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(54) **CONVERTIBLE SLICKLINE STUFFING BOX**

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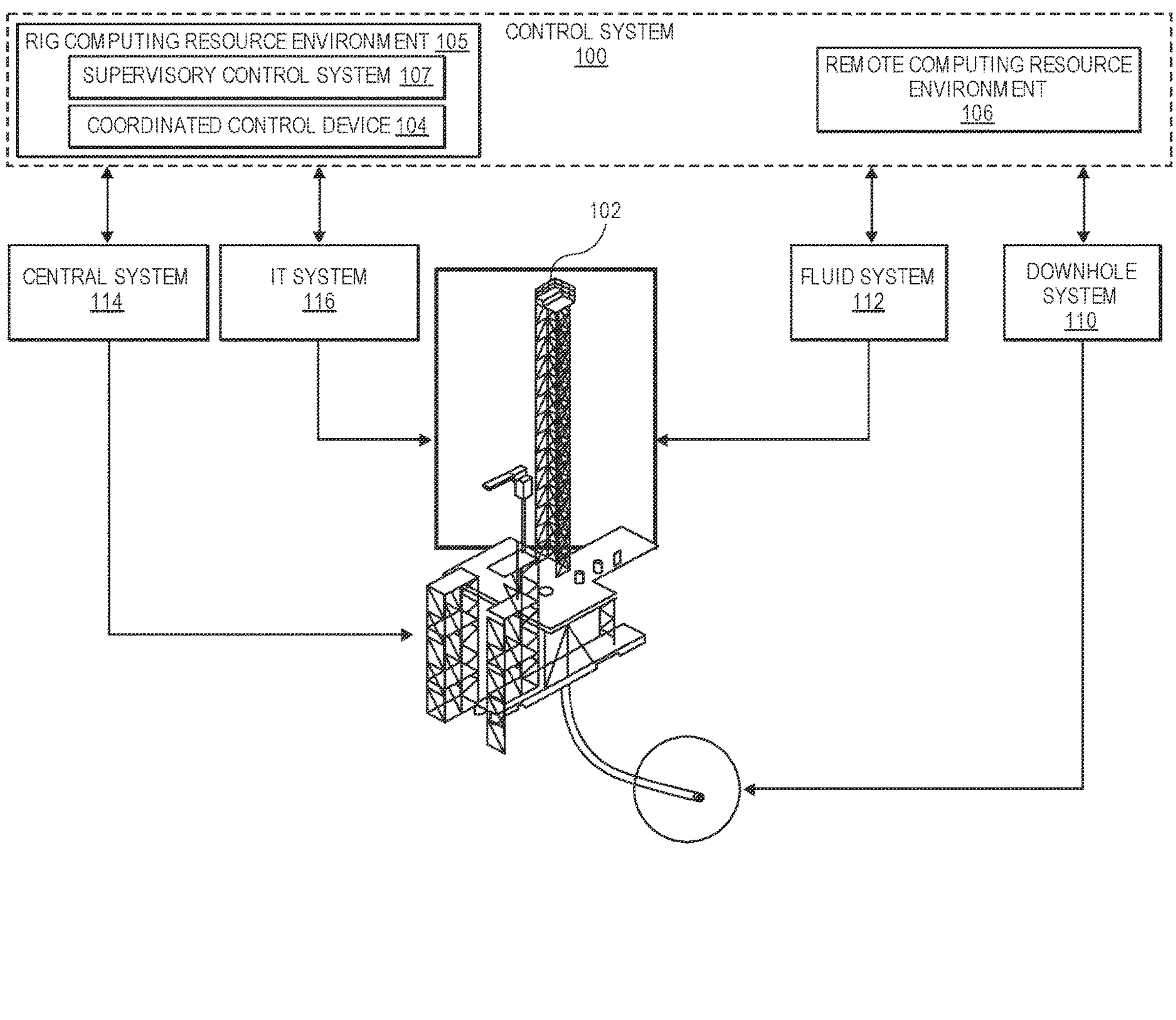
(57) **ABSTRACT**

A slickline stuffing box includes a piston configured to move in response to a force exerted thereon by a pressurized fluid. The slickline stuffing box also includes a packer element positioned above the piston. The packer element is configured to compress axially and expand radially, in response to movement of the piston, to seal around a slickline to contain a pressure within a wellbore during a slickline wellbore intervention. The slickline stuffing box also includes a valve configured to be positioned below the packer element in a first configuration of the slickline stuffing box and above the packer element in a second configuration of the slickline stuffing box. The valve is configured to contain the pressure within the wellbore in response to the slickline breaking and falling down and out of the slickline stuffing box.



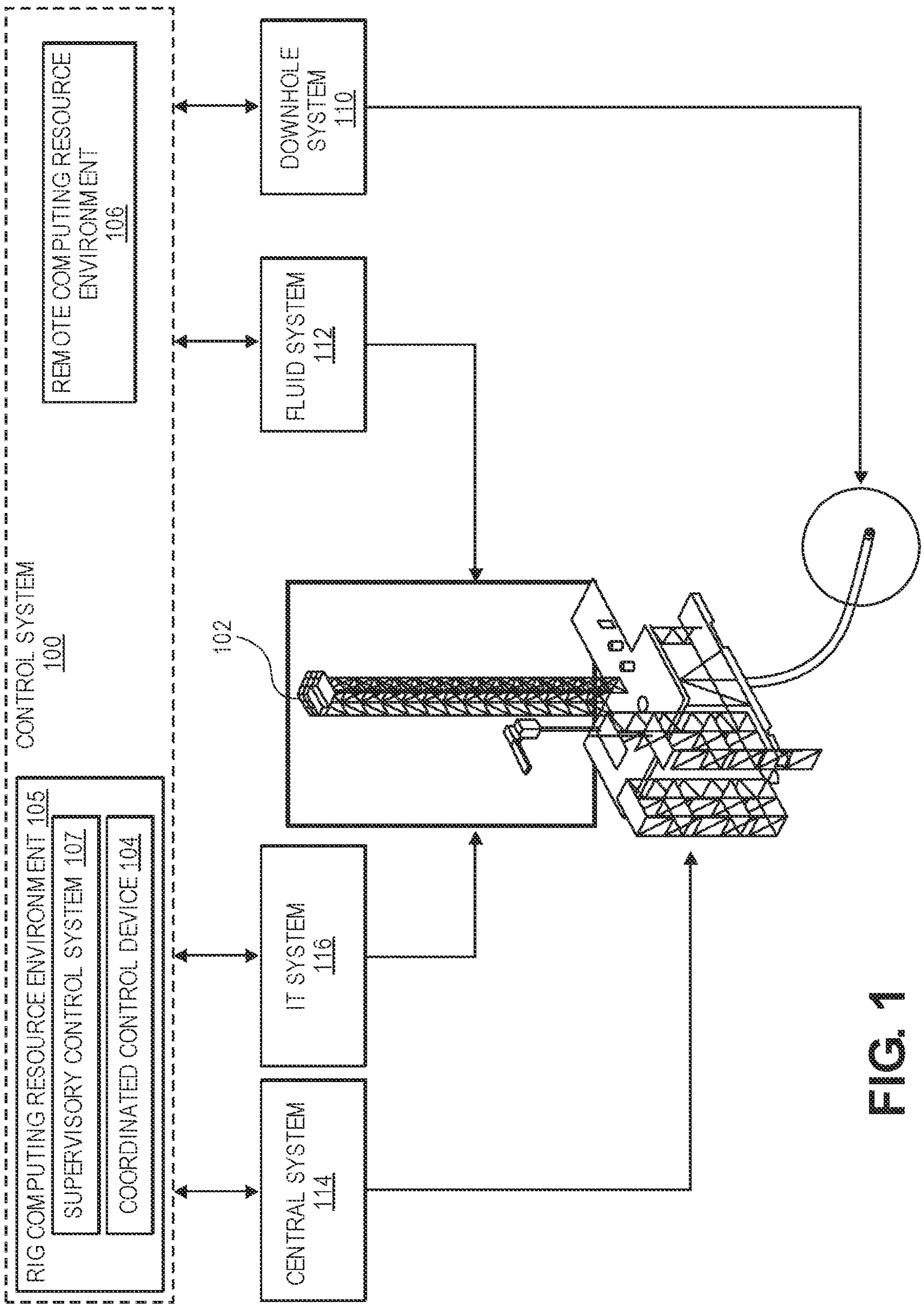
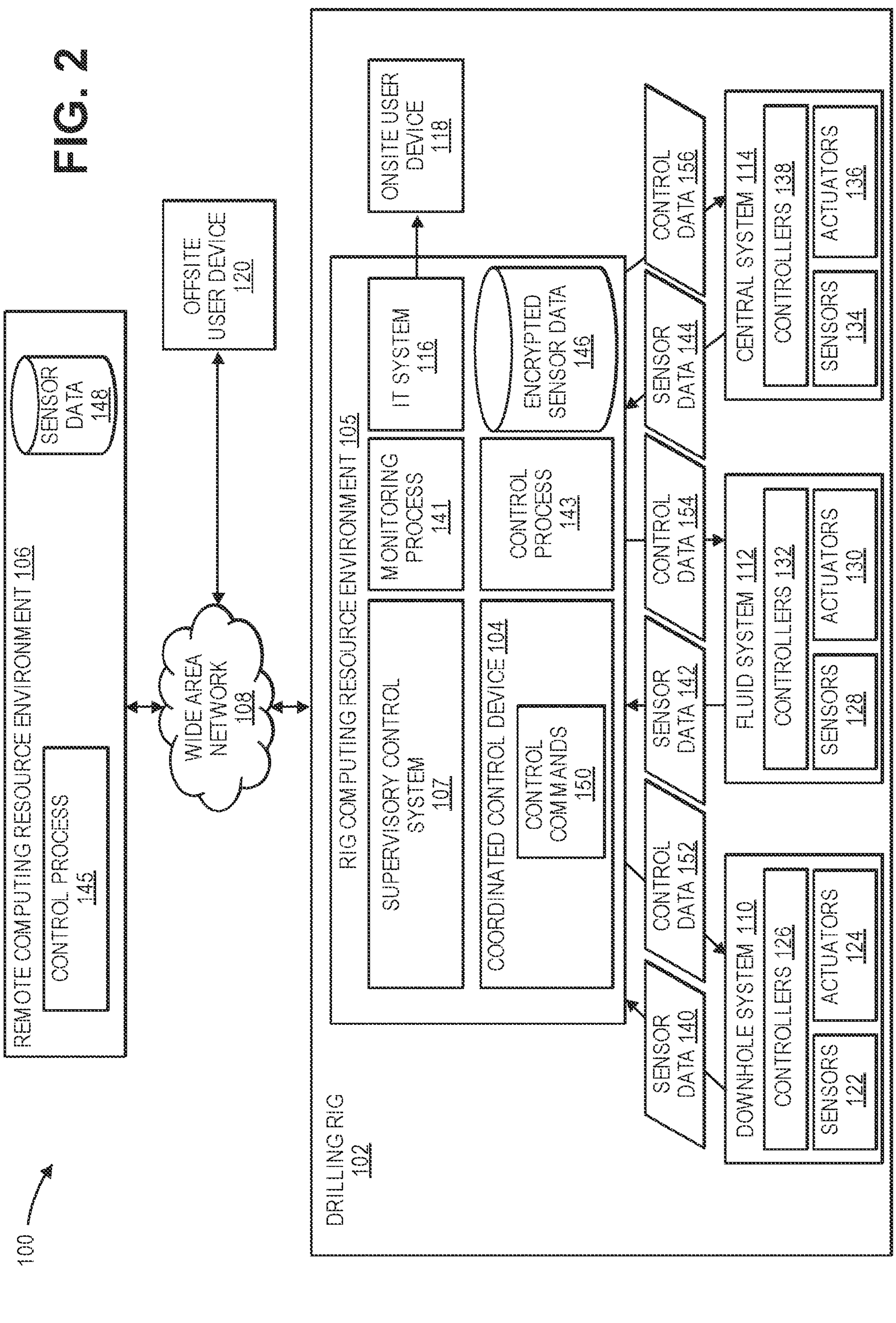

CONTROL SYSTEM
100
RIG COMPUTING RESOURCE ENVIRONMENT 105
SUPERVISORY CONTROL SYSTEM 107
COORDINATED CONTROL DEVICE 104
REMOTE COMPUTING RESOURCE ENVIRONMENT
106
CENTRAL SYSTEM
114
IT SYSTEM
116
FLUID SYSTEM
112
DOWNHOLE SYSTEM
110
102

FIG. 1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SENSOR DATA 148
WIDE AREA NETWORK 108
OFFSITE USER DEVICE 120
DRILLING RIG 102
RIG COMPUTING RESOURCE ENVIRONMENT 105
SUPERVISORY CONTROL SYSTEM 107
MONITORING PROCESS 141
IT SYSTEM 116
ONSITE USER DEVICE 118
COORDINATED CONTROL DEVICE 104
CONTROL COMMANDS 150
CONTROL PROCESS 143
ENCRYPTED SENSOR DATA 146
SENSOR DATA 140
CONTROL DATA 152
SENSOR DATA 142
CONTROL DATA 154
SENSOR DATA 144
CONTROL DATA 156
DOWNHOLE SYSTEM 110
CONTROLLERS 126
SENSORS 122
ACTUATORS 124
FLUID SYSTEM 112
CONTROLLERS 132
SENSORS 128
ACTUATORS 130
CENTRAL SYSTEM 114
CONTROLLERS 138
SENSORS 134
ACTUATORS 136

FIG. 2

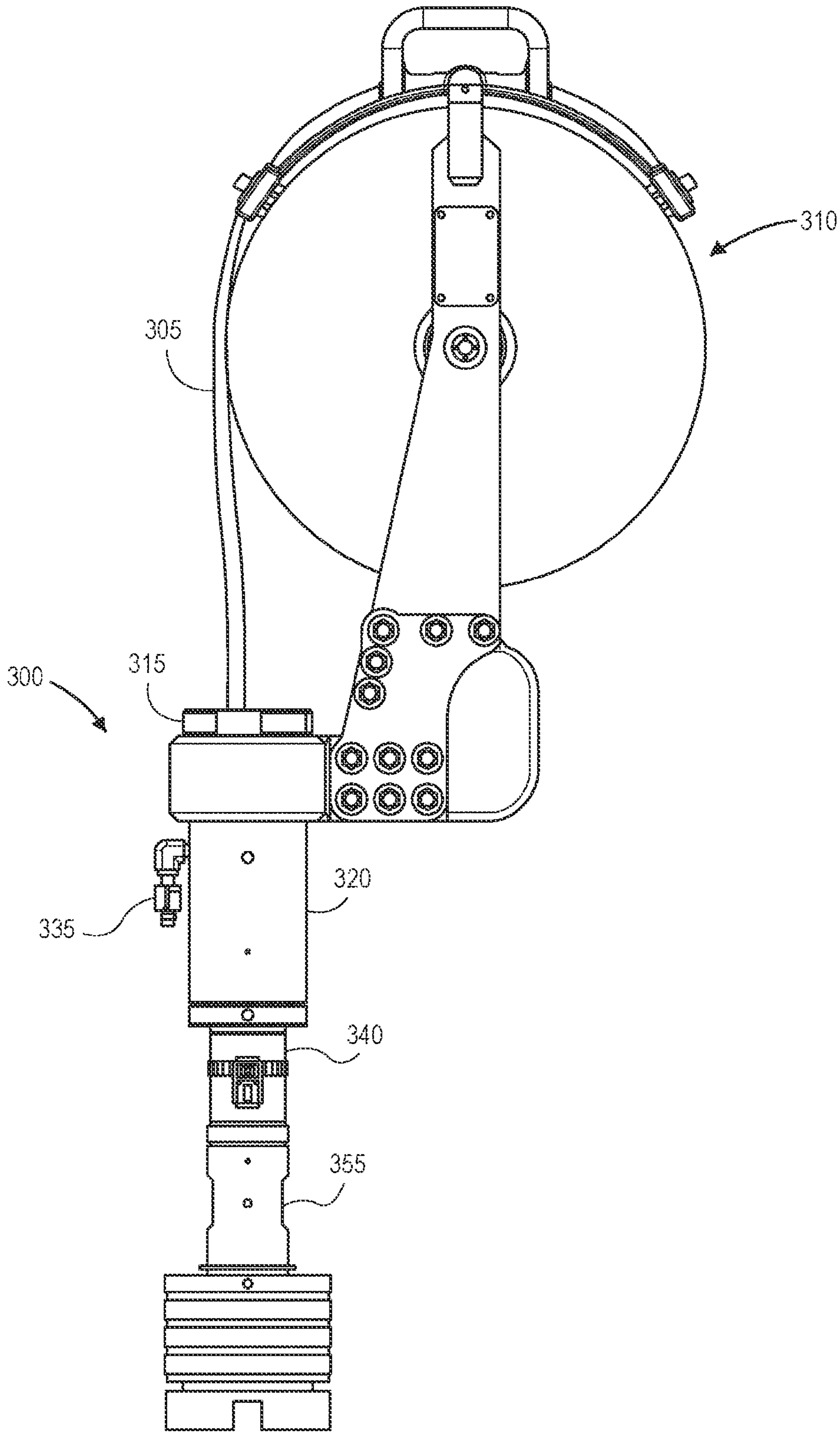
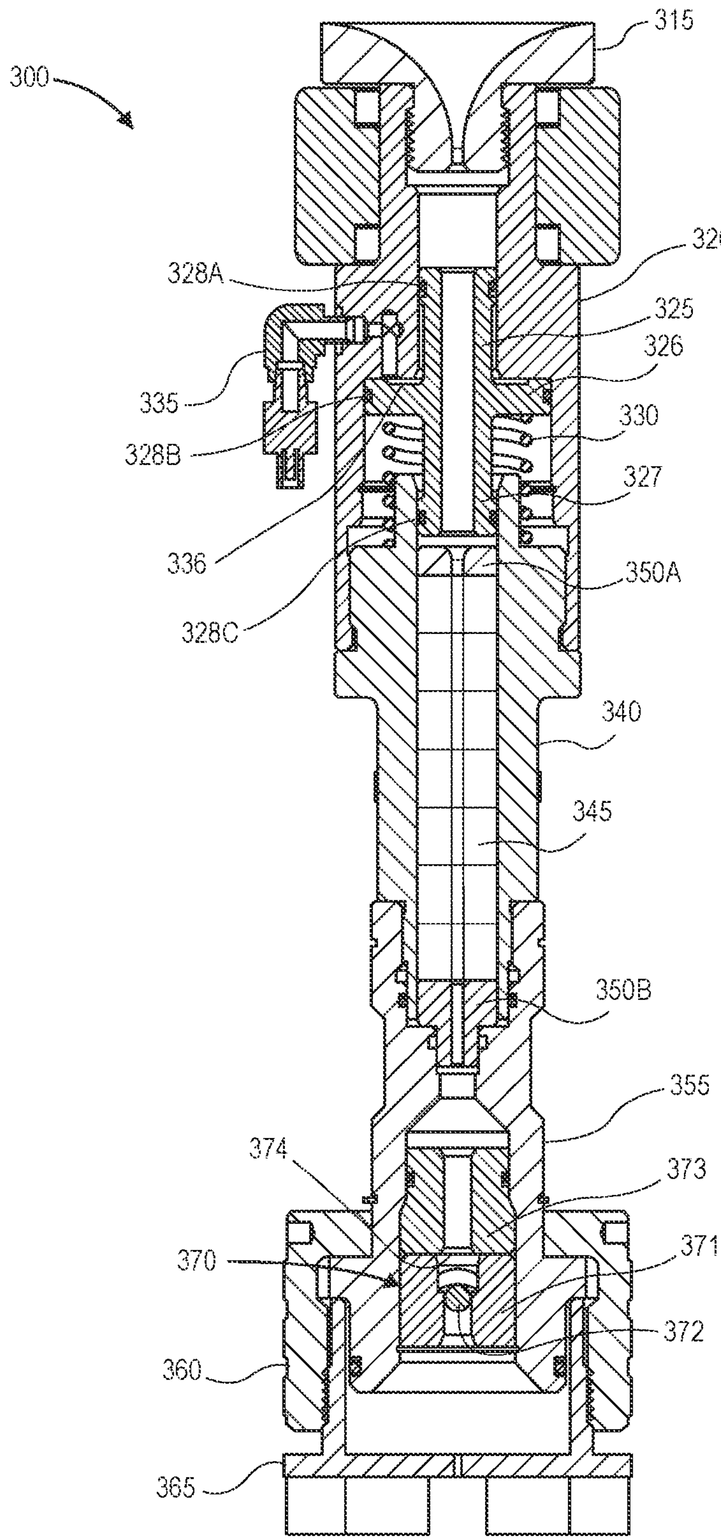


