionally, the accumulators **145** may be used for operating one or more of the other components of the PCA **100**. The accumulators **145** may be charged via a conduit of the umbilical **350** or by the ROV **415**.

The umbilical **350** may further include hydraulic, electric, and/or optic control conduit/cables for operating valves of the manifold **135**, the actuators **115***a*, **143**, tree valves **57***p,u,l* and the various functions of the workstring modules **500**, **600** (discussed below). The stab plate may further include an output for the workstring modules **500**, **600** and an output for the tree **50**. Each output may include an ROV operable connector for receiving a respective jumper **353**, **551**, **651** (aka flying lead) (FIGS. **4**E, **5**A, and **6**). The ROV **415** may connect the tree jumper **353** to a control panel (not shown) of the tree **50** and the workstring jumpers **551**, **651** to a control relay of one of the workstring modules **500**, **600**. The umbilical **350** may further include one or more layers of armor (not shown) made from a high strength metal or alloy, such as steel, for supporting the umbilical's own weight and weight of the control pod **340**.

The control pod **340** may further include a microprocessor based controller, a modem, a transceiver, and a power supply. The power supply may receive an electric power signal from a power cable of the umbilical **350** and convert the power signal to usable voltage for powering the pod components as well as any of the PCA components. The PCA **100** may further include one or more pressure sensors (not shown) in communication with the PCA bore at various locations. The workstring modules **500**, **600** may also include one or more pressure sensors in communication with a respective bore thereof at various locations. The pressure sensors may be in data communication with the pod controller. The modem and transceiver may be used to communicate with the control van **305** via the umbilical **350**. The power cable may be used for data communication or the umbilical **350** may further include a separate data cable (electric or optic). The control van **305** may include a control panel (not shown) so that the various functions of the PCA **100**, the tree **50**, and the workstring modules **500**, **600** may be operated by an operator on the vessel **400**.

The control pod **340** may also include a dead-man's switch (not shown) for closing the BOP stack **120** in response to a loss of communication with the control van **305**. Alternatively, instead of having individual conduits/cables for controlling each function of the PCA **100**, tree **50**, and workstring modules **500**, **600**, the pod controller may receive multiplexed instruction signals from the van operator via a single electric, hydraulic, or optic control conduit/cable of the umbilical **350** and then operate the various functions using individual conduits/cables extending from the control pod **340**.

The manifold **135** may include one or more actuated valves (not shown) and one or more couplings, such as dry break coupling **255***f*, for receiving a respective fluid conduit **355** (FIG. **4**F) from the vessel **400**. Actuators of the manifold valves and the couplings **255***f* may be in communication with the control pod **340** via the stab plate. Two fluid conduits **355** (only one shown) may extend from a vessel **400** to the manifold **135** for fluid circulation. A first one of the manifold valves may be in fluid communication with a first one of the couplings **255***f* and a fluid conduit extending to the port **110***p*. A second one of the manifold valves may be in fluid communication with a second one of the couplings (not shown) and another ROV operable connector for receiving a jumper **552**, **652** (FIGS. **5**A and **6**) providing fluid communication with one of the junction plates of the workstring modules **500**, **600**.

FIG. **3**A illustrates a passive dry-break connection **200**, according to another embodiment of the present invention. FIG. **3**B illustrates couplings **205***m,f* of the connection **200** disconnected. The connection **200** may include a male coupling **205***m* and a female coupling **205***f*.

The male coupling **205***m* may include a housing **206**, a plug **207**, a face seal **208**, a cap **209**, and a biasing member, such as a spring **210**. A first end of the cap **209** may form a fitting and have a profile (not shown), such as a barb, thread, or flange, for connection to other parts of the fluid conduit **355** (discussed below). A second end of the cap **209** may connect to the housing **206**, such as by a threaded connection (not shown). The plug **207** may be disposed in the housing and longitudinally movable relative thereto between an open position (FIG. **3**A) and a closed position (FIG. **3**B). The housing **206** may have a seat portion **206***s* extending radially inward from a cylindrical portion thereof. The face seal **208** may be disposed in a recess formed in a second end of the plug **207** and may be connected to the plug, such as by bonding, press fit, or molding. The spring **210** may be disposed in the housing **206** between the cap **209** and a first end of the plug **207**. The spring **210** may bias the plug **207** toward the seat **206***s* and the face seal **208** may engage a first sealing surface of the seat in the closed position. The plug **207** may have one or more flow passages **207***p* formed therethrough. The passages **207***p* may be spaced around the plug **207** near an outer surface thereof. Alternatively, the passages **207***p* may each include a radial component so that the passages diverge from a center of the plug **207** at a first end to an outer surface of the plug at a second end to that flow bypasses the spring **210**.