FIG. 3A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328A
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350A
328C
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FIG. 3B

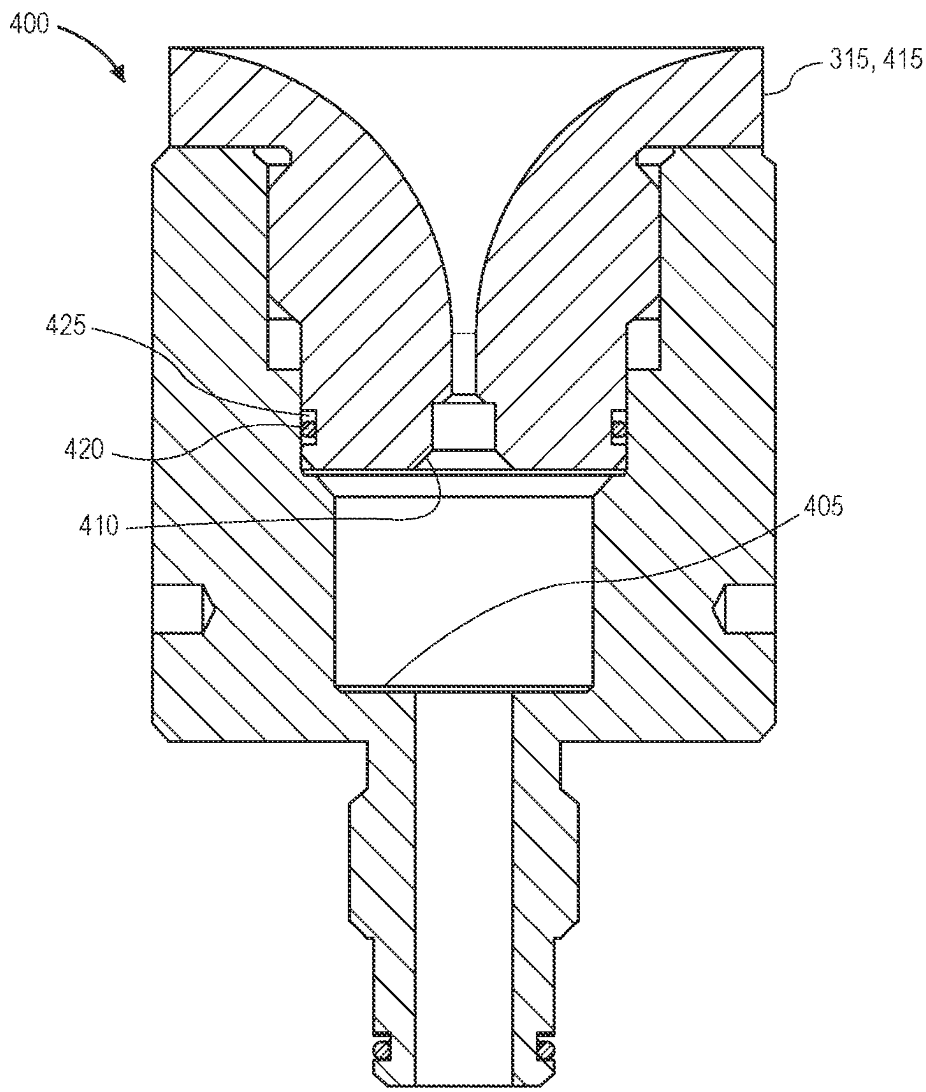

FIG. 4A

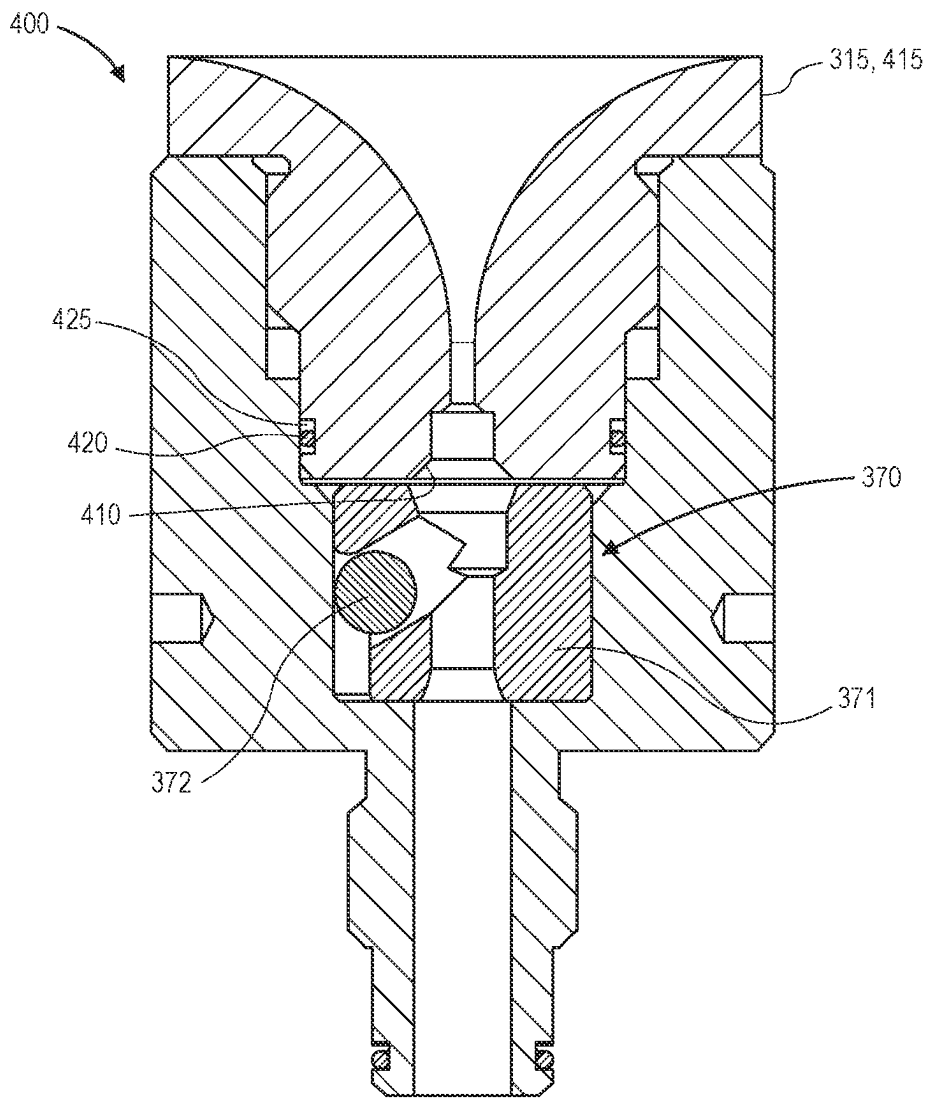

FIG. 4B

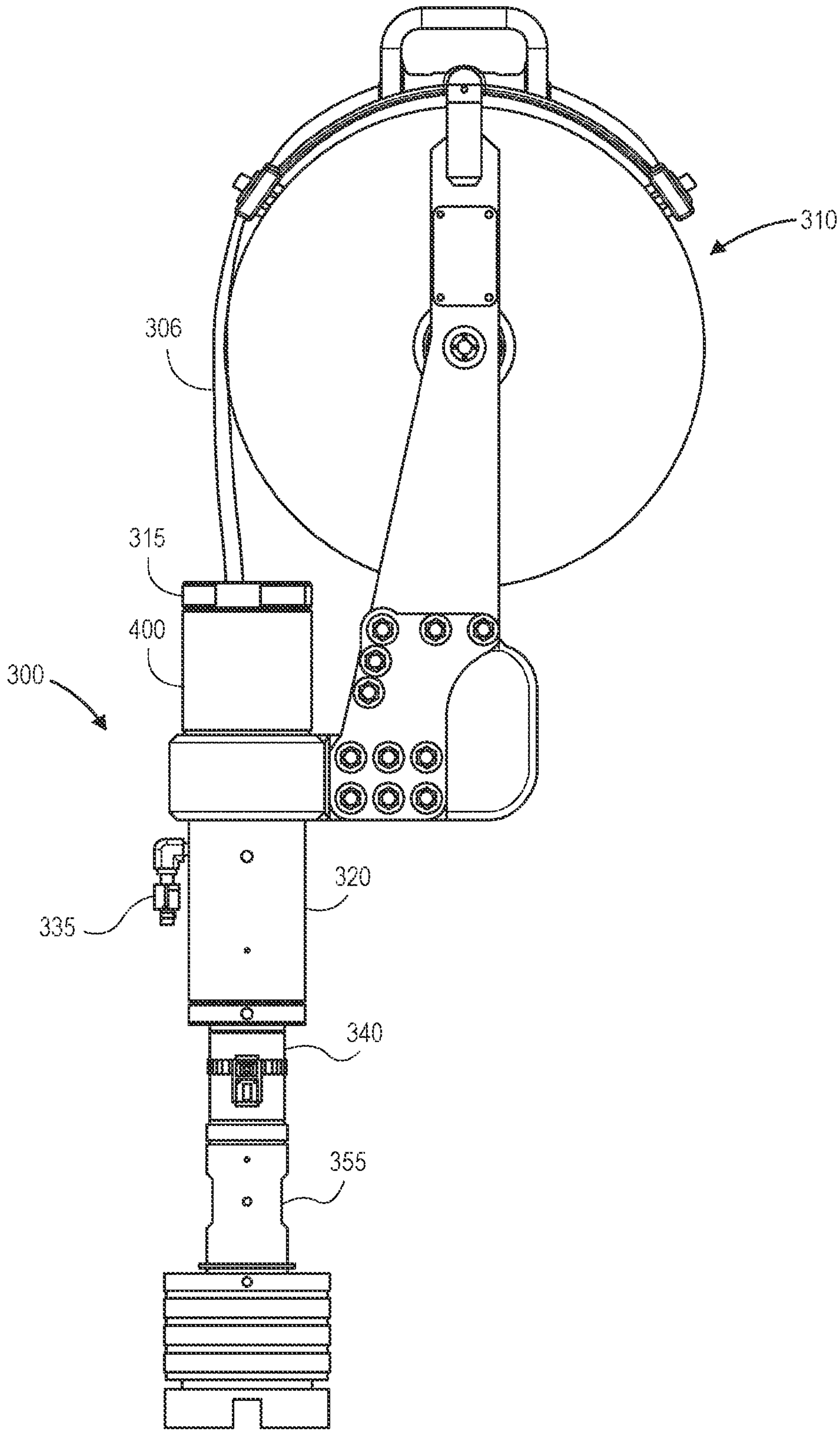

FIG. 5A

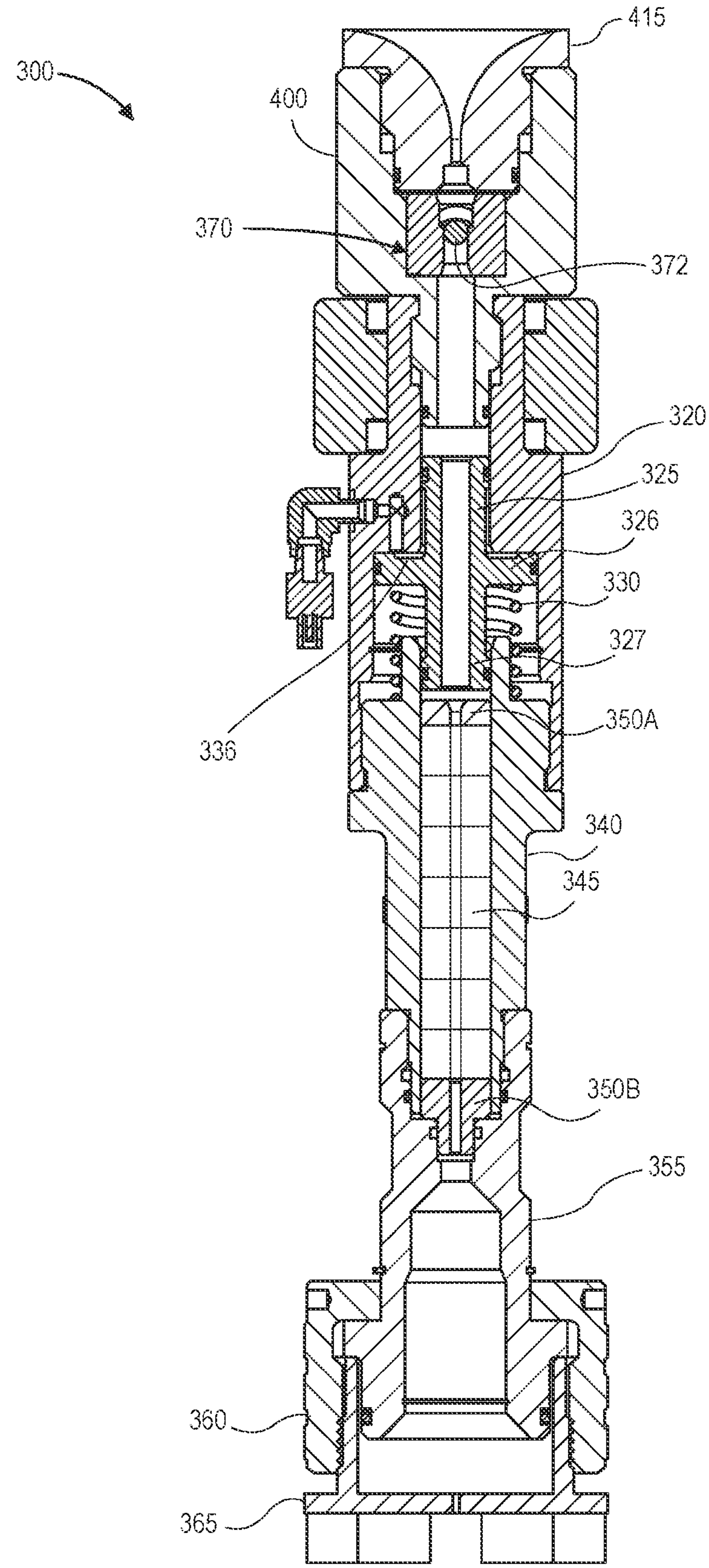
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FIG. 5B