The female coupling **205***f* may include a housing **216**, a plug **217**, a face seal **218**, a tappet **219**, a biasing member, such as a spring **220**, and a latch, such as a collet **225**. A second end of the tappet **219** may form a fitting and have a profile (not shown), such as a barb, thread, or flange, for connection to other parts of the fluid conduit **355**. The tappet **219** may be connected to the housing **216**, such as by fasteners or a threaded connection (not shown). The plug **217** may be disposed in the housing **216** and longitudinally movable relative thereto between an open position (FIG. **3**A) and a closed position (FIG. **3**B). The tappet **219** may have one or more ports **219***p* formed through a wall thereof. The plug **217** may have a bore formed therethrough and the tappet may extend through the bore. A first end of the tappet **219** may form a seat **219***s*. The face seal **218** may be disposed in a recess formed in a first end of the plug **217** and may be connected to the plug, such as by bonding, press fit, or molding. The spring **220** may be disposed in the housing **216** between the housing and a second end of the plug **217**. The spring **220** may bias the plug **217** toward the seat **219***s* and the face seal **218** may engage a second sealing surface of the seat in the closed position. The collet **225** may be disposed around the housing **216** and connected thereto, such as by a threaded connection and/or fasteners. The collet **225** may include a base and a plurality of split fingers **225***f* extending longitudinally from the base. The fingers **225***f* may have lugs formed at an end distal from the base.

To form the connection, the male **205***m* and female **205***f* couplings may be aligned and the couplings pushed together. As the couplings **205***m,f* are pushed, the tappet seat **219***s* may engage the male face seal **208** and push the male plug **207** away from the male housing seat **206***s* and against the male spring **210**. Simultaneously, a second surface of the male housing seat **206***s* may engage the female face seal **218** and push the female plug **217** away from the tappet seat **219***s* and against the female spring **220**. The male and female springs **210**, **220** may each have a corresponding stiffness such that the plugs **207**, **217** each move a corresponding amount. Also as the couplings **205***m,f* are pushed together, a first chamfered surface of the lugs may engage a chamfered surface at a second end of the cap **209**, thereby pushing the fingers **225***f* radially outward. The couplings **205***m,f* may be pushed together until a second chamfered surface of the collet lugs engage another chamfered surface of the cap **209** at a shoulder of the cap, thereby allowing stiffness of the fingers **225***f* to return the fingers to their natural position. Engagement of a second end of the male housing **206** with a shoulder of the female housing **216** at or shortly after the fingers **225***f* return may serve as a rigid stop. The stiffness of the fingers **225***f* may resist separation due to pressure force and/or weight of the fluid conduit **355** but may allow separation of the couplings **205***m,f* in response to substantial tension exerted on the connection due to drift off or drive off of the vessel **400** in an emergency (discussed below).

FIG. **3**C illustrates an actuated dry break connection **250**, according to another embodiment of the present invention. The connection **250** may include the male coupling **205***m* and a female coupling **255***f*. The female coupling **255***f* may be similar to the female coupling **205***f* except that an actuator **260** has been added and the collet may be connected to the female housing by a shearable connection, such as one or more shear screws **280**. The actuator **260** may include a housing **261**, a piston **262**, a nut **263**, and a biasing member, such as a spring **264**. The housing **261** may be connected to the nut **263**, such as by a threaded connection (not shown). The nut **263** may be connected to the female housing, such as by a threaded connection (not shown). The piston **262** may be longitudinally movable relative to the housing between a locked position (shown) and an unlocked position (not shown). The spring **264** may be disposed between the nut **263** and the piston **262** and may bias the piston toward the locked position. A shoulder of the piston **262** may engage a shoulder of the female housing in the locked position. A sleeve portion of the piston **262** may engage an outer surface of the collet fingers in the locked position, thereby preventing disengagement of the fingers from the cap. A piston chamber may be formed between the housing **261** and the piston **262**. A port **261***p* may be formed through the housing **261** and a hydraulic conduit (not shown) may connect to the port. The conduit may provide hydraulic communication between the port **261***p* and the stab plate for operation of the actuator by the control pod **340**. Injection of hydraulic fluid into the chamber via the port **261***p* may move the piston **262** toward the nut **263** and against the spring **264** until the sleeve portion is clear of the fingers, thereby unlocking the fingers. Relief of the hydraulic fluid from the chamber via the port **261***p* may allow the spring **264** to return the piston **262** to the locked position. The stab plate/pod hydraulic circuit (not shown) may be dual-function so that the actuator **260** may be locked in either of the positions.

FIG. **4**A illustrates deployment of the PCA **100** to the subsea production tree **50**, according to another embodiment of the present invention. FIG. **4**B illustrates connection of the PCA **100** to the tree **50**. The support vessel **400** may be deployed to a location of the subsea tree **50**. The support vessel **400** may be a light or medium intervention vessel and include a dynamic positioning system to maintain position of the vessel **400** on the waterline **1***w* over the tree **50** and a heave compensator (not shown) to account for vessel heave due to wave action of the sea **1**. Alternatively, the vessel **400** may be a MODU. The vessel **400** may further include a tower **411** located over a moonpool **405** and a winch **413**. The winch **413** may include a drum having wire rope **450** wrapped therearound and a motor for winding and unwinding the wire rope, thereby raising and lowering a distal end of the wire rope relative to the tower. Alternatively, a crane (not shown) may be used instead of the winch and tower. The vessel **400** may further include a wireline winch **404**.