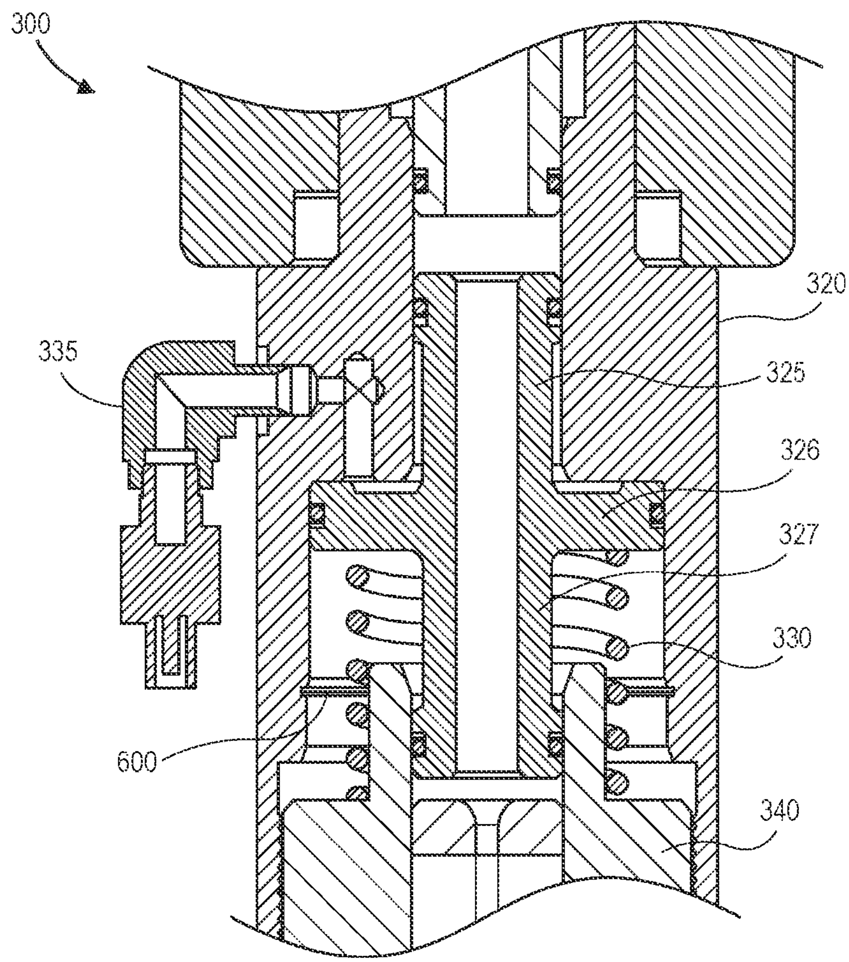

FIG. 6A

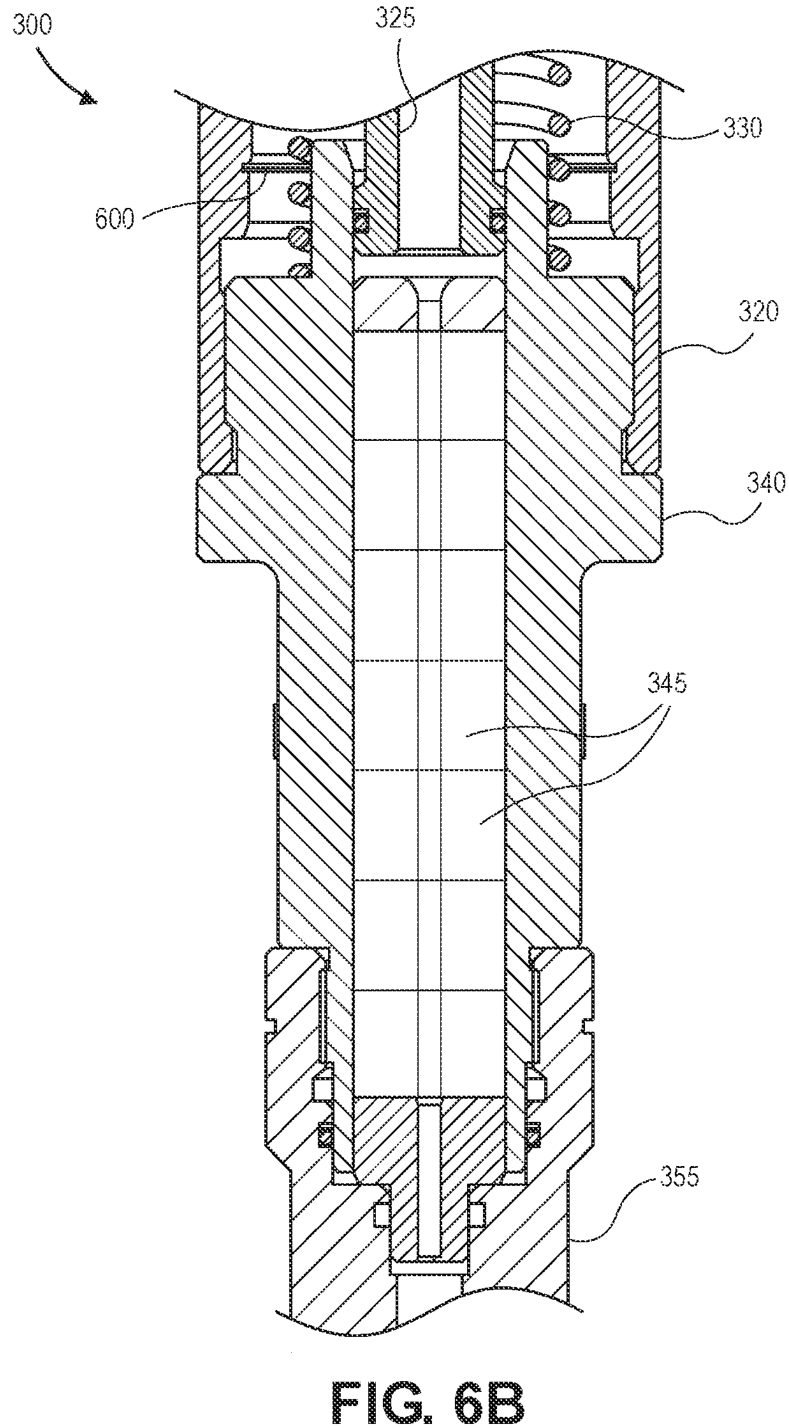

FIG. 6B

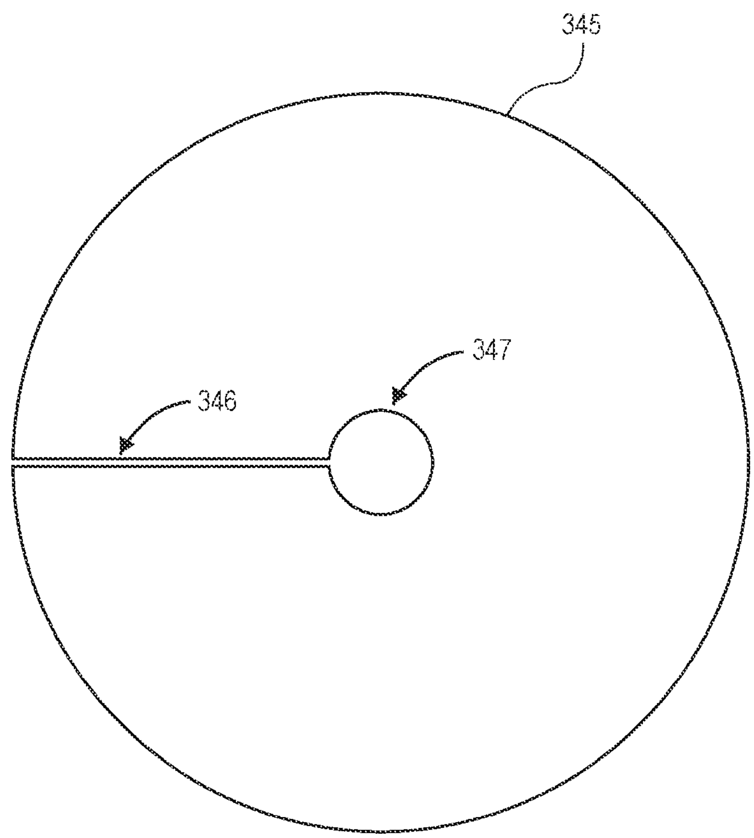

FIG. 6C

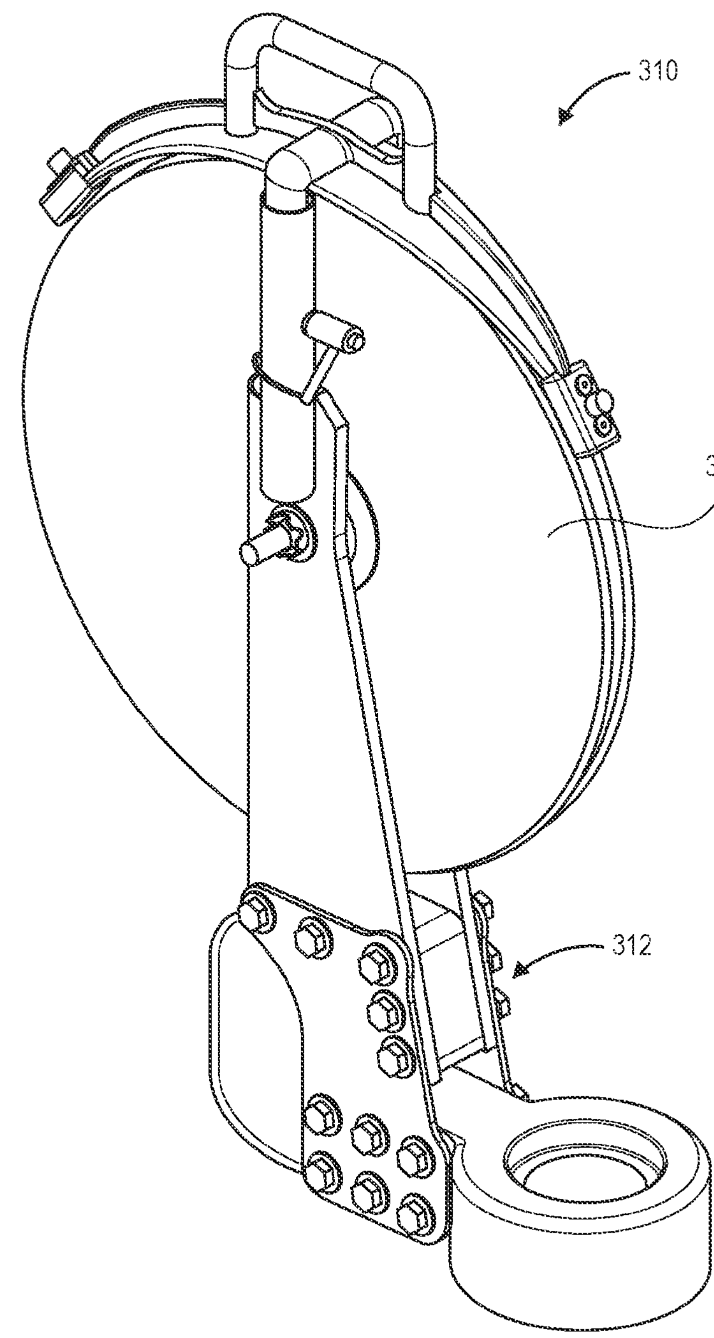

FIG. 7A

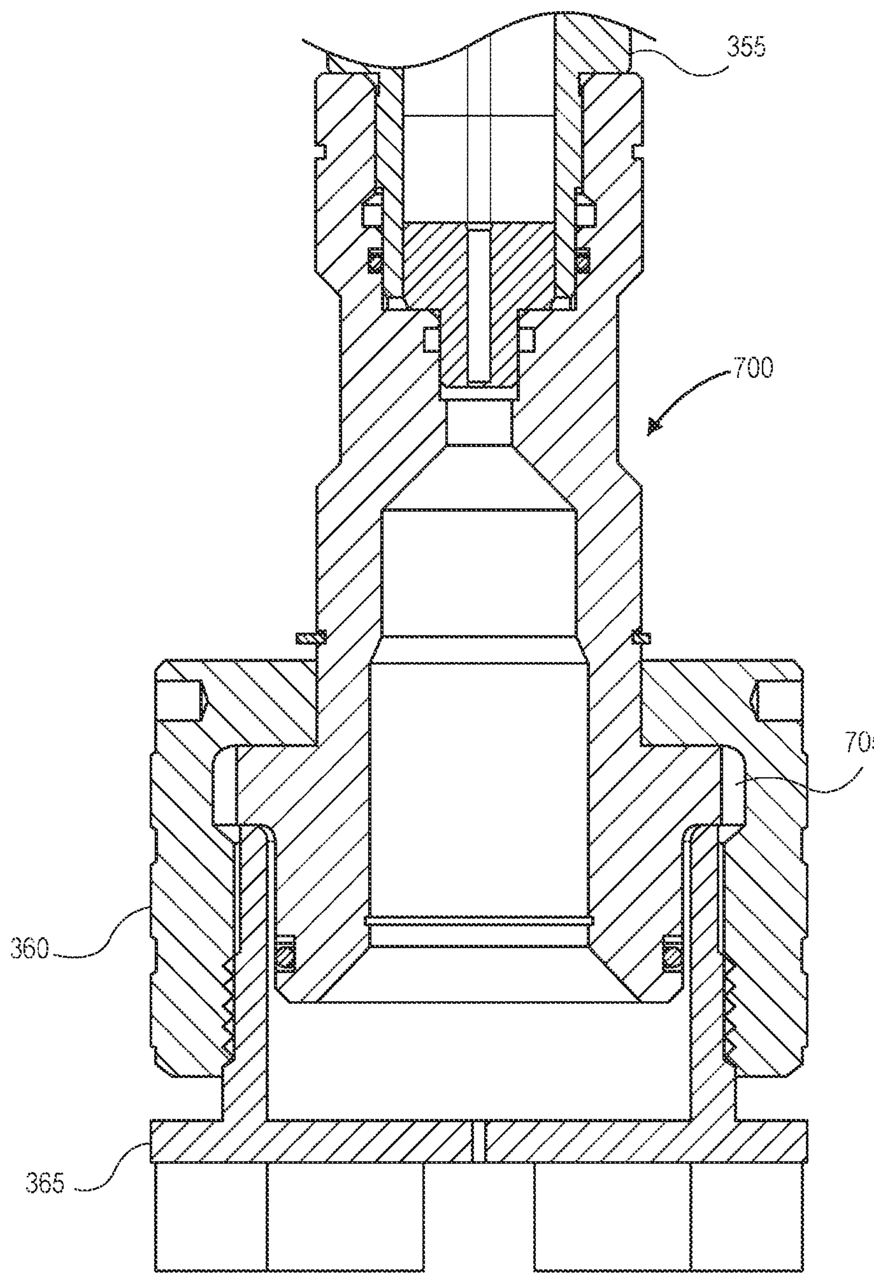

FIG. 7B

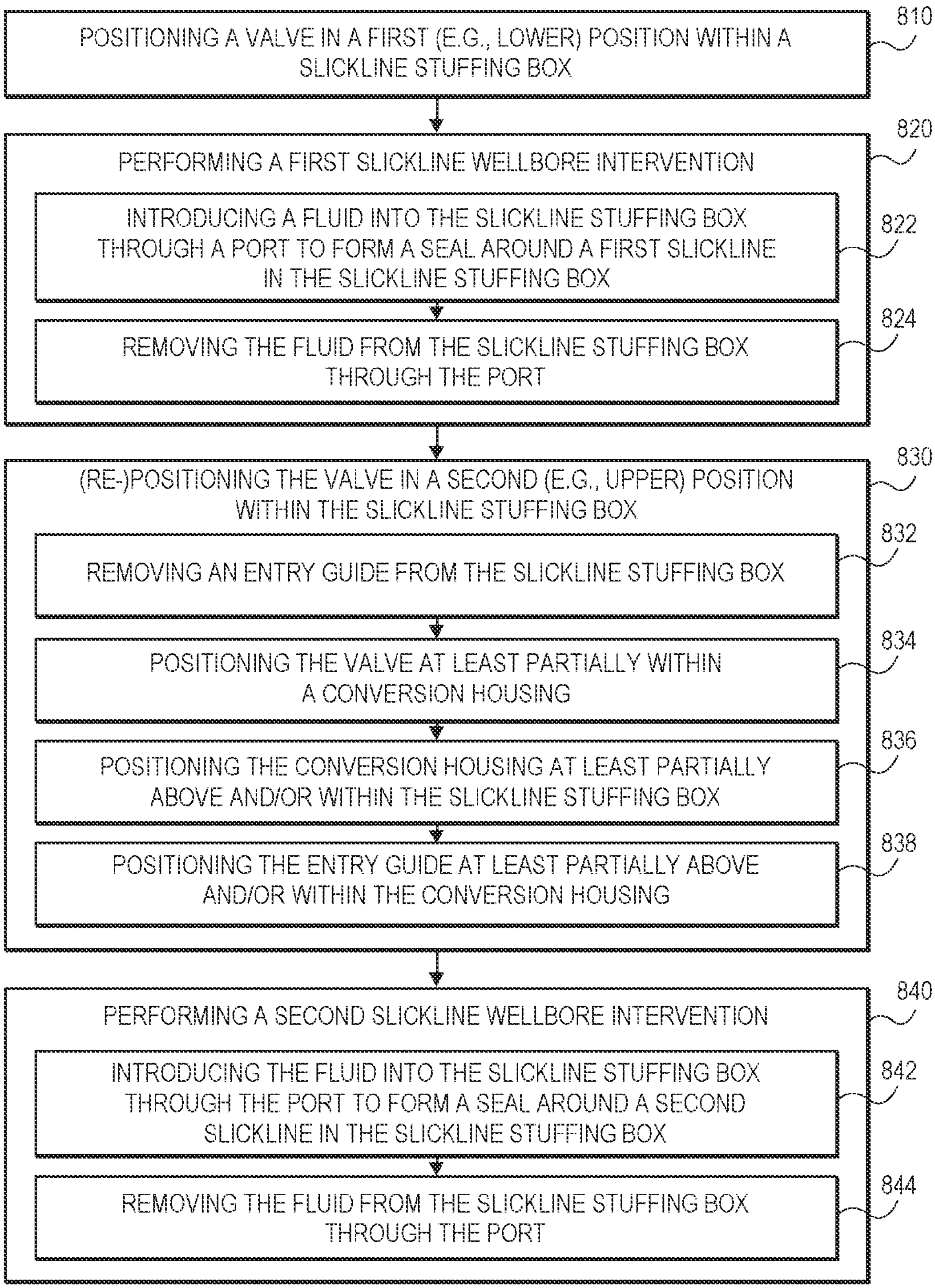
POSITIONING A VALVE IN A FIRST (E.G., LOWER) POSITION WITHIN A SLICKLINE STUFFING BOX
810
PERFORMING A FIRST SLICKLINE WELLBORE INTERVENTION
820
INTRODUCING A FLUID INTO THE SLICKLINE STUFFING BOX THROUGH A PORT TO FORM A SEAL AROUND A FIRST SLICKLINE IN THE SLICKLINE STUFFING BOX
822
REMOVING THE FLUID FROM THE SLICKLINE STUFFING BOX THROUGH THE PORT
824
(RE-)POSITIONING THE VALVE IN A SECOND (E.G., UPPER) POSITION WITHIN THE SLICKLINE STUFFING BOX
830
REMOVING AN ENTRY GUIDE FROM THE SLICKLINE STUFFING BOX
832
POSITIONING THE VALVE AT LEAST PARTIALLY WITHIN A CONVERSION HOUSING
834
POSITIONING THE CONVERSION HOUSING AT LEAST PARTIALLY ABOVE AND/OR WITHIN THE SLICKLINE STUFFING BOX
836
POSITIONING THE ENTRY GUIDE AT LEAST PARTIALLY ABOVE AND/OR WITHIN THE CONVERSION HOUSING
838
PERFORMING A SECOND SLICKLINE WELLBORE INTERVENTION
840
INTRODUCING THE FLUID INTO THE SLICKLINE STUFFING BOX THROUGH THE PORT TO FORM A SEAL AROUND A SECOND SLICKLINE IN THE SLICKLINE STUFFING BOX
842
REMOVING THE FLUID FROM THE SLICKLINE STUFFING BOX THROUGH THE PORT
844