The ROV **415** may be deployed into the sea **1** from the vessel **400**. The ROV **415** may be an unmanned, self-propelled submarine that includes a video camera, an articulating arm, a thruster, and other instruments for performing a variety of tasks. The ROV **415** may further include a chassis made from a light metal or alloy, such as aluminum, and a float made from a buoyant material, such as syntactic foam, located at a top of the chassis. The ROV **415** may be controlled and supplied with power from vessel **400**. The ROV **415** may be connected to support vessel **400** by an umbilical **416**. The umbilical **416** may provide electrical (power), hydraulic, and/or data communication between the ROV **415** and the support vessel **400**. An operator on the support vessel **400** may control the movement and operations of ROV **415**. The umbilical **416** may be wound or unwound from drum **417**.

The ROV **415** may be deployed to the tree **50**. The ROV **415** may transmit video to the ROV operator for inspection of the tree **50**. The ROV **415** may remove the external cap **55** from the tree **50** and carry the cap to the vessel **400**. Alternatively, the winch **413** may be used to transport the external cap **55** to the waterline **1***w*. The ROV **115** may then inspect an internal profile of the tree **50**. The wire rope **460***d* may then be used to lower the PCA **100** to the tree **50** through the moonpool **405** of the vessel **400**. The ROV **415** may guide landing of the PCA **100** on the tree **50**. The ROV **415** may then operate the adapter connector **105***d* to fasten the PCA **100** to the tree **50**.

FIGS. **4**C and **4**D illustrate deployment of the control pod **340** to the PCA **100** using the umbilical **350**. FIG. **4**E illustrates connection of the control pod **340** to the PCA **100**. The vessel **400** may further include a launch and recovery system (LARS) **300** for deployment of the control pod **340** and the umbilical **350**. The LARS **300** may include a frame, an umbilical winch **310**, a boom **315**, a boom hoist **320**, a load winch **325**, and a hydraulic power unit (HPU, not shown). The LARS **300** may be the A-frame type (shown) or the crane type (not shown). For the A-frame type LARS **300**, the boom **315** may be an A-frame pivoted to the frame and the boom hoist **320** may include a pair of piston and cylinder assemblies (PCAs), each PCA pivoted to each beam of the boom and a respective column of the frame. The HPU may include a hydraulic fluid reservoir, a hydraulic pump, and one or more control valves for selectively providing fluid communication between the reservoir, the pump, and the PCAs **320**. The hydraulic pump may be driven by an electric motor.

The umbilical **350** may include an upper portion **351** and a lower portion **352** fastened together by a shearable connection **341**. Each winch **310**, **325** may include a drum having the respective umbilical upper portion **351** or load line **326** wrapped therearound and a motor for rotating the drum to wind and unwind the umbilical upper portion or load line **326**. The load line **326** may be wire rope. Each winch motor may be electric or hydraulic. An umbilical sheave and a load sheave may each hang from the A-frame **315**. The umbilical upper portion **351** may extend through the umbilical sheave and an end of the umbilical upper portion may be fastened to the shearable connection **341**. The frame may have a platform for the control pod **340** to rest. The umbilical lower portion **352** may be coiled and have a first end fastened to the shearable connection **341** and a second end fastened to the control pod **340**. The load line **351** may extend through the load sheave and have an end fastened to the lifting lugs of the control pod, such as via a sling. Pivoting of the A-frame boom **315** relative to the platform by the PCAs **320** may lift the control pod **340** from the platform, over a rail of the vessel **400**, and to a position over the waterline **1***w*. The load winch **325** may then be operated to lower the control pod **340** into the sea **1**.

A length of the umbilical lower portion **352** may be sufficient to provide slack to account for vessel heave. A length of the umbilical lower portion **352** may also be sufficient so that the shearable connection **341** is at or slightly above a depth of a top of the workstring modules **500**,**600** (FIGS. **5** and **6**). A length of the load line **326** may correspond to the length of the umbilical lower portion **352**. As the load winch **325** lowers the control pod **340**, the umbilical lower portion **352** may uncoil and be deployed into the sea **1** until the shearable connection **341** is reached. Once the shearable connection **341** is reached, a clump weight **361** may be fastened to a lower end of the umbilical upper portion **351**. The control pod **340** may continue to be lowered using the load winch **325** until the shearable connection **341** and clump weight **361** are deployed from the LARS platform to over the waterline **1***w*. The umbilical winch **351** may then be operated to support the control pod **340** using the umbilical **350** and the load line **326** slacked. The load line **326** and sling may be disconnected from the control pod **340** by the ROV **415**. Alternatively, the load line **326** may be wireline and the sling may have an actuator in communication with the wireline so that the van operator may release the sling. The control pod **340** may then be lowered to a landing depth (clump weight **361** and shearable connection **341** at or above top of workstring module **500**, **600**) using the umbilical winch **310**.

The PCA **100** may be deployed with the latch **142** locked in the disengaged position. Alternatively, the ROV **415** may operate the actuator **143** to disengage the latch after the PCA **100** has landed. As the pod **340** is being lowered to the landing depth, the ROV **415** may grasp the control pod and assist in landing the control pod **340** in the receptacle **140**. Once landed, the ROV **415** may engage the latch **142** with the pod **340**. The ROV **415** may then connect the jumper **353** to the tree control panel. The operator in the control van **305** may then close then close the tree valves **57***u,l,p* and the SSV via the umbilical **350**.