FIG. 8

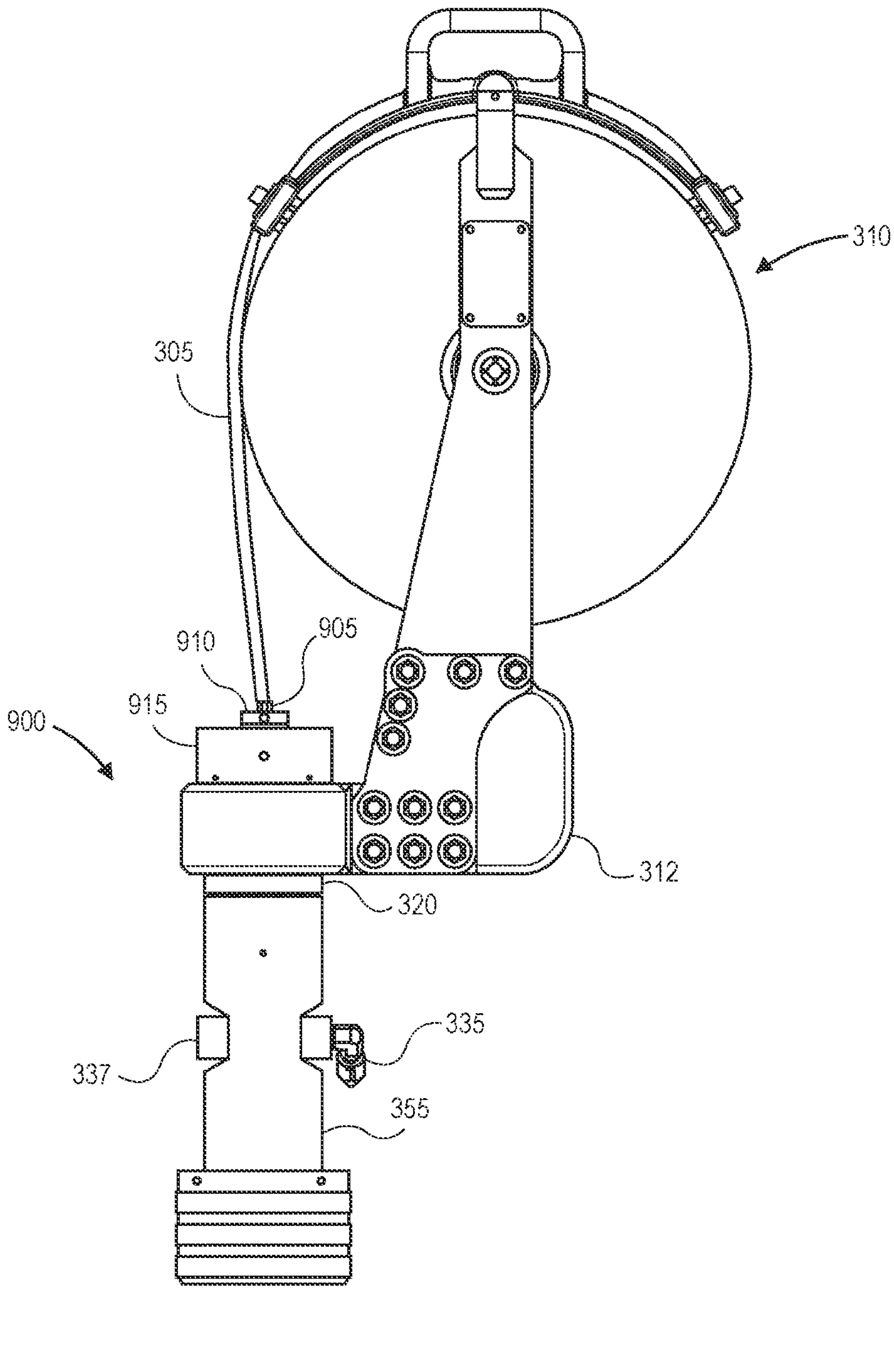

FIG. 9A

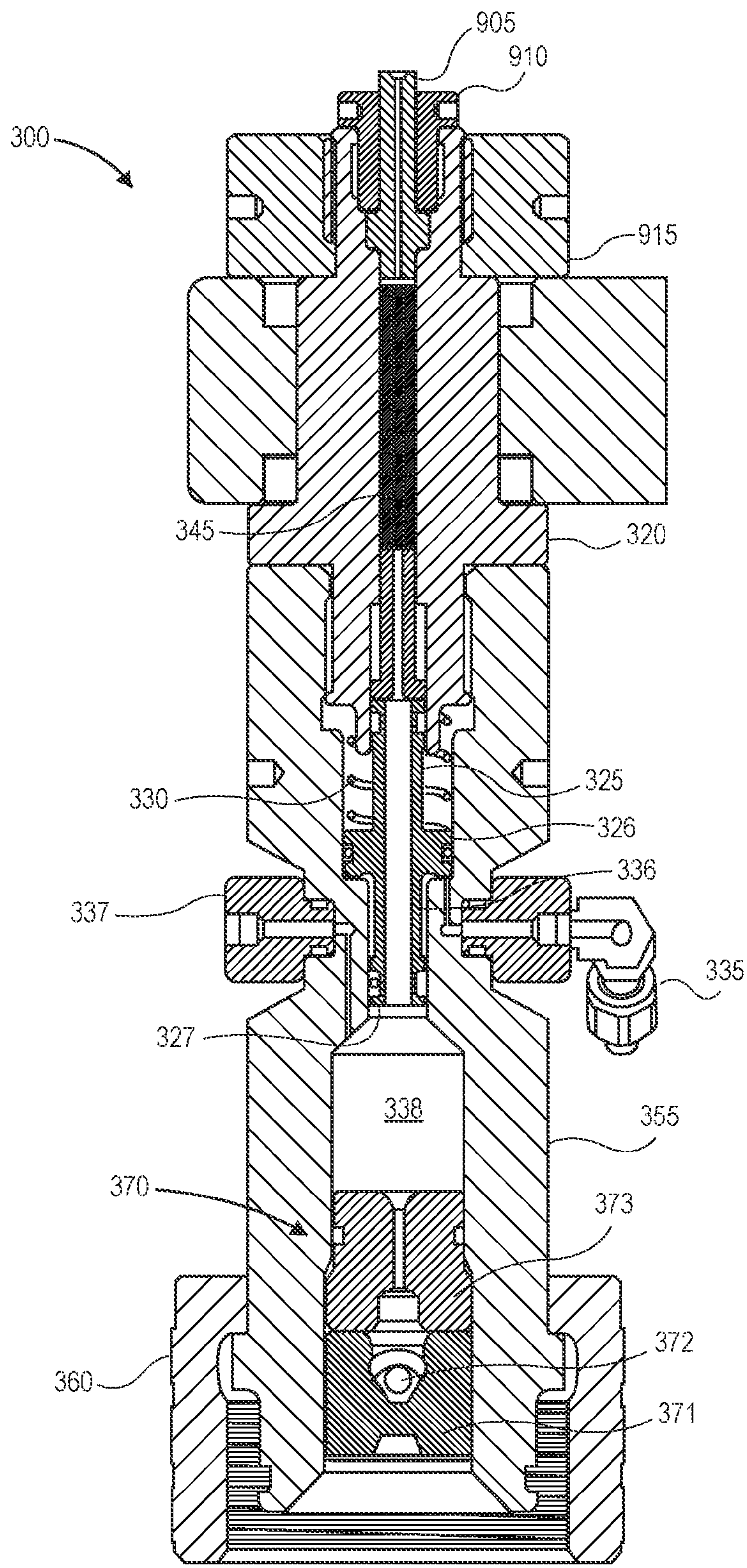
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FIG. 9B

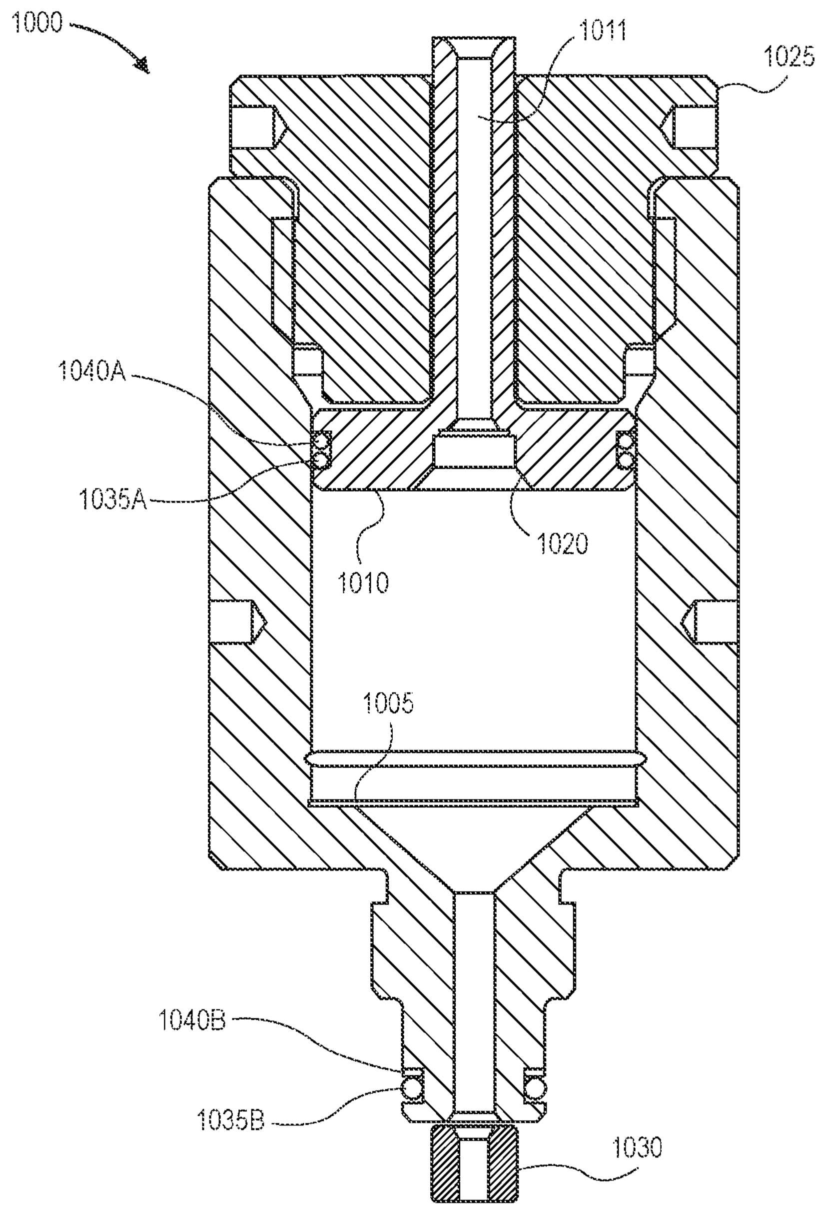

FIG. 10A

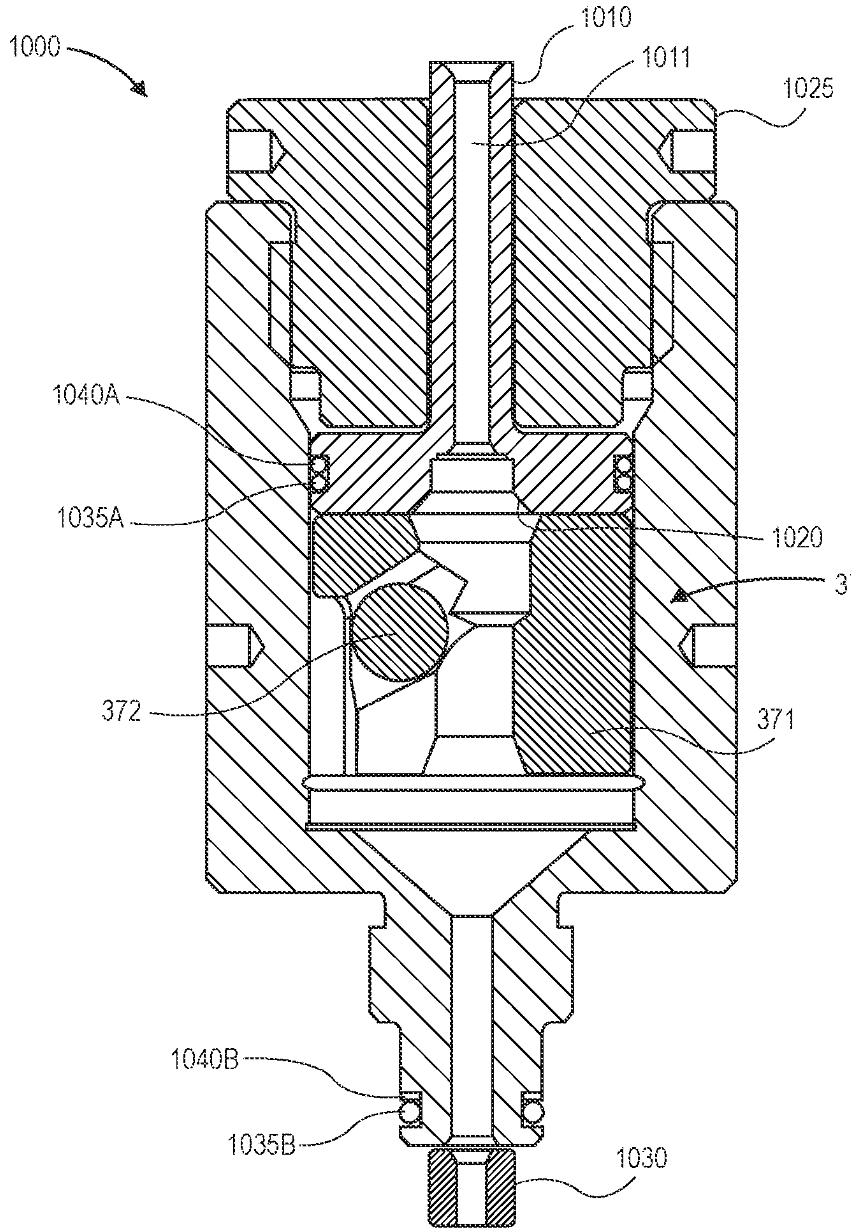
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FIG. 10B