FIG. **4**F illustrates deployment and connection of a fluid conduit **355** to the tree. An upper portion of each fluid conduit **355** may be coiled tubing **356**. The vessel **400** may further include a coiled tubing unit (CTU, not shown) for each fluid conduit **355**. Each CTU may include a drum having the coiled tubing **356** wrapped therearound, a gooseneck, and an injector head for driving the coiled tubing **356**, controls, and an HPU. Alternatively, each CTU may be electrically powered. A lower portion of each fluid conduit **355** may include a hose **357**. The hose **357** may be made from a flexible polymer material, such as a thermoplastic or elastomer or may be a metal or alloy bellows. The hose **357** may or may not be reinforced, such as by metal or alloy cords. An upper end of the hose **357** may be connected to the coiled tubing **356** by the passive dry beak connection **200** and a lower end of the hose **357** may have the male coupling **205***m* (of the actuated connection **250**) connected thereto. The hose **357** may include two or more sections (only one section shown), each section fastened together, such as by a flanged or threaded connection. During deployment of the fluid conduit **355**, a clump weight **360** may be fastened to the lower end of the coiled tubing **356**.

The lower portion **357** of the fluid conduit **355** may be assembled on the vessel **400** and deployed into the sea **1** using the CTU. The coiled tubing **356** may be deployed until the clump weight **360** and passive dry break connection **200** are at or slightly above a depth of a top of the workstring modules **500**,**600**. The ROV **415** may then grasp the male coupling **205***m* of the actuated connection **250** and guide the coupling to the manifold **135**. A length of the hose **357** may be sufficient to provide slack in the fluid coupling **355** to account for vessel heave. The van operator may operate the actuator **260** to the unlocked position. The ROV **415** may then insert the male coupling **205***m* into the female coupling **255***f* and the van operator may lock the connection **250**. The operation may then be repeated for the second fluid conduit.

FIG. **5**A illustrates an intervention operation being conducted using a wireline module **500** connected to the PCA **100**, according to another embodiment of the present invention. For a more detailed view of the wireline module **500**, see FIG. 2B of U.S. patent application Ser. No. 13/018,871, filed Feb. 1, 2011 (Atty. Dock. No. WWCI/0011US), which is herein incorporated by reference in its entirety. The wireline module **500** may include an adapter, a fluid sub, an isolation valve, one or more stuffing boxes, a grease injector, a frame, a control relay, an interface, such as a junction plate, a grease reservoir, a grease pump, and a tool catcher. The adapter, fluid sub, isolation valve, stuffing boxes, grease injector, and tool catcher may each include a housing or body having a longitudinal bore therethrough and be connected, such as by flanges, such that a continuous bore is maintained therethrough.

The adapter may include a connector for mating with the connector profile **125***c*, thereby fastening the wireline module **500** to the PCA **100**. The connector may be dogs or a collet. The adapter may further include a seal face or sleeve and a seal. The adapter may further include an actuator, such as a piston and a cam, for operating the connector. The adapter may further include an ROV interface so that the ROV **415** may connect to the connector, such as by a hot stab, and operate the connector actuator. Alternatively, the adapter may have the connector profile instead of the connector and the tool housing may have the connector in communication with the control pod for operation by the van operator. The fluid sub may include a housing having a bore therethrough and a port in communication with the bore. The port may be in fluid communication with the junction plate via a conduit. The frame may be fastened to the adapter and the relay and interface may be fastened to the frame. The pump and reservoir may also be fastened to the frame.

The isolation valve may include a housing, a valve member disposed in the housing bore and operable between an open position and a closed position, and an actuator operable to move the valve member between the positions. The actuator may be electric or hydraulic and may be in communication with the control relay via a conduit. The actuator may fail to the closed position in the event of an emergency. The isolation valve may be further operable to cut the wireline **550** when closed or the wireline module **500** may further include a separate wireline cutter. The isolation valve may further operate as a check valve in the closed position: allowing fluid flow downward from the stuffing box toward the PCA **100** and preventing reverse fluid flow therethrough.

Each stuffing box may include a seal, a piston, and a spring disposed in the housing. A port may be formed through the housing in communication with the piston. The port may be connected to the control relay via a hydraulic conduit, not shown. When operated by hydraulic fluid, the piston may longitudinally compress the seal, thereby radially expanding the seal inward into engagement with the wireline **550**. The spring may bias the piston away from the seal and be set to balance hydrostatic pressure. Alternatively, an electric actuator may be used instead of the piston.

The grease injector may include a housing integral with the stuffing box housing and one or more seal tubes. Each seal tube may have an inner diameter slightly larger than an outer diameter of the wireline, thereby serving as a controlled gap seal. An inlet port and an outlet port may be formed through the grease injector/stuffing box housing. A grease conduit may connect an outlet of the grease pump with the inlet port and another grease conduit may connect the outlet port with the grease reservoir. Another grease conduit may connect an inlet of the pump to the reservoir. Alternatively, the outlet port may discharge into the sea **1**. The grease pump may be electrically or hydraulically driven via cable/conduit connected to the control relay and may be operable to pump grease from the grease reservoir into the inlet port and along the slight clearance formed between the seal tube and the wireline **550** to lubricate the wireline, reduce pressure load on the stuffing box seals, and increase service life of the stuffing box seals. The grease reservoir may be recharged by the ROV **415**.

The tool catcher may include a piston, a latch, such as a collet, a stop, a piston spring, and a latch spring disposed in a housing thereof. The collet may have an inner cam surface for engagement with a fishing neck of the PRT and/or BHA and the catcher housing may have an inner cam surface for operation of the collet. The latch spring may bias the collet toward a latched position. The collet may be movable from the latched position to an unlatched position either by engagement with a cam surface of the fishing neck and relative longitudinal movement of the fishing neck upward toward the stop or by operation of the piston. Once the cam surface of the fishing neck/BHA has passed the cam surface of the collet, the latch spring may return the collet to the latched position where the collet engages a shoulder of the fishing neck, thereby preventing longitudinal downward movement of the PRT/BHA relative to the catcher. The catcher housing may have a hydraulic port formed through a wall thereof in fluid communication with the piston. A hydraulic conduit (not shown) may connect the hydraulic port to the control relay. The piston may be biased away from engagement with the collet by the piston spring. When operated, the piston may engage the collet and move the collet upward along the housing cam surface to a latched position. Alternatively, an electric actuator may be used instead of the piston.

To prepare for intervention (or abandonment), the wireline **550** may be fed through the tower **411** and inserted through the wireline module **500** and connected to the PRT. The PRT may then be connected to the tool catcher. The wireline module **500** may then be deployed through the moonpool **405** using the wireline winch **404** and landed on the tool housing **125**. The ROV **415** may operate the adapter connector, thereby fastening the wireline module **500** to the PCA **100**. The ROV **415** may then connect jumper **551** to the control pod **340** and control relay and connect fluid conduit **552** to the manifold **135** and the junction box. The van operator may then engage one or both of the stuffing boxes with the wireline **550**. The van operator may then release the PRT from the tool catcher via the umbilical **350** and control relay. The PRT may be lowered to the upper crown plug **56***u* and operated to engage the upper crown plug by sending a signal through electrical conductors of the wireline **550**. The PRT and upper crown plug **56***u* may then be raised until the PRT reengages the tool catcher. The wireline module isolation valve may then be closed. The PRT and upper crown plug **56***u* may then be washed by injecting a hydrates inhibitor from the vessel **400**, through the fluid conduit **355**, the manifold, the conduit **551**, the junction plate, and into the wireline module port. The spent inhibitor may be returned to the vessel **400** through the port **110***p*, the manifold **135**, and the second fluid conduit (as discussed above, isolation valve **115** may allow downward flow when closed or the PCA **100** may include a bypass). Once washing is complete, the blind-shear preventer **120***b* may also be closed. The adapter connector may then be released by the ROV **415** and the wireline module **500** and upper crown plug **56***u* may be retrieved to the vessel **400**. The operation may then be repeated for the lower crown plug **56**.

The wireline module **500** and PRT may then be deployed again with a tree saver **590** (see FIG. 4F of the '871 application for more detail). The tree saver **590** may include a sleeve with a metal seal on its outer surface. The metal seal may be a depending lip that engages a tapered inner surface of the internal tree cap **54**. Alternatively, the tree saver metal seal may engage the tubing hanger **53** instead of the tree cap **54**. The sleeve may have a plurality of windows which allow fasteners, such as dogs, to extend and retract. The dogs may be pushed outward by an actuator, such as a central cam. The cam may have a profile on its upper end. The cam may move between a lower locked position and an upper position freeing dogs to retract. A retainer may secure to the upper end of body to retain the cam. The tree saver **590** may further include one or more seals. The seals may each be made from a polymer, such as an elastomer. The sleeve may have a length sufficient to extend past the production passage and the lower seal may engage an inner surface of the tubing hanger **53**, thereby isolating the production passage from any harmful fluids used during the intervention operation, such as cement or fracing fluid. Alternatively, the sleeve may extend into the production tubing **10***p* and the lower seal may engage an inner surface of the production tubing. The sleeve may also extend upward to the tree adapter **105** and the upper seal may engage an inner surface of the adapter sleeve **105***s*. Alternatively, the sleeve portion extending from the dogs to the tree connector and the upper seal may be omitted.

Once the tree saver **590** has been installed, the wireline module **500** may be redeployed and landed on the PCA **100** with the BHA **575** for the intervention (or abandonment) operation. The BHA **575** may then be lowered into the wellbore.