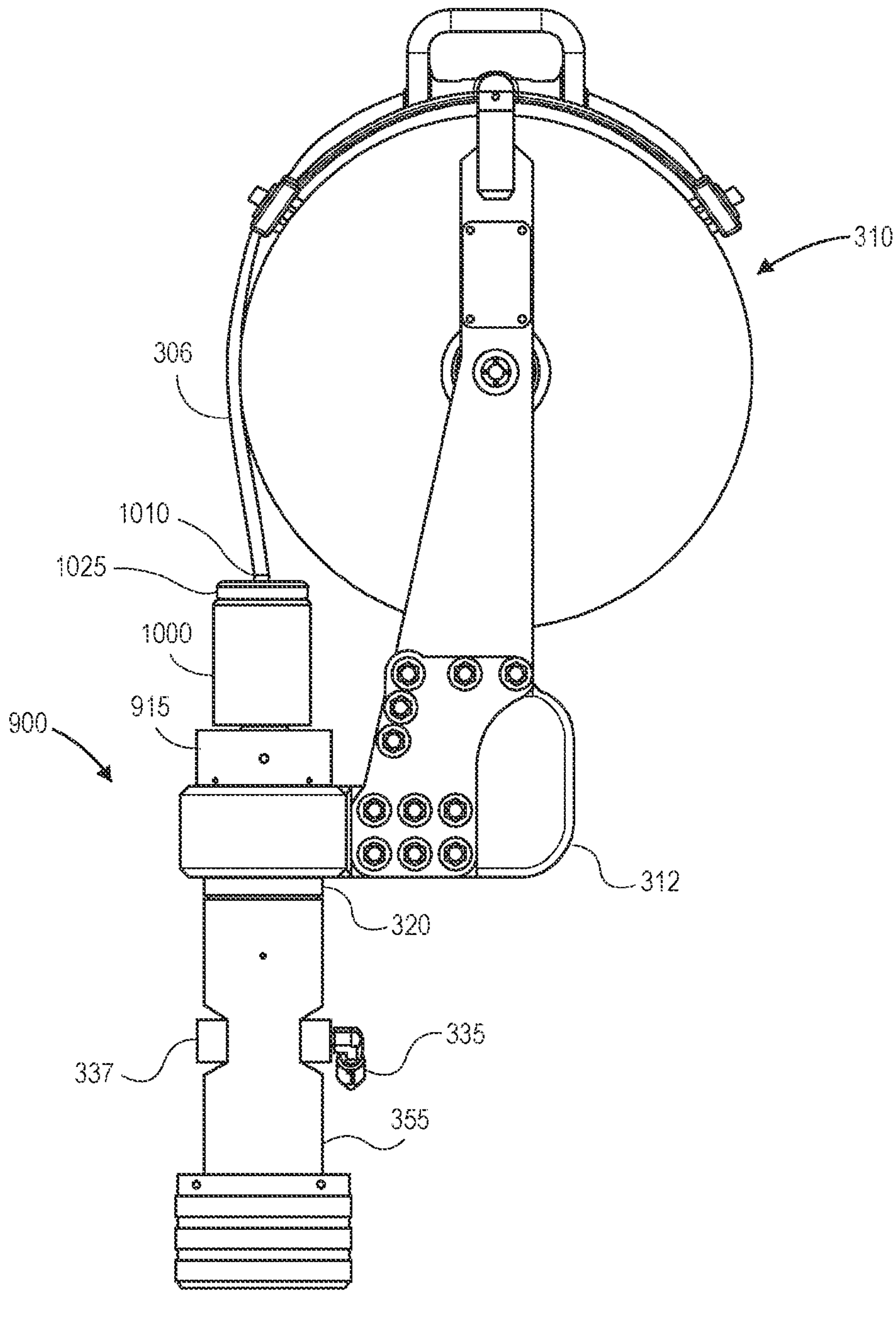

FIG. 11A

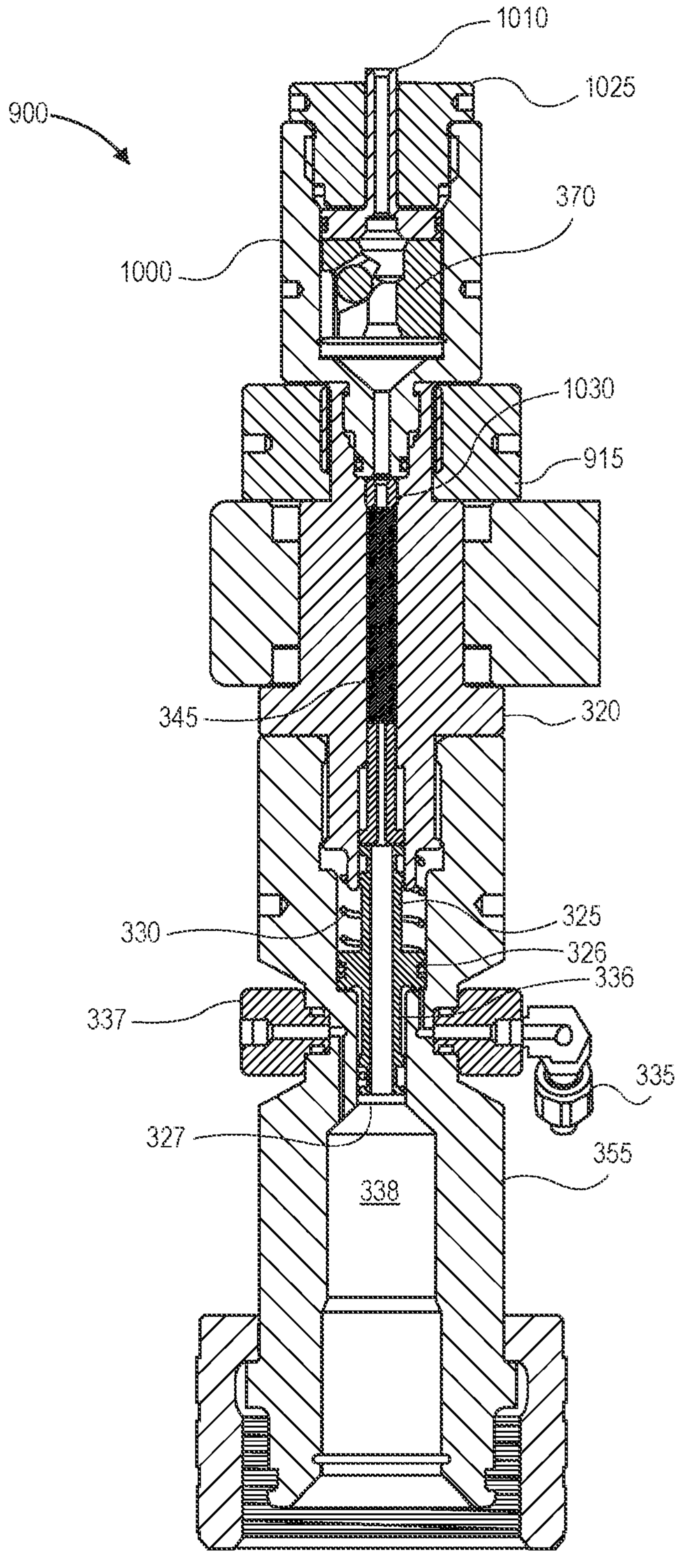
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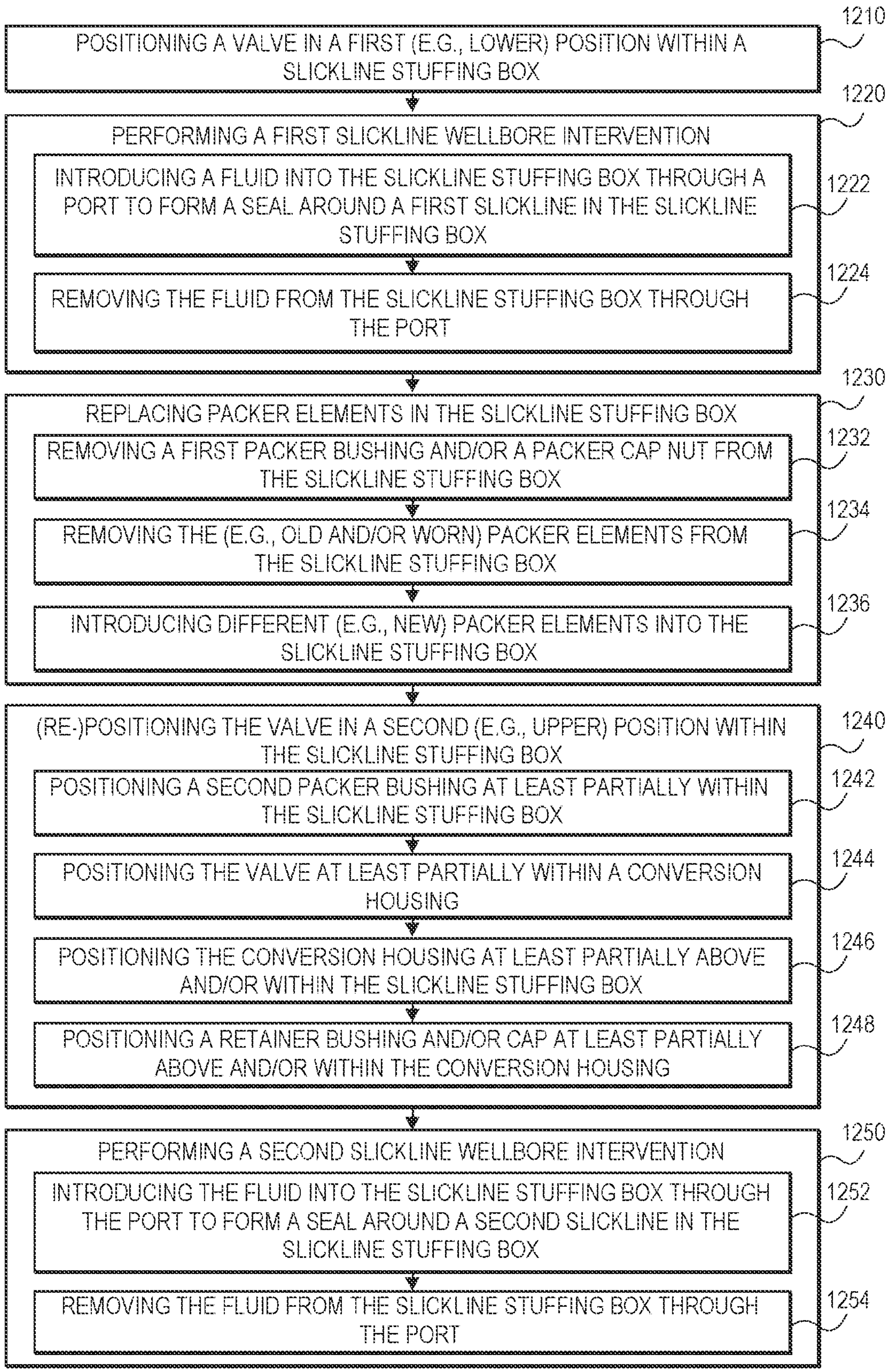
FIG. 11B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POSITIONING A VALVE IN A FIRST (E.G., LOWER) POSITION WITHIN A SLICKLINE STUFFING BOX
1220
PERFORMING A FIRST SLICKLINE WELLBORE INTERVENTION
1222
INTRODUCING A FLUID INTO THE SLICKLINE STUFFING BOX THROUGH A PORT TO FORM A SEAL AROUND A FIRST SLICKLINE IN THE SLICKLINE STUFFING BOX
1224
REMOVING THE FLUID FROM THE SLICKLINE STUFFING BOX THROUGH THE PORT
1230
REPLACING PACKER ELEMENTS IN THE SLICKLINE STUFFING BOX
1232
REMOVING A FIRST PACKER BUSHING AND/OR A PACKER CAP NUT FROM THE SLICKLINE STUFFING BOX
1234
REMOVING THE (E.G., OLD AND/OR WORN) PACKER ELEMENTS FROM THE SLICKLINE STUFFING BOX
1236
INTRODUCING DIFFERENT (E.G., NEW) PACKER ELEMENTS INTO THE SLICKLINE STUFFING BOX
1240
(RE-)POSITIONING THE VALVE IN A SECOND (E.G., UPPER) POSITION WITHIN THE SLICKLINE STUFFING BOX
1242
POSITIONING A SECOND PACKER BUSHING AT LEAST PARTIALLY WITHIN THE SLICKLINE STUFFING BOX
1244
POSITIONING THE VALVE AT LEAST PARTIALLY WITHIN A CONVERSION HOUSING
1246
POSITIONING THE CONVERSION HOUSING AT LEAST PARTIALLY ABOVE AND/OR WITHIN THE SLICKLINE STUFFING BOX
1248
POSITIONING A RETAINER BUSHING AND/OR CAP AT LEAST PARTIALLY ABOVE AND/OR WITHIN THE CONVERSION HOUSING
1250
PERFORMING A SECOND SLICKLINE WELLBORE INTERVENTION
1252
INTRODUCING THE FLUID INTO THE SLICKLINE STUFFING BOX THROUGH THE PORT TO FORM A SEAL AROUND A SECOND SLICKLINE IN THE SLICKLINE STUFFING BOX
1254
REMOVING THE FLUID FROM THE SLICKLINE STUFFING BOX THROUGH THE PORT

FIG. 12

CONVERTIBLE SLICKLINE STUFFING BOX

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application claims priority to U.S. Provisional Patent Application No. 63/377,867, filed Sep. 30, 2022, the entirety of which is incorporated by reference herein.

BACKGROUND

[0002] A slickline refers to a single strand wire (e.g., a cable) that is used during drilling operations in the oil and gas industry to run a variety of tools down into and/or out of a wellbore. A slickline stuffing box provides a seal around the slickline when the tool is being run into and/or pulled out of the wellbore while performing a slickline well intervention. Conventional slickline stuffing boxes have a ball check valve (BCV) below a packer. However, some slickline jobs use the BCV above the packer, and conventional slickline stuffing boxes cannot be converted in the field to move the BCV above the packer.

SUMMARY

[0003] This summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to identify key or essential features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter.

[0004] A slickline stuffing box is disclosed. The slickline stuffing box includes a piston configured to move in response to a force exerted thereon by a pressurized fluid. The slickline stuffing box also includes a packer element positioned above the piston. The packer element is configured to compress axially and expand radially, in response to movement of the piston, to seal around a slickline to contain a pressure within a wellbore during a slickline wellbore intervention. The slickline stuffing box also includes a valve configured to be positioned below the packer element in a first configuration of the slickline stuffing box and above the packer element in a second configuration of the slickline stuffing box. The valve is configured to contain the pressure within the wellbore in response to the slickline breaking and falling down and out of the slickline stuffing box.

[0005] In another embodiment, the slickline stuffing box includes a housing defining an inner shoulder. The slickline stuffing box also includes a ball check valve (BCV) configured to be positioned at least partially within the housing. The BCV includes a ball. The slickline stuffing box also includes a retainer bushing configured to be positioned at least partially within the housing. The BCV is configured to be positioned vertically between the retainer bushing and the inner shoulder of the housing. A lower surface of the retainer bushing defines a downward-facing seat, and wherein the ball is configured to seal with the seat to contain a pressure within a wellbore in response to a slickline breaking and falling down and out of the slickline stuffing box. The slickline stuffing box also includes a cap configured to be positioned at least partially within the housing and at least partially around the retainer bushing. The slickline stuffing box also includes an upper body coupled to and positioned at least partially below the housing. The housing is positioned at least partially within the upper body. The slickline stuffing box also includes one or more packer elements positioned at least partially within the upper body. The slickline stuffing box also includes a lower body coupled to and positioned at least partially below the upper body. The slickline stuffing box also includes a piston positioned at least partially within the lower body. The slickline stuffing box also includes a biasing member positioned at least partially within the lower body. The slickline stuffing box also includes a port coupled to the lower body. The port provides a path of fluid communication between an exterior of the lower body and a chamber within the lower body. The piston moves and compresses the biasing member and the one or more packer elements in response to a fluid flowing into the chamber. The one or more packer elements expand radially in response to being compressed, which causes the one or more packer elements to seal around the slickline to contain the pressure within the wellbore during a slickline wellbore intervention.

[0006] A method is also disclosed. The method includes removing a first packer bushing from a slickline stuffing box. The method also includes removing a first packer element from the slickline stuffing box while the first packer bushing is removed without decoupling a sheave wheel assembly from the slickline stuffing box. The method also includes introducing a second packer element into the slickline stuffing box while the first packer bushing is removed and after the first packer element is removed.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] The accompanying drawings, which are incorporated in and constitute a part of this specification, illustrate embodiments of the present teachings and together with the description, serve to explain the principles of the present teachings. In the figures:

[0008] FIG. **1** illustrates a conceptual, schematic view of a control system for a drilling rig, according to an embodiment.

[0009] FIG. **2** illustrates a conceptual, schematic view of the control system, according to an embodiment.

[0010] FIG. **3**A illustrates a side view of a slickline stuffing box in a first configuration, according to an embodiment.

[0011] FIG. **3**B illustrates a cross-sectional side view of the slickline stuffing box in the first configuration, according to an embodiment.

[0012] FIG. **4**A illustrates a cross-sectional side view of a conversion housing that is configured to be positioned at least partially in and/or coupled to the slickline stuffing box, according to an embodiment.

[0013] FIG. **4**B illustrates a cross-sectional side view of the conversion housing with a valve positioned therein, according to an embodiment.

[0014] FIG. **5**A illustrates a side view of the slickline stuffing box in a second configuration, according to an embodiment.

[0015] FIG. **5**B illustrates a cross-sectional side view of the slickline stuffing box in the second configuration, according to an embodiment.

[0016] FIG. **6**A illustrates a cross-sectional side view of a portion of the slickline stuffing box showing a piston, a biasing member, and a port, according to an embodiment.

[0017] FIG. **6**B illustrates a cross-sectional side view of a portion of the slickline stuffing box showing a packer housing and packer elements, according to an embodiment.

[0018] FIG. **6**C illustrates a top view of the packer elements, according to an embodiment.

[0019] FIG. **7**A illustrates a perspective view of a sheave wheel assembly, according to an embodiment.

[0020] FIG. **7**B illustrates a cross-sectional side view of an adapter positioned at least partially within the slickline stuffing box, according to an embodiment.

[0021] FIG. **8** illustrates a flowchart of a method for converting the slickline stuffing box to move the valve from a first (e.g., lower) position to a second (e.g., upper) position, according to an embodiment.

[0022] FIG. **9**A illustrates a side view of another slickline stuffing box in a first configuration, according to an embodiment.

[0023] FIG. **9**B illustrates a cross-sectional side view of the slickline stuffing box in the first configuration, according to an embodiment.

[0024] FIG. **10**A illustrates a cross-sectional side view of a conversion housing that is configured to be positioned at least partially in and/or coupled to the slickline stuffing box (in FIGS. **9**A and **9**B), according to an embodiment.

[0025] FIG. **10**B illustrates a cross-sectional side view of the conversion housing with a valve positioned therein, according to an embodiment.

[0026] FIG. **11**A illustrates a side view of the slickline stuffing box (from FIGS. **9**A and **9**B) in a second configuration, according to an embodiment.