FIG. **5**B illustrates emergency disconnection from the PCA **100** in response to a minor emergency, according to another embodiment of the present invention. A minor emergency may include a minor equipment failure on the vessel **400**, such as failure of the dynamic positioning system, general power failure of the vessel, or requirement to quickly depart from the wellsite, such as due to inclement weather. Assuming communication between the control van **305** and the control pod **340** is intact (i.e., the vessel **400** has at least emergency power). The BHA **575** may be retrieved into engagement with the tool catcher. The wireline isolation valve may be closed, thereby severing the wireline **550**. The PCA isolation valve and the blind ram BOP may then be closed. The disconnect actuator **260** may then be moved to the disengaged position and locked in the disengaged position. The receptacle actuator **143** may then move the latch **142** to the disengaged position and be locked in the disengaged position. As the vessel **400** drifts or drives off, tension may be exerted on the dry break connection **250** by the fluid conduit **355**, thereby pulling the male coupling **205***m* from the female coupling **255***f*, and tension may be exerted on the control pod **340** by the umbilical **350**, thereby lifting the control pod from the receptacle **140**. The vessel **400** may then be free to drift or drive off from the wellsite.

FIG. **5**C illustrates emergency disconnection from the PCA **100** in response to a major emergency, according to another embodiment of the present invention. A major emergency may include a major equipment failure on the vessel **400** and/or incapacitation of the vessel crew, such as due to a fire and/or explosion on the vessel caused by a blowout from the wellbore **10** or severe storm. The dead-man switch may detect loss of communication with the van **305**. The dead-man switch may then close the BOPs **120***b,w*, thereby cutting the wireline **550**. One of the BOPs **120***b,w* may also be configured to grab and hold the wireline **550** so that the BHA **575** does not drop to the bottom of the wellbore **10**. The wireline isolation valve may be closed, thereby again cutting the wireline **550**. As the vessel **400** drifts off, tension may be exerted on the passive dry break connection **200** by the fluid conduit **355**, thereby pulling the male coupling **205***m* from the female coupling **205***f*, and tension may be exerted on the control pod **340** by the umbilical **350**, thereby shearing the latch fastener **144**. If the passive connection **200** fails to disconnect, then the shear screw **280** may release the male coupling **205***m* and collet from the female coupling **255***f*.

If the latch fastener **144** fails to shear and/or the control pod **340** and umbilical lower portion **352** become entangled with the PCA **100** and/or wireline module **500**, then the shearable coupling **341** may disconnect the umbilical upper portion **351** from the control pod **340** and umbilical lower portion **352**. The vessel **400** may then be free to drift off from the wellsite. The clump weights **360**, **361** may each maintain tension in the respective coiled tubing **356** and umbilical upper portion **351** such that lateral spacing among the coiled tubing **356**, umbilical upper portion **351**, and wireline **550** remains constant, thereby ensuring no contact or entanglement between them. Having the landing depth of the clump weights **360**, **361** and adjacent respective dry break coupling **200** and shearable connection **341** at or above a depth of the top of the wireline module **500** ensures no entanglement of the respective coiled tubing **356** and umbilical upper portion **351** with the PCA **100** and/or wireline module.

Regarding the dry break connections **200**, **250**, the collet of the passive connection may have a stiffness greater or substantially greater than the actuated connection so that the when the actuated connection is unlocked, the actuated connection may require less or substantially less tension to release. The shear screw(s) **280** may require a greater or substantially greater tension than the passive collet to separate so that the passive connection **200** may separate before the actuated connection **250** (when locked). The tension to shear the shear screws **280** may be less or substantially less than a minimum tensile strength of the fluid conduit **355** (i.e., a tensile strength of the hose **357**).

Regarding the pod receptacle shearable fasteners **144** and the shearable connection **341**, the shearable connection **341** may release at a greater or substantially greater tension than required to release the shearable fasteners **144**. The tension required to release the shearable connection **341** may be less or substantially less than a tensile strength of the umbilical **350** and greater or substantially greater than a weight of the control pod **340**.

FIG. **6** illustrates an intervention operation being conducted using a coiled tubing module **600** connected to the PCA **100**, according to another embodiment of the present invention. For a more detailed view of the coiled tubing module **600**, see FIG. 2C of the '871 application. The coiled tubing module **600** may be deployed instead of the wireline module **500** to conduct the intervention or abandonment operation. The coiled tubing module **600** may include an adapter, a fluid sub, an isolation valve, a stripper, a subsea coiled tubing injector, a frame, a control relay, an interface, such as a junction plate, and a tool catcher. The adapter, fluid sub, isolation valve, stripper, and tool catcher may each include a housing or body having a longitudinal bore therethrough and be connected, such as by flanges, such that a continuous bore is maintained therethrough. The adapter may be similar to the wireline adapter. The frame may be fastened to the adapter and the relay and the interface may be fastened to the frame. The fluid sub may include a housing having a bore therethrough and a port in communication with the bore. The port may be in fluid communication with the junction plate via a conduit (not shown). The tool catcher may be similar to the wireline tool catcher.

The isolation valve may include a housing, a valve member disposed in the housing bore and operable between an open position and a closed position, and an actuator operable to move the valve member between the positions. The actuator may be electric or hydraulic and may be in communication with the control relay via a conduit (not shown). The actuator may fail to the closed position in the event of an emergency. The isolation valve may be further operable to cut coiled tubing **650** when closed or the coiled tubing module **600** may further include a separate coiled tubing cutter. The isolation valve may further operate as a check valve in the closed position: allowing fluid flow downward from the stripper toward the PCA **100** and preventing reverse fluid flow therethrough.