[0027] FIG. **11**B illustrates a cross-sectional side view of the slickline stuffing box in the second configuration, according to an embodiment.

[0028] FIG. **12** illustrates a flowchart of a method for converting the slickline stuffing box to move the valve from a first (e.g., lower) position to a second (e.g., upper) position, according to an embodiment.

DETAILED DESCRIPTION

[0029] Reference will now be made in detail to specific embodiments illustrated in the accompanying drawings and figures. In the following detailed description, numerous specific details are set forth in order to provide a thorough understanding of the invention. However, it will be apparent to one of ordinary skill in the art that embodiments may be practiced without these specific details. In other instances, well-known methods, procedures, components, circuits, and networks have not been described in detail so as not to unnecessarily obscure aspects of the embodiments.

[0030] It will also be understood that, although the terms first, second, etc. may be used herein to describe various elements, these elements should not be limited by these terms. These terms are only used to distinguish one element from another. For example, a first object could be termed a second object or step, and, similarly, a second object could be termed a first object or step, without departing from the scope of the present disclosure.

[0031] The terminology used in the description of the invention herein is for the purpose of describing particular embodiments only and is not intended to be limiting. As used in the description of the invention and the appended claims, the singular forms "a," "an" and "the" are intended to include the plural forms as well, unless the context clearly indicates otherwise. It will also be understood that the term "and/or" as used herein refers to and encompasses any and all possible combinations of one or more of the associated listed items. It will be further understood that the terms "includes," "including," "comprises" and/or "comprising," when used in this specification, specify the presence of stated features, integers, steps, operations, elements, and/or components, but do not preclude the presence or addition of one or more other features, integers, steps, operations, elements, components, and/or groups thereof. Further, as used herein, the term "if" may be construed to mean "when" or "upon" or "in response to determining" or "in response to detecting," depending on the context.

[0032] FIG. **1** illustrates a conceptual, schematic view of a control system **100** for a drilling rig **102**, according to an embodiment. The control system **100** may include a rig computing resource environment **105**, which may be located onsite at the drilling rig **102** and, in some embodiments, may have a coordinated control device **104**. The control system **100** may also provide a supervisory control system **107**. In some embodiments, the control system **100** may include a remote computing resource environment **106**, which may be located offsite from the drilling rig **102**.

[0033] The remote computing resource environment **106** may include computing resources locating offsite from the drilling rig **102** and accessible over a network. A "cloud" computing environment is one example of a remote computing resource. The cloud computing environment may communicate with the rig computing resource environment **105** via a network connection (e.g., a WAN or LAN connection). In some embodiments, the remote computing resource environment **106** may be at least partially located onsite, e.g., allowing control of various aspects of the drilling rig **102** onsite through the remote computing resource environment **105** (e.g., via mobile devices). Accordingly, "remote" should not be limited to any particular distance away from the drilling rig **102**.

[0034] Further, the drilling rig **102** may include various systems with different sensors and equipment for performing operations of the drilling rig **102**, and may be monitored and controlled via the control system **100**, e.g., the rig computing resource environment **105**. Additionally, the rig computing resource environment **105** may provide for secured access to rig data to facilitate onsite and offsite user devices monitoring the rig, sending control processes to the rig, and the like.

[0035] Various example systems of the drilling rig **102** are depicted in FIG. **1**. For example, the drilling rig **102** may include a downhole system **110**, a fluid system **112**, and a central system **114**. These systems **110**, **112**, **114** may also be examples of "subsystems" of the drilling rig **102**, as described herein. In some embodiments, the drilling rig **102** may include an information technology (IT) system **116**. The downhole system **110** may include, for example, a bottomhole assembly (BHA), mud motors, sensors, etc. disposed along the drill string, and/or other drilling equipment configured to be deployed into the wellbore. Accordingly, the downhole system **110** may refer to tools disposed in the wellbore, e.g., as part of the drill string used to drill the well.

[0036] The fluid system **112** may include, for example, drilling mud, pumps, valves, cement, mud-loading equipment, mud-management equipment, pressure-management equipment, separators, and other fluids equipment. Accordingly, the fluid system **112** may perform fluid operations of the drilling rig **102**.

[0037] The central system **114** may include a hoisting and rotating platform, top drives, rotary tables, kellys, drawworks, pumps, generators, tubular handling equipment, derricks, masts, substructures, and other suitable equipment.

Accordingly, the central system **114** may perform power generation, hoisting, and rotating operations of the drilling rig **102**, and serve as a support platform for drilling equipment and staging ground for rig operation, such as connection make up, etc. The IT system **116** may include software, computers, and other IT equipment for implementing IT operations of the drilling rig **102**.

[0038] The control system **100**, e.g., via the coordinated control device **104** of the rig computing resource environment **105**, may monitor sensors from multiple systems of the drilling rig **102** and provide control commands to multiple systems of the drilling rig **102**, such that sensor data from multiple systems may be used to provide control commands to the different systems of the drilling rig **102**. For example, the system **100** may collect temporally and depth aligned surface data and downhole data from the drilling rig **102** and store the collected data for access onsite at the drilling rig **102** or offsite via the rig computing resource environment **105**. Thus, the system **100** may provide monitoring capability. Additionally, the control system **100** may include supervisory control via the supervisory control system **107**.

[0039] In some embodiments, one or more of the downhole system **110**, fluid system **112**, and/or central system **114** may be manufactured and/or operated by different vendors. In such an embodiment, certain systems may not be capable of unified control (e.g., due to different protocols, restrictions on control permissions, safety concerns for different control systems, etc.). An embodiment of the control system **100** that is unified, may, however, provide control over the drilling rig **102** and its related systems (e.g., the downhole system **110**, fluid system **112**, and/or central system **114**, etc.). Further, the downhole system **110** may include one or a plurality of downhole systems. Likewise, fluid system **112**, and central system **114** may contain one or a plurality of fluid systems and central systems, respectively.

[0040] In addition, the coordinated control device **104** may interact with the user device(s) (e.g., human-machine interface(s)) **118**, **120**. For example, the coordinated control device **104** may receive commands from the user devices **118**, **120** and may execute the commands using two or more of the rig systems **110**, **112**, **114**, e.g., such that the operation of the two or more rig systems **110**, **112**, **114** act in concert and/or off-design conditions in the rig systems **110**, **112**, **114** may be avoided.

[0041] FIG. **2** illustrates a conceptual, schematic view of the control system **100**, according to an embodiment. The rig computing resource environment **105** may communicate with offsite devices and systems using a network **108** (e.g., a wide area network (WAN) such as the internet). Further, the rig computing resource environment **105** may communicate with the remote computing resource environment **106** via the network **108**. FIG. **2** also depicts the aforementioned example systems of the drilling rig **102**, such as the downhole system **110**, the fluid system **112**, the central system **114**, and the IT system **116**. In some embodiments, one or more onsite user devices **118** may also be included on the drilling rig **102**. The onsite user devices **118** may interact with the IT system **116**. The onsite user devices **118** may include any number of user devices, for example, stationary user devices intended to be stationed at the drilling rig **102** and/or portable user devices. In some embodiments, the onsite user devices **118** may include a desktop, a laptop, a smartphone, a personal data assistant (PDA), a tablet component, a wearable computer, or other suitable devices. In some embodiments, the onsite user devices **118** may communicate with the rig computing resource environment **105** of the drilling rig **102**, the remote computing resource environment **106**, or both.

[0042] One or more offsite user devices **120** may also be included in the system **100**. The offsite user devices **120** may include a desktop, a laptop, a smartphone, a personal data assistant (PDA), a tablet component, a wearable computer, or other suitable devices. The offsite user devices **120** may be configured to receive and/or transmit information (e.g., monitoring functionality) from and/or to the drilling rig **102** via communication with the rig computing resource environment **105**. In some embodiments, the offsite user devices **120** may provide control processes for controlling operation of the various systems of the drilling rig **102**. In some embodiments, the offsite user devices **120** may communicate with the remote computing resource environment **106** via the network **108**.

[0043] The user devices **118** and/or **120** may be examples of a human-machine interface. These devices **118**, **120** may allow feedback from the various rig subsystems to be displayed and allow commands to be entered by the user. In various embodiments, such human-machine interfaces may be onsite or offsite, or both.

[0044] The systems of the drilling rig **102** may include various sensors, actuators, and controllers (e.g., programmable logic controllers (PLCs)), which may provide feedback for use in the rig computing resource environment **105**. For example, the downhole system **110** may include sensors **122**, actuators **124**, and controllers **126**. The fluid system **112** may include sensors **128**, actuators **130**, and controllers **132**. Additionally, the central system **114** may include sensors **134**, actuators **136**, and controllers **138**. The sensors **122**, **128**, and **134** may include any suitable sensors for operation of the drilling rig **102**. In some embodiments, the sensors **122**, **128**, and **134** may include a camera, a pressure sensor, a temperature sensor, a flow rate sensor, a vibration sensor, a current sensor, a voltage sensor, a resistance sensor, a gesture detection sensor or device, a voice actuated or recognition device or sensor, or other suitable sensors.

[0045] The sensors described above may provide sensor data feedback to the rig computing resource environment **105** (e.g., to the coordinated control device **104**). For example, downhole system sensors **122** may provide sensor data **140**, the fluid system sensors **128** may provide sensor data **142**, and the central system sensors **134** may provide sensor data **144**. The sensor data **140**, **142**, and **144** may include, for example, equipment operation status (e.g., on or off, up or down, set or release, etc.), drilling parameters (e.g., depth, hook load, torque, etc.), auxiliary parameters (e.g., vibration data of a pump) and other suitable data. In some embodiments, the acquired sensor data may include or be associated with a timestamp (e.g., a date, time or both) indicating when the sensor data was acquired. Further, the sensor data may be aligned with a depth or other drilling parameter.

[0046] Acquiring the sensor data into the coordinated control device **104** may facilitate measurement of the same physical properties at different locations of the drilling rig **102**. In some embodiments, measurement of the same physical properties may be used for measurement redundancy to enable continued operation of the well. In yet another embodiment, measurements of the same physical properties at different locations may be used for detecting equipment conditions among different physical locations. In yet another embodiment, measurements of the same physical properties using different sensors may provide information about the relative quality of each measurement, resulting in a "higher" quality measurement being used for rig control, and process applications. The variation in measurements at different locations over time may be used to determine equipment performance, system performance, scheduled maintenance due dates, and the like. Furthermore, aggregating sensor data from each subsystem into a centralized environment may enhance drilling process and efficiency. For example, slip status (e.g., in or out) may be acquired from the sensors and provided to the rig computing resource environment **105**, which may be used to define a rig state for automated control. In another example, acquisition of fluid samples may be measured by a sensor and related with bit depth and time measured by other sensors. Acquisition of data from a camera sensor may facilitate detection of arrival and/or installation of materials or equipment in the drilling rig **102**. The time of arrival and/or installation of materials or equipment may be used to evaluate degradation of a material, scheduled maintenance of equipment, and other evaluations.

[0047] The coordinated control device **104** may facilitate control of individual systems (e.g., the central system **114**, the downhole system, or fluid system **112**, etc.) at the level of each individual system. For example, in the fluid system **112**, sensor data **128** may be fed into the controller **132**, which may respond to control the actuators **130**. However, for control operations that involve multiple systems, the control may be coordinated through the coordinated control device **104**. Examples of such coordinated control operations include the control of downhole pressure during tripping. The downhole pressure may be affected by both the fluid system **112** (e.g., pump rate and choke position) and the central system **114** (e.g. tripping speed). When it is desired to maintain certain downhole pressure during tripping, the coordinated control device **104** may be used to direct the appropriate control commands. Furthermore, for mode based controllers which employ complex computation to reach a control setpoint, which are typically not implemented in the subsystem PLC controllers due to complexity and high computing power demands, the coordinated control device **104** may provide the adequate computing environment for implementing these controllers.

[0048] In some embodiments, control of the various systems of the drilling rig **102** may be provided via a multi-tier (e.g., three-tier) control system that includes a first tier of the controllers **126**, **132**, and **138**, a second tier of the coordinated control device **104**, and a third tier of the supervisory control system **107**. The first tier of the controllers may be responsible for safety critical control operation, or fast loop feedback control. The second tier of the controllers may be responsible for coordinated controls of multiple equipment or subsystems, and/or responsible for complex model based controllers. The third tier of the controllers may be responsible for high level task planning, such as to command the rig system to maintain certain bottom hole pressure. In other embodiments, coordinated control may be provided by one or more controllers of one or more of the drilling rig systems **110**, **112**, and **114** without the use of a coordinated control device **104**. In such embodiments, the rig computing resource environment **105** may provide control processes directly to these controllers for coordinated control. For example, in some embodiments, the controllers **126** and the controllers **132** may be used for coordinated control of multiple systems of the drilling rig **102**.

[0049] The sensor data **140**, **142**, and **144** may be received by the coordinated control device **104** and used for control of the drilling rig **102** and the drilling rig systems **110**, **112**, and **114**. In some embodiments, the sensor data **140**, **142**, and **144** may be encrypted to produce encrypted sensor data **146**. For example, in some embodiments, the rig computing resource environment **105** may encrypt sensor data from different types of sensors and systems to produce a set of encrypted sensor data **146**. Thus, the encrypted sensor data **146** may not be viewable by unauthorized user devices (either offsite or onsite user device) if such devices gain access to one or more networks of the drilling rig **102**. The sensor data **140**, **142**, **144** may include a timestamp and an aligned drilling parameter (e.g., depth) as discussed above. The encrypted sensor data **146** may be sent to the remote computing resource environment **106** via the network **108** and stored as encrypted sensor data **148**.

[0050] The rig computing resource environment **105** may provide the encrypted sensor data **148** available for viewing and processing offsite, such as via offsite user devices **120**. Access to the encrypted sensor data **148** may be restricted via access control implemented in the rig computing resource environment **105**. In some embodiments, the encrypted sensor data **148** may be provided in real-time to offsite user devices **120** such that offsite personnel may view real-time status of the drilling rig **102** and provide feedback based on the real-time sensor data. For example, different portions of the encrypted sensor data **146** may be sent to offsite user devices **120**. In some embodiments, encrypted sensor data may be decrypted by the rig computing resource environment **105** before transmission or decrypted on an offsite user device after encrypted sensor data is received.

[0051] The offsite user device **120** may include a client (e.g., a thin client) configured to display data received from the rig computing resource environment **105** and/or the remote computing resource environment **106**. For example, multiple types of thin clients (e.g., devices with display capability and minimal processing capability) may be used for certain functions or for viewing various sensor data.

[0052] The rig computing resource environment **105** may include various computing resources used for monitoring and controlling operations such as one or more computers having a processor and a memory. For example, the coordinated control device **104** may include a computer having a processor and memory for processing sensor data, storing sensor data, and issuing control commands responsive to sensor data. As noted above, the coordinated control device **104** may control various operations of the various systems of the drilling rig **102** via analysis of sensor data from one or more drilling rig systems (e.g. **110**, **112**, **114**) to enable coordinated control between each system of the drilling rig **102**. The coordinated control device **104** may execute control commands **150** for control of the various systems of the drilling rig **102** (e.g., drilling rig systems **110**, **112**, **114**). The coordinated control device **104** may send control data determined by the execution of the control commands **150** to one or more systems of the drilling rig **102**. For example, control data **152** may be sent to the downhole system **110**, control data **154** may be sent to the fluid system **112**, and control data **154** may be sent to the central system **114**. The control data may include, for example, operator commands (e.g., turn on or off a pump, switch on or off a valve, update a physical property setpoint, etc.). In some embodiments, the coordinated control device **104** may include a fast control loop that directly obtains sensor data **140**, **142**, and **144** and executes, for example, a control algorithm. In some embodiments, the coordinated control device **104** may include a slow control loop that obtains data via the rig computing resource environment **105** to generate control commands.

[0053] In some embodiments, the coordinated control device **104** may intermediate between the supervisory control system **107** and the controllers **126**, **132**, and **138** of the systems **110**, **112**, and **114**. For example, in such embodiments, a supervisory control system **107** may be used to control systems of the drilling rig **102**. The supervisory control system **107** may include, for example, devices for entering control commands to perform operations of systems of the drilling rig **102**. In some embodiments, the coordinated control device **104** may receive commands from the supervisory control system **107**, process the commands according to a rule (e.g., an algorithm based upon the laws of physics for drilling operations), and/or control processes received from the rig computing resource environment **105**, and provides control data to one or more systems of the drilling rig **102**. In some embodiments, the supervisory control system **107** may be provided by and/or controlled by a third party. In such embodiments, the coordinated control device **104** may coordinate control between discrete supervisory control systems and the systems **110**, **112**, and **114** while using control commands that may be optimized from the sensor data received from the systems **110 112**, and **114** and analyzed via the rig computing resource environment **105**.

[0054] The rig computing resource environment **105** may include a monitoring process **141** that may use sensor data to determine information about the drilling rig **102**. For example, in some embodiments the monitoring process **141** may determine a drilling state, equipment health, system health, a maintenance schedule, or any combination thereof. Furthermore, the monitoring process **141** may monitor sensor data and determine the quality of one or a plurality of sensor data. In some embodiments, the rig computing resource environment **105** may include control processes **143** that may use the sensor data **146** to optimize drilling operations, such as, for example, the control of drilling equipment to improve drilling efficiency, equipment reliability, and the like. For example, in some embodiments the acquired sensor data may be used to derive a noise cancellation scheme to improve electromagnetic and mud pulse telemetry signal processing. The control processes **143** may be implemented via, for example, a control algorithm, a computer program, firmware, or other suitable hardware and/or software. In some embodiments, the remote computing resource environment **106** may include a control process **145** that may be provided to the rig computing resource environment **105**.

[0055] The rig computing resource environment **105** may include various computing resources, such as, for example, a single computer or multiple computers. In some embodiments, the rig computing resource environment **105** may include a virtual computer system and a virtual database or other virtual structure for collected data. The virtual computer system and virtual database may include one or more resource interfaces (e.g., web interfaces) that enable the submission of application programming interface (API) calls to the various resources through a request. In addition, each of the resources may include one or more resource interfaces that enable the resources to access each other (e.g., to enable a virtual computer system of the computing resource environment to store data in or retrieve data from the database or other structure for collected data).

[0056] The virtual computer system may include a collection of computing resources configured to instantiate virtual machine instances. The virtual computing system and/or computers may provide a human-machine interface through which a user may interface with the virtual computer system via the offsite user device or, in some embodiments, the onsite user device. In some embodiments, other computer systems or computer system services may be utilized in the rig computing resource environment **105**, such as a computer system or computer system service that provisions computing resources on dedicated or shared computers/servers and/or other physical devices. In some embodiments, the rig computing resource environment **105** may include a single server (in a discrete hardware component or as a virtual server) or multiple servers (e.g., web servers, application servers, or other servers). The servers may be, for example, computers arranged in any physical and/or virtual configuration

[0057] In some embodiments, the rig computing resource environment **105** may include a database that may be a collection of computing resources that run one or more data collections. Such data collections may be operated and managed by utilizing API calls. The data collections, such as sensor data, may be made available to other resources in the rig computing resource environment or to user devices (e.g., onsite user device **118** and/or offsite user device **120**) accessing the rig computing resource environment **105**. In some embodiments, the remote computing resource environment **106** may include similar computing resources to those described above, such as a single computer or multiple computers (in discrete hardware components or virtual computer systems).

Convertible Slickline Stuffing Box

[0058] The present disclosure includes a convertible slickline stuffing box. The slickline stuffing box is configured to be converted between a first configuration and a second configuration. In the first configuration, a valve may be positioned in a lower portion of the slickline stuffing box (e.g., below one or more packing elements), and in the second configuration, the valve may be positioned in an upper portion of the slickline stuffing box (e.g., above the one or more packing elements).

[0059] As described in greater detail below, a slickline may run through the slickline stuffing box, and a downhole tool may be coupled (i.e., rigged up) to a lower end of the slickline below the slickline stuffing box. The slickline and the downhole tool may be used to perform a slickline wellbore intervention in a wellbore. As used herein, a slickline wellbore intervention refers to an operation carried out in the wellbore during, or at the end of, its productive life that alters the state of the wellbore or wellbore geometry, provides wellbore diagnostics, and/or manages the production of the wellbore.

[0060] During the slickline wellbore intervention, the slickline stuffing box may be configured to form a seal around the slickline to control/contain the pressure in the wellbore below the seal. The valve may be in the first configuration to perform a first slickline wellbore intervention, and the valve may be converted into the second configuration to perform a second slickline wellbore intervention. The first and second slickline wellbore interventions may be different. In one embodiment, the slickline used during the first slickline wellbore intervention may be a non-digital slickline, and the slickline used during the second slickline wellbore intervention may be a digital slickline. The slickline wellbore interventions may be performed in any order. For example, the first slickline wellbore intervention may be performed before, after, and/or simultaneously with the second slickline wellbore intervention.

[0061] FIGS. **3**A and **3**B illustrate a side view and a cross-sectional side view of a slickline stuffing box **300** in a first configuration where a valve **370** is in a lower portion of the slickline stuffing box **300**, according to an embodiment. The slickline stuffing box **300** may be positioned above a pressure control equipment (PCE) stack and a wellbore. A slickline **305** may extend (e.g., vertically) through the slickline stuffing box **300**, the PCE stack, and into the wellbore.

[0062] The slickline **305** may be positioned at least partially around a sheave wheel assembly **310**, as shown in FIG. **3**A. The sheave wheel assembly **310** may be configured to rotate to run the slickline **305** (e.g., down) through the slickline stuffing box **300** and into the wellbore and/or to pull the slickline **305** (e.g., up) through the slickline stuffing box **300** and out of the wellbore.

[0063] A first (e.g., upper) end of the slickline stuffing box **300** may include an entry guide **315**. The entry guide **315** may receive and guide a slickline **305** into the slickline stuffing box **300**.

[0064] The slickline stuffing box **300** may also include a first (e.g., upper) body **320**. The upper body **320** may be positioned at least partially below and/or around the entry guide **315**. The sheave wheel assembly **310** may be coupled to the upper body **320**.

[0065] The slickline stuffing box **300** may also include a piston **325** that is positioned at least partially within the upper body **320**. The piston **325** may be configured to move/actuate (e.g., up and/or down) within the upper body **320** to form a seal around the slickline **305**, as discussed in greater detail below. The piston **325** may be symmetric such that the piston **325** cannot be installed upside-down. More particularly, the shape of the piston **325** and the locations of one or more seals (three are shown: **328**A-**328**C) positioned thereabout may be symmetric through a (e.g., horizontal) plane through a shoulder **326** of the piston **325**.

[0066] The slickline stuffing box **300** may also include a biasing member (e.g., a spring) **330**. The biasing member **330** may be positioned at least partially within the upper body **320**. The biasing member **330** may also be positioned at least partially below a shoulder **326** of the piston **325** and/or around a lower stem **327** of the piston **325**. The biasing member **330** may be configured to compress and/or expand. More particularly, as the biasing member **330** is compressed, it may exert an increasing axial (e.g., upward) force on the piston **325**.

[0067] The slickline stuffing box **300** may also include a port (also referred to as an operating port) **335**. The port **335** may be coupled to and/or part of the upper body **320**. In one embodiment, a pressurized fluid may be introduced through the port **335** and into the upper body **320** (e.g., above the shoulder of the piston **325**). As described in greater detail below, when introduced through the port **335**, the fluid may push the piston **325** downward, which may form a seal around the slickline **305** during a slickline wellbore intervention. After the slickline wellbore intervention, the fluid may flow back out of the slickline stuffing box **300** through the port **335**.

[0068] The slickline stuffing box **300** may also include a packer housing **340**. The packer housing **340** may be positioned at least partially below the upper housing **320**, the piston **325**, the biasing member **330**, and/or the port **335**. At least a portion of the packer housing **340** may be positioned radially inward from the upper body **320** and radially outward from the piston **325**. The packer housing **340** may be coupled (e.g., threaded) to the upper housing **320**. The packer housing **340** may guide (e.g., the lower stem **327** of) the piston **325** as the piston **325** moves. The packer housing **340** may also contain the wellbore pressure.

[0069] The slickline stuffing box **300** may also include one or more packer elements **345**. For example, there may be seven 1-inch packer elements **345**. More particularly, the packer elements **345** may be positioned at least partially within the packer housing **340**. The slickline **305** may extend through the packer elements **345**. The packer elements **345** may be or include elastomeric (e.g., rubber) elements that are configured to compress in response to the piston **325** moving downward. The packer elements **345** may expand radially (e.g., inward and/or outward) when compressed. This radial expansion may allow the packer elements **345** to create a static and/or dynamic seal with the outer surface of the slickline **305** and/or the inner surface of the packer housing **340**. In one embodiment, one or more (e.g., brass) bushings **350**A, **350**B may be positioned at least partially within the packer housing **340** and at least partially above and/or below the packer elements **345** to prevent the packer elements **345** from extruding axially out of the packer housing **340**.

[0070] The slickline stuffing box **300** may also include a second (e.g., lower) body **355**. The lower body **355** may be positioned at least partially below and/or at least partially around the packer housing **340**. The lower body **355** may be coupled (e.g., threaded) to the packer housing **340**. The upper body **320**, the packer housing **340**, and the lower body **355** may contain the pressure of the fluid therein (i.e., the wellbore pressure). The lower body **355** may include a pin connection with a collar **360** that is configured to be connected to a box connection on other equipment (e.g., a thread protector and/or PCE) **365** positioned below the lower body **355**.

[0071] The slickline stuffing box **300** may also include a valve **370**. The valve **370** may be or include a ball check valve (BCV) including a valve body **371**, a ball **372** within the valve body **371**, and a retainer **373**. The retainer **373** may include or define a downward-facing seat **374** that is configured to receive the ball **372** when the wellbore pressure pushes the ball **372** upward. The ball **372** may form a seal against the seat **374** to control/contain the wellbore pressure therebelow.

[0072] The slickline **305** may extend through the valve **370**. The valve **370** may be configured to create a wellbore seal if/when the slickline **305** breaks and falls down and out of the slickline stuffing box **300** (e.g., to prevent the wellbore pressure from being released up through the slickline stuffing box **300**).

[0073] In the embodiment shown, where the slickline stuffing box **300** is in the first configuration, the valve **370** may be positioned in the lower portion of the slickline stuffing box **300**. More particularly, the valve **370** may be positioned below the packer housing **340** and the packer elements **345** and at least partially within the lower body **355**. The valve **370** may be in this position when the first slickline wellbore intervention is performed. In an example, the first slickline wellbore intervention may use a first (e.g., non-digital) slickline **305** to perform well intervention operations such as capturing one or more measurements in the wellbore with the downhole tool, setting a plug in the wellbore, pulling the plug in the wellbore, fishing for an object at the bottom or the wellbore, or the like. In one embodiment, the non-digital slickline **305** may not be configured to communicate with equipment at the surface.

[0074] FIG. **4**A illustrates a cross-sectional side view of a conversion housing **400** that is configured to be coupled to and/or positioned at least partially within the slickline stuffing box **300**, and FIG. **4**B illustrates the conversion housing **400** with the valve **370** positioned therein, according to an embodiment. The conversion housing **400** may include or define a lower shoulder **405**, and the valve **370** may be configured to sit on the shoulder **405**. In one embodiment, the conversion housing **400** may be positioned at least partially below the entry guide **315** (FIGS. **3**A and **3**B), and the entry guide **315** may act as the retainer for the valve **370**. In another embodiment, the entry guide **315** may be removed or omitted, and the conversion housing **400** may include a different entry guide (also referred to as a bell or cap) **415** that acts as a retainer for the valve **370**. In other words, the valve **370** may be secured (e.g., vertically) between the shoulder **405** and the entry guide **315**, **415**.

[0075] The entry guide **315**, **415** may include or define a downward-facing seat **410** that is configured to receive the ball **372** when the wellbore pressure pushes the ball **372** upward. The ball **372** may form a seal against the seat **410** to control/contain the wellbore pressure therebelow. One or more seals (e.g., O-rings) **420** and/or one or more backup rings **425** may be positioned at least partially radially between the conversion housing **400** and the entry guide **315**, **415**.

[0076] FIGS. **5**A and **5**B illustrate a side view and a cross-sectional side view of the slickline stuffing box **300** in a second configuration, according to an embodiment. In the second configuration, the valve **370** may be moved/relocated proximate to an upper portion of the slickline stuffing box **300**. To accomplish this, the entry guide **315** may be removed, and the conversion housing **400** may be positioned above and/or at least partially within the upper body **320**. For example, the conversion housing **400** may include outer threads that are configured to engage inner threads of the upper body **320**.

[0077] The valve **370** may be positioned at least partially within the conversion housing **400**. The entry guide **315** or **415** may be positioned above and/or at least partially within the conversion housing **400**. As mentioned above, the valve **370** may be secured (e.g., vertically) between the shoulder **405** of the conversion housing **400** and the entry guide **315** or **415**. Thus, the conversion housing **400** may allow the valve **370** to be moved/relocated to be above the packer housing **340** and the packer elements **345**. The valve **370** may be in this position when the second slickline wellbore intervention is performed. In an example, the second slickline wellbore intervention may use a second (e.g., digital) slickline **306** to perform well intervention operations such with a downhole tool that is configured to communicate with equipment at the surface (e.g., real-time telemetry) using the digital slickline **306**. The digital slickline **306** (FIG. **5**B) may differ from the slickline **305** (FIG. **3**A) in that the digital slickline **306** may include a cable that is configured to transmit communication signals to and/or from the surface. The digital slickline **306** may also include a protective coating around the cable.

[0078] FIG. **6**A illustrates a cross-sectional side view of a portion of the slickline stuffing box **300** showing the piston **325**, the biasing member **330**, and the port **335**, and FIG. **6**B illustrates a cross-sectional side view of a portion of the slickline stuffing box **300** showing the packer housing **340** and the packer elements **345**, according to an embodiment. A pressurized fluid may be introduced through the port **335** and into the upper body **320** above the shoulder of the piston **325**. The pressure of the fluid may be, for example, from about 100 PSI to about 5000 PSI or from about 1000 PSI to about 4000 PSI (e.g., about 3000 PSI). This may be referred to as the operating pressure. The operating pressure may be greater than, less than, or equal to the pressure of the fluid in the wellbore (referred to as the wellbore pressure), which may be, for example, from about 6000 PSI to about 12,000 PSI or from about 8000 PSI to about 11,000 PSI (e.g., about 10,000 PSI).

[0079] The pressurized fluid may exert a downward force on the piston **325**, which causes the piston **325** to move downwards within the upper body **320**. The downward movement compresses the biasing member **330**. The downward movement also compresses the packer elements **345** within the packer housing **340**, which causes the packer elements **345** to expand radially inward and/or outward. As mentioned above, this expansion causes the packer elements **345** to form a (e.g., static and/or dynamic) seal with the slickline **305** and/or the packer housing **340** (e.g., during a slickline wellbore intervention).

[0080] After the slickline wellbore intervention, the operating pressure may be reduced (e.g., through the port **335**), which allows the biasing member **330** to push the piston **325** back up. One or more snap rings **600** may prevent the piston **325** from falling off during replacement of the packer elements **345**. The packer housing **340** may include an open bottom to facilitate removal and/or replacement of the packer elements **345**.

[0081] FIG. **6**C illustrates a top view of the packer elements **345**, according to an embodiment. The packer elements **345** may include a circumferential slot **346** that may facilitate removing, replacing, and/or installing the packer elements **345** while the slickline **305** is present. For example, the slickline **305** may slide radially through the slot **346** to a center portion **347** of the packer element **345**.

[0082] FIG. **7**A illustrates a perspective view of the sheave wheel assembly **310**, according to an embodiment. The sheave wheel assembly **310** may have a wheel **311** with a 16-inch diameter. The sheave wheel assembly **310** may also have a bracket assembly **312** that is configured to be coupled to the upper body **320**.

[0083] FIG. **7**B illustrates a cross-sectional side view of an adapter **700** that is configured to be positioned at least partially within the slickline stuffing box **300**, according to an embodiment. As shown, the adapter **700** may be positioned at least partially around and/or below the lower body **355**. The adapter **700** may include a (e.g., 3-inch) pin end **705** that is configured to engage with a tool catcher or other well intervention equipment (e.g., PCE). In another embodiment, the pin end **705** of the adapter **700** may instead be larger (e.g., 5-inches) to engage with a box end of a lubricator without changes to any other components.

[0084] FIG. **8** illustrates a flowchart of a method **800** for converting the slickline stuffing box **300** and/or performing a slickline wellbore intervention, according to an embodiment. An illustrative order of the method **800** is provided below; however, one or more portions of the method **800** may be performed in a different order, combined, repeated, or omitted.

[0085] The method **800** may include positioning the valve **370** in a first (e.g., lower) position within the slickline stuffing box **300**, as at **810**. This is shown in FIGS. **3**A and **3**B. The first position may be below the packer housing **340** and/or the packer elements **345**. The first position may also or instead be at least partially within the lower body **355**.

[0086] The method **800** may also include performing a first slickline wellbore intervention, as at **820**. The first slickline wellbore intervention may be performed using a first (e.g., non-digital) slickline **305** while the valve **370** is in the first position.

[0087] Performing the first slickline wellbore intervention may include introducing a fluid into the slickline stuffing box **300** through the port **335**, as at **822**. The fluid may be introduced into a chamber that is defined at least partially by the upper body **320** and the (e.g., shoulder **326** of the) piston **325**. The fluid may have a pressure such that when the fluid is introduced into the chamber, the fluid exerts a downward force on the piston **325** that exceeds an upward force exerted on the piston **325** by the biasing member **330**. As a result, the piston **325** moves downward, which compresses the biasing member **330** and the packer elements **345**. As mentioned above, compressing the packer elements **345** may create a static and/or dynamic seal with the outer surface of the slickline **305** and/or the inner surface of the packer housing **340**. This seal may allow the first slickline wellbore intervention to take place in the wellbore.

[0088] Performing the first slickline wellbore intervention may also include removing the fluid from the slickline stuffing box **300** through the port **335**, as at **824**. For example, after the first slickline wellbore intervention has occurred, the fluid may flow out of the chamber through the port **335**. This may allow the biasing member **330** to push the piston **325** back upward, which decompresses the biasing member **330** and the packer elements **345**.

[0089] The method **800** may also include (re-)positioning the valve **370** in a second (e.g., upper) position within the slickline stuffing box **300**, as at **830**. This is shown in FIGS. **5**A and **5**B. The second position may be above the packer housing **340** and/or the packer elements **345**. The second position may also or instead be above the upper body **320**. In one embodiment, the valve **370** may be (re-)positioned at the same wellbore and/or the same wellsite where the first slickline wellbore intervention occurred. In another embodiment, the valve **370** may be (re-)positioned at a different wellbore and/or a different wellsite than where the first slickline wellbore intervention occurred.

[0090] Positioning (or re-positioning) the valve **370** may include removing the entry guide **315**, as at **832**. More particularly, the entry guide **315** may be removed from the upper body **320**.

[0091] Positioning (or re-positioning) the valve **370** may also include positioning the valve **370** at least partially within the conversion housing **400**, as at **834**. More particularly, the valve **370** may be positioned on and/or above (or otherwise in contact with) the shoulder **405** in the conversion housing **400**.