The stripper may include a seal and a piston disposed in the housing. A hydraulic packoff port and a hydraulic release port may be formed through the housing in fluid communication with a respective face of the piston. Each port may be connected to the control relay via a respective hydraulic conduit. When operated by pressurized hydraulic fluid via the pack-off port, the piston may longitudinally compress the seal, thereby radially expanding the seal inward into engagement with the coiled tubing. The seal may be released by application of pressurized hydraulic fluid via the release port. Alternatively, an electric actuator may be used instead of the piston. Alternatively, the stripper may include a spring instead of the release port.

The injector may include a traction assembly to engage the coiled tubing **650** and drive the coiled tubing into or out of the wellbore **10**. The traction assembly may include opposing chain loops guided by bearing assemblies. Gripping members may be secured to individual links of the chain loops, so as to grip the coiled tubing. The gripping members and the chain loops may thus move together longitudinally at the area of contact with the coiled tubing **650** to move the coiled tubing into or out of the wellbore **10**. A plurality of rollers may be secured to the links of the chain loops, and roll along support members. The support members may be moved laterally inwardly to urge the gripping members into engagement with the coiled tubing **650** with sufficient force to grip the coiled tubing. The rollers may allow for a large lateral load to be applied without inducing a significant longitudinal drag load.

The bearing assemblies and an injector gear case may both be sealed to retain lubricant and prevent intrusion of seawater. The bearing assemblies may be outboard bearing assemblies because the portion of the housing adjacent the sealed gear case may be open to seawater to accommodate the chain loops. The chain loops may be routed over sprockets or gears within the housing, rotating about the axis of the bearings assemblies, and the chain loops may thus be guided by the bearing assemblies. A hydraulic or electric drive motor may drive the chain loops. The drive motor may be in hydraulic/electric communication with the control relay via a conduit/cable. The gear case may house a plurality of gears which may be driven by the drive motor and which may drive the chain loops via a drive shaft sealably extending from the sealed gear case.

The injector may further include a lubricant reservoir. The reservoir may compensate pressure within the gear case, each outboard bearing assembly, and other components of the injector that are sealed and sensitive to pressure differentials, such as the rollers. The reservoir may include a housing structurally separate from and attached to an outer housing of the gear case. The reservoir housing may be divided into a compensator chamber and a lubricant chamber by a pressure compensator, such as a piston or diaphragm. The lubricant chamber maybe filled with a lubricant. A conduit may be used to fluidly connect and pass lubricant between the reservoir and the gear case, the bearing assemblies, the rollers, and other sealed components. The compensator chamber may be in fluid communication with the sea by a port formed through the reservoir housing. As the hydrostatic pressure surrounding the reservoir increases, such as when the injector is lowered into a subsea environment, the compensator may pressurize the lubricant, thereby equalizing or substantially equalizing the lubricant pressure and the hydrostatic seafloor pressure. The compensator may be biased so that the lubricant pressure is slightly greater than the seafloor pressure. Accordingly, the pressure differential that would otherwise exist between the seawater environment and the interior of the sealed components is reduced or eliminated.

The vessel **400** may further include an additional CTU (second or third) including injector head **475**, drum **420**, gooseneck, and HPU (not shown). The coiled tubing **650** may be inserted through the coiled tubing module **600** and connected to the BHA (not shown). The BHA may include one or more tools operable to perform an intervention or abandonment operation in the wellbore **10**. The BHA may then be connected to the tool catcher. The injector head **475** may be deployed over the moon pool **405** and the coiled tubing module may be lowered to the tree **50** using the vessel injector and the coiled tubing.

Once the coiled tubing adapter has landed onto the PCA **100**, the ROV **415** may operate the adapter connector, thereby fastening the coiled tubing module to the PCA **100**. The ROV **415** may then connect a jumper **651** to the control pod **340** and control relay and connect fluid conduit **652** to the manifold **135** and the junction box. Once fastened, the vessel injector **475** may feed the coiled tubing **650** toward the tree **50**, thereby creating slack in the coiled tubing **650**. The vessel **400** may then (or simultaneously) be moved a distance from the tree **50** ensuring safety of the vessel **400** should a blowout occur during the intervention operation. The slack may also serve to compensate for heave of the vessel.

The stripper may be engaged with the coiled tubing by the vessel operator and then the isolation valve, blind-shear BOP **120***b*, and SSV may be opened. The van operator may then release the BHA from the tool catcher via the umbilical **350** and control relay. The subsea drive motor may then be operated by the van operator, thereby advancing the BHA toward the tree **50**. The slack may be maintained through synchronization of the vessel injector with the subsea injector by communication with the surface controller. The coiled tubing **650** may continue be advanced (while maintaining the slack via synchronous operation of the vessel injector) into the wellbore **10** by the subsea injector until the BHA reaches a desired depth in the wellbore. The intervention or abandonment operation may then be conducted using the coiled tubing and the BHA. To facilitate the intervention or abandonment operation, fluid may be pumped through the coiled tubing **650** and the BHA and returned to the vessel **400** via the port **110***p*. Further, fluid may be pumped into the wellbore **10** before or after deployment of the BHA through the port **110***p* with the isolation valve **115** closed, thereby protecting the BOP stack **120** from the fluid.