[0092] Positioning (or re-positioning) the valve **370** may also include positioning the conversion housing **400** at least partially above and/or within the slickline stuffing box **300**, as at **836**. More particularly, the conversion housing **400** may be positioned at least partially above and/or within the upper body **320**. For example, the conversion housing **400** may have outer threads that are configured to engage with inner threads of the upper housing **320**.

[0093] Positioning (or re-positioning) the valve **370** may also include positioning the entry guide **315** (or another entry guide **415**) at least partially above and/or within the conversion housing **400**, as at **838**. The valve **370** may be secured (e.g., vertically) between the shoulder **405** in the conversion housing **400** and the entry guide **315**, **415**.

[0094] The method **800** may also include performing a second slickline wellbore intervention, as at **840**. The second intervention may be performed using a second (e.g., non-digital) slickline **306** while the valve **370** is in the second position. As mentioned above, the second slickline wellbore intervention may be performed before, simultaneously with, or after the first slickline wellbore intervention.

[0095] Performing the second slickline wellbore intervention may include introducing the fluid into the slickline stuffing box **300** through the port **335**, as at **842**. The fluid may be introduced into the chamber that is defined at least partially by the upper body **320** and the (e.g., shoulder **326** of the) piston **325**. The fluid may have a pressure such that when the fluid is introduced into the chamber, the fluid exerts a downward force on the piston **325** that exceeds an upward force exerted on the piston **325** by the biasing member **330**. As a result, the piston **325** moves downward, which compresses the biasing member **330** and the packer elements **345**. As mentioned above, compressing the packer elements **345** may create a static and/or dynamic seal with the outer surface of the slickline **305** and/or the inner surface of the packer housing **340**. This seal may allow the second slickline wellbore intervention to take place.

[0096] Performing the second slickline wellbore intervention may also include removing the fluid from the slickline stuffing box **300** through the port **335**, as at **844**. For example, after the second slickline wellbore intervention has occurred, the fluid may flow out of the chamber through the port **335**. This may allow the biasing member **330** to push the piston **325** back upward, which decompresses the biasing member **330** and the packer elements **345**.

Convertible Slickline Stuffing Box with Easy Packer Change

[0097] FIGS. **9**A and **9**B illustrate a side view and a cross-sectional side view of another slickline stuffing box **900** in a first configuration where the valve **370** is in a lower portion of the slickline stuffing box **900**, according to an embodiment. The slickline stuffing box **900** may be similar to the slickline stuffing box **300**, and the same reference numbers are used where applicable. For example, the slickline stuffing box **900** may include the sheave wheel assembly **310**, the upper body **320**, the piston **325**, the biasing member **330**, the port **335**, the packer elements **345**, the lower body **355**, the collar **360**, the valve **370**, or a combination thereof.

[0098] In the embodiment shown, the packer housing **340** (see FIGS. **3**A and **3**B) may be omitted, and the packer elements **345** may instead be positioned in the upper body **320**. In addition, the piston **325** and/or the biasing member

330 may be positioned at least partially in the lower body **355**. The port **335** may also be coupled to the lower body **355**. The pressurized fluid may be introduced through the port **335** and into the chamber **336** (e.g., now defined by the lower surface of the shoulder **326** of the piston **325** and the lower body **355**), which may push the piston **325** upward.

[0099] Introducing the pressurized fluid into the chamber **336** may compress the packer elements **345** to form a seal around the slickline **305** during a slickline wellbore intervention. As may be seen, the biasing member **330** may be positioned above the shoulder **326** of the piston **325** and configured to exert an increasing axial (e.g., downward) force on the piston **325** as the piston **325** moves upward. After the slickline wellbore intervention, the pressurized fluid may flow back out of the port **335**, and the biasing member **330** may push the piston **325** back downward, allowing the packer elements **345** to decompress.

[0100] The slickline stuffing box **900** may also include some elements that are not present in the slickline stuffing box **300**. For example, the slickline stuffing box **900** may include a second port **337** that is configured to introduce a liquid into a second chamber **338**. In the embodiment shown, the second port **337** is coupled to the lower body **355**, and the second chamber **338** is below the piston **325** and/or the first chamber **336**. In another embodiment, the second port **337** may instead be coupled to the upper body **320**, and the second chamber **338** may be positioned above the piston **325** and/or the first chamber **336**. In this embodiment, the liquid may be introduced to contact the packer elements **345**. The liquid may include one or more chemicals (e.g., glycol, anti-freeze, lubricant). The second chamber **338** may also or instead receive an absorbent packer (e.g., a felt packer) that can soak in lubricant and continue to lubricate the slickline **305** or **306** as it passes therethrough.

[0101] The slickline stuffing box **900** may also include a packer bushing **905**. The packer bushing **905** may be positioned at least partially above and/or within the upper body **320**. For example, the packer bushing **905** may include outer threads that are configured to engage inner threads on the upper body **320**. The packer bushing **905** may also be positioned above (e.g., in direct contact with) the packer elements **345**. When torqued, the packer bushing **905** may exert a downward force onto the packer elements **345**, which compresses the packer elements **345**.

[0102] The slickline stuffing box **900** may also include a packer cap nut **910**. The packer cap nut **910** may be positioned at least partially above and/or within the upper body **320**. The packer cap nut **910** may also be positioned at least partially around the packer bushing **905**. The packer cap nut **910** may include outer threads that are configured to engage inner threads on the upper body **320**. The packer cap nut **910** may secure the packer bushing **905** (e.g., axially) between the packer cap nut **910** and the upper body **320**. For example, the packer cap nut **910** may be torqued to compress the packer elements **345** without using hydraulic pressure.

[0103] The slickline stuffing box **900** may also include a sheave bracket nut **915**. The sheave bracket nut **915** may be positioned at least partially around the packer bushing **905**, the packer cap nut **910**, the upper body **320**, or a combination thereof. For example, the sheave bracket nut **915** may include inner threads that are configured to engage outer threads on the upper body **320**. The sheave bracket nut **915** may secure the sheave bracket **312** on/around the upper body **320**.

[0104] FIG. **10**A illustrates a cross-sectional side view of a conversion housing **1000** that is configured to be positioned at least partially in and/or coupled to the slickline stuffing box **900**, according to an embodiment. FIG. **10**B illustrates a cross-sectional side view of the conversion housing **1000** with the valve **370** positioned therein, according to an embodiment. As with the conversion housing **400**, the conversion housing **1000** may be installed/used to move the valve **370** from the lower portion of the slickline stuffing box **900** to the upper portion of the slickline stuffing box **900** (e.g., to perform a slickline wellbore intervention using the digital slickline **306**).

[0105] The conversion housing **1000** may include or define a lower shoulder **1005**, and the valve **370** may be configured to sit on the shoulder **1005**. The conversion housing **1000** may include a retainer bushing **1010**. The retainer bushing **1010** is configured to be positioned at least partially within the conversion housing **1000**. The valve **370** may be secured (e.g., axially) between the lower shoulder **1005** and the retainer bushing **1010**. An axial bore **1011** may extend (e.g., vertically) through the retainer bushing **1010**. The (e.g., digital) slickline **306** may extend through the bore **1011**. The retainer bushing **1010** may also include or define a downward-facing seat **1020** that is configured to receive the ball **372** when the wellbore pressure pushes the ball **372** upward. The ball **372** may form a seal against the seat **1020** to control/contain the wellbore pressure therebelow.

[0106] The conversion housing **1000** may also include a cap **1025**. The cap **1025** may be positioned at least partially within and/or above the conversion housing **1000**. The cap **1025** may also be positioned at least partially around and/or above the retainer bushing **1010**. The cap **1025** may include outer threads that are configured to engage with inner threads on the conversion housing **1000**.

[0107] The conversion housing **1000** may also include a packer bushing **1030**. The packer bushing **1030** may be the same as, or different from the packer bushing **905** in FIG. **9**B. The packer bushing **1030** may be positioned below the conversion housing **1000**. The packer bushing **1030** may also be positioned above (e.g., in direct contact with) the packer elements **345**. When torqued, the packer bushing **1030** may exert a downward force onto the packer elements **345**, which compresses the packer elements **345**.

[0108] The conversion housing **1000** may also include one or more seals (two are shown: **1035**A, **1035**B) and one or more backup rings (two are shown **1040**A, **1040**B). The seals **1035**A, **1035**B may be or include elastomeric O-rings. The first seal **1035**A and/or the first backup ring **1040**A may be positioned at least partially around (e.g., in a recess in) the retainer bushing **1010**. The second seal **1035**B and/or the second backup ring **1040**B may be positioned at least partially around (e.g., in a recess in) the conversion housing **1000**. For example, the second seal **1035**B and/or the second backup ring **1040**B may be positioned vertically between the lower shoulder **1005** and the packer bushing **1030**.

[0109] FIGS. **11**A and **11**B illustrate a side view and a cross-sectional side view of the slickline stuffing box **900** in a second configuration, according to an embodiment. In the second configuration, the valve **370** may be removed from the lower portion of the slickline stuffing box **900** and relocated to an upper portion of the slickline stuffing box **900**. To accomplish this, the packer bushing **905** and/or the packer cap nut **910** may be removed. As described in greater detail below, in one embodiment, once the packer bushing

905 and/or the packer cap nut 910 are removed, the packer elements 345 may be removed and/or replaced.

[0110] In addition, once the packer bushing 905 and/or the packer cap nut 910 are removed, the conversion housing 1000 may be positioned above and/or at least partially within the upper body 320. For example, the conversion housing 1000 may include outer threads that are configured to engage inner threads of the upper body 320.

[0111] The valve 370 may be positioned at least partially within the conversion housing 1000. The retainer bushing 1010 and/or cap 1025 may be positioned above and/or at least partially within the conversion housing 1000. As mentioned above, the valve 370 may be secured (e.g., vertically) between the shoulder 1005 of the conversion housing 1000 and the retainer bushing 1010. Thus, the conversion housing 1000 may allow the valve 370 to be moved/relocated to be above the packer elements 345. The valve 370 may be in this position when the second slickline wellbore intervention is performed (e.g., using the digital slickline 306).

[0112] FIG. 12 illustrates a flowchart of a method 1200 for converting the slickline stuffing box 300 and/or performing a slickline wellbore intervention, according to an embodiment. An illustrative order of the method 1200 is provided below; however, one or more portions of the method 1200 may be performed in a different order, combined, repeated, or omitted.

[0113] The method 1200 may include positioning the valve 370 in a first (e.g., lower) position within the slickline stuffing box 900, as at 1210. This is shown in FIGS. 9A and 9B. The first position may be below the packer elements 345. The first position may also or instead be at least partially within the lower body 355.

[0114] The method 1200 may also include performing a first slickline wellbore intervention, as at 1220. The first slickline wellbore intervention may be performed using a first (e.g., non-digital) slickline 305 while the valve 370 is in the first position.

[0115] Performing the first slickline wellbore intervention may include introducing a fluid into the slickline stuffing box 900 through the port 335, as at 1222. The fluid may be introduced into the chamber 336. The fluid may have a pressure such that when the fluid is introduced into the chamber(s) 336, the fluid exerts an upward force on the piston 325 that exceeds a downward force exerted on the piston 325 by the biasing member 330. As a result, the piston 325 moves upward, which compresses the biasing member 330 and the packer elements 345. As mentioned above, compressing the packer elements 345 may create a static and/or dynamic seal with the outer surface of the slickline 305 and/or the inner surface of the upper body 320. This seal may allow the first slickline wellbore intervention to take place in the wellbore.

[0116] Performing the first slickline wellbore intervention may also include removing the fluid from the slickline stuffing box 300 through the port 335, as at 1224. For example, after the first slickline wellbore intervention has occurred, the fluid may flow out of the chamber 336 through the port 335. This may allow the biasing member 330 to push the piston 325 back downward, which decompresses the biasing member 330 and the packer elements 345.

[0117] The method 1200 may also include replacing the packer elements 345, as at 1230. Replacing the packer elements 345 may include removing the packer bushing 905 and/or packer cap nut 910, as at 1232. Replacing the packer elements 345 may also include removing the (e.g., old and/or worn) packer elements 345 from the slickline stuffing box 900, as at 1234. Replacing the packer elements 345 may also include introducing different (e.g., new) packer elements 345 into the slickline stuffing box 900, as at 1236. For example, the different (e.g., new) packer elements 345 may be positioned in the upper body 320 in the same location that the old packer elements 345 were positioned prior to being removed.

[0118] The packer elements 345 may be replaced without decoupling and/or removing the sheave wheel assembly 310 and/or the sheave wheel bracket 312. In addition, the chamber(s) 336, 338 may not be exposed to atmosphere when the packer elements 345 are removed and/or replaced. As a result, pressure testing the chamber(s) 336, 338 after the packer elements 345 are removed and/or replaced may be omitted.

[0119] The method 1200 may also include (re-)positioning the valve 370 in a second (e.g., upper) position within the slickline stuffing box 900, as at 1240. This is shown in FIGS. 11A and 11B. The second position may be above the (e.g., new/different) packer elements 345. The second position may also or instead be above the upper body 320. In one embodiment, the valve 370 may be (re-)positioned at the same wellbore and/or the same wellsite where the first slickline wellbore intervention occurred. In another embodiment, the valve 370 may be (re-)positioned at a different wellbore and/or a different wellsite than where the first slickline wellbore intervention occurred.

[0120] Positioning (or re-positioning) the valve 370 may also include positioning the packer bushing 1030 at least partially within the slickline stuffing box 900, as at 1242. More particularly, the packer bushing 1030 may be positioned at least partially within the upper body 320. This may occur while the packer bushing 905 and/or packer cap nut 910 are removed.

[0121] Positioning (or re-positioning) the valve 370 may include positioning the valve 370 at least partially within the conversion housing 1000, as at 1244. More particularly, the valve 370 may be removed from the lower body 355 and positioned on and/or above (or otherwise in contact with) the shoulder 1005 in the conversion housing 1000.

[0122] Positioning (or re-positioning) the valve 370 may also include positioning the conversion housing 1000 at least partially above and/or within the slickline stuffing box 900, as at 1246. More particularly, the conversion housing 1000 may be positioned at least partially above and/or within the upper body 320. For example, the conversion housing 1000 may have outer threads that are configured to engage with inner threads of the upper housing 320. The packer bushing 1030 may be positioned (e.g., vertically) between the conversion housing 1000 and the (e.g., new/different) packer elements 345.

[0123] Positioning (or re-positioning) the valve 370 may also include positioning the retainer bushing 1010 and/or cap 1025 at least partially above and/or within the conversion housing 1000, as at 1248. The valve 370 may be secured (e.g., vertically) between the shoulder 1005 in the conversion housing 1000 and the retainer bushing 1010 and/or cap 1025.

[0124] The method 1200 may also include performing a second slickline wellbore intervention, as at 1250. The second intervention may be performed using the second (e.g., non-digital) slickline **306** while the valve **370** is in the second position.

[0125] Performing the second slickline wellbore intervention may include introducing the fluid into the slickline stuffing box **900** through the port **335**, as at **1252**. The fluid may be introduced into the chamber **336**. The fluid may have a pressure such that when the fluid is introduced into the chamber **336**, the fluid exerts an upward force on the piston **325** that exceeds a downward force exerted on the piston **325** by the biasing member **330**. As a result, the piston **325** moves upward, which compresses the biasing member **330** and the packer elements **345**. As mentioned above, compressing the packer elements **345** may create a static and/or dynamic seal with the outer surface of the slickline **305** and/or the inner surface of the upper body **320**. This seal may allow the second slickline wellbore intervention to take place.

[0126] Performing the second slickline wellbore intervention may also include removing the fluid from the slickline stuffing box **900** through the port **335**, as at **1254**. For example, after the second slickline wellbore intervention has occurred, the fluid may flow out of the chamber(s) **336**, **338** through the ports **335**, **337**. This may allow the biasing member **330** to push the piston **325** back downward, which decompresses the biasing member **330** and the packer elements **345**.

[0127] The foregoing description, for purpose of explanation, has been described with reference to specific embodiments. However, the illustrative discussions above are not intended to be exhaustive or to limit the disclosure to the precise forms disclosed. Many modifications and variations are possible in view of the above teachings. Moreover, the order in which the elements of the methods described herein are illustrate and described may be re-arranged, and/or two or more elements may occur simultaneously. The embodiments were chosen and described in order to explain at least some of the principals of the disclosure and their practical applications, to thereby enable others skilled in the art to utilize the disclosed methods and systems and various embodiments with various modifications as are suited to the particular use contemplated.

1. A slickline stuffing box, comprising:

a piston configured to move in response to a force exerted thereon by a pressurized fluid;

a packer element positioned above the piston, wherein the packer element is configured to compress axially and expand radially, in response to movement of the piston, to seal around a slickline to contain a pressure within a wellbore during a slickline wellbore intervention;

a valve configured to be positioned below the packer element in a first configuration of the slickline stuffing box and above the packer element in a second configuration of the slickline stuffing box, wherein the valve is configured to contain the pressure within the wellbore in response to the slickline breaking and falling down and out of the slickline stuffing box;

a housing that is configured to be positioned above the packer element when the slickline stuffing box is in the second configuration, wherein the valve is configured to be positioned within the housing when the slickline stuffing box is in the second configuration; and

a retainer bushing that is configured to be positioned at least partially within the housing when the slickline stuffing box is in the second configuration, wherein the valve is positioned vertically between the retainer bushing and an inner shoulder of the housing.

2. (canceled)

3. The slickline stuffing box of claim **1**, wherein the valve is not positioned within the housing when the slickline stuffing box is in the first configuration.

4. (canceled)

5. The slickline stuffing box of claim **1**, wherein the retainer bushing defines a downward-facing seat, and wherein the valve comprises a ball that is configured to seal with the seat to contain the pressure within the wellbore in response to the slickline breaking and falling down and out of the slickline stuffing