The emergency disconnect system (EDS) may also facilitate deployment of the coiled tubing **650** with slack, especially for shallow wellheads (i.e., at a depth of less than or equal to one thousand feet) by reducing risk of entanglement of the umbilical **350** and/or fluid conduit(s) **355** with the coiled tubing module **600** or PCA **100** should an emergency occur. The EDS may function for the coiled tubing module **600** similarly as for the wireline module **500**, discussed above.

Once the intervention or abandonment operation has concluded, the BHA and workstring may be retrieved from the wellbore **10** by reversing the deployment and landing procedure, discussed above. The isolation valve **115** and SSV may then be closed by the vessel operator. The BHA may then be washed as discussed above for the upper crown plug **56***u*. The blind-shear preventer **120***b* may then be closed. If necessary, the vessel **400** may return to the position over the tree **50**. The slack may be removed from the coiled tubing by the vessel injector (after or simultaneously with vessel movement). The ROV **415** may disconnect the adapter connector and the workstring module **500**, **600** may be retrieved from the tree **50**. If an intervention operation was conducted, the tree saver **590** may be removed and the crown plugs **56***u,l* reinstalled using the wireline module **500** and PRT. The PCA **100** may then be retrieved and the well returned to production.

While the foregoing is directed to embodiments of the present invention, other and further embodiments of the invention may be devised without departing from the basic scope thereof, and the scope thereof is determined by the claims that follow.

The invention claimed is:

1. A method for riserless intervention of a subsea well, comprising:

lowering a pressure control assembly (PCA) from a vessel to a subsea production tree;

fastening the PCA to the tree;

lowering a control pod from the vessel to the PCA using an umbilical;

fastening the control pod to the PCA;

lowering an end of a fluid conduit from the vessel to the PCA;

fastening the fluid conduit to the PCA using a dry break connection;

lowering an intervention assembly to the PCA; and

fastening the intervention assembly to the PCA,

wherein:

the fluid conduit comprises an upper portion and a lower portion connected by a second dry break connection,

the umbilical comprises an upper portion and a lower portion connected by a shearable connection,

a clump weight is connected to each of the fluid conduit upper portion and the umbilical upper portion, and

the clump weights are each at a depth at or above a top of the intervention assembly.

2. The method of claim **1**, wherein:

the fluid conduit upper portion is a length of coiled tubing and the fluid conduit lower portion is a length of hose, and

the length of hose is fastened to the PCA.

3. The method of claim **2**, wherein:

the first dry break connection comprises an actuator operable to lock the connection, and

the second dry break connection is operable to release in response to tension exerted on the hose.

4. The method of claim **3**, wherein the actuator comprises a shearable fastener operable to release the fluid conduit in response to a predetermined tension exerted on the fluid conduit.

5. The method of claim **1**, wherein:

the control pod is fastened to the PCA by a pod receptacle comprising a latch and an actuator,

the latch comprises a shearable fastener operable to release the control pod in response to a predetermined tension exerted on the umbilical, and

the actuator is operable by either the control pod or a remotely operated vehicle (ROV).

6. A method for riserless intervention of a subsea well, comprising:

lowering a pressure control assembly (PCA) from a vessel to a subsea production tree;

fastening the PCA to the tree;

lowering a control pod from the vessel to the PCA using an umbilical;

fastening the control pod to the PCA;

lowering an end of a fluid conduit from the vessel to the PCA; and

fastening the fluid conduit to the PCA using a dry break connection,

wherein:

the control pod is fastened to the PCA by a pod receptacle comprising a latch and an actuator,

the latch comprises a shearable fastener operable to release the control pod in response to a predetermined tension exerted on the umbilical, and

the actuator is operable by either the control pod or a remotely operated vehicle (ROV).

7. The method of claim **6**, wherein:

the fluid conduit comprises a length of coiled tubing and a length of hose, and

the length of hose is fastened to the PCA.

8. The method of claim **7**, wherein a clump weight is connected to the coiled tubing at a depth above a top of the PCA.

9. The method of claim **7**, wherein the hose is connected to the coiled tubing by a second dry break connection.

10. The method of claim **9**, wherein:

the first dry break connection comprises an actuator operable to lock the connection, and

the second dry break connection is operable to release in response to tension exerted on the hose.

11. The method of claim **10**, wherein the actuator comprises a shearable fastener operable to release the fluid conduit in response to a predetermined tension exerted on the fluid conduit.

12. The method of claim **6**, wherein:

the umbilical comprises an upper portion and a lower portion,

the umbilical portions are connected by a shearable connection.

13. The method of claim **12**, wherein a clump weight is connected to the umbilical upper portion at a depth above a top of the PCA.

14. The method of claim **6**, further comprising:

lowering an intervention assembly to the PCA; and

fastening the intervention assembly to the PCA.

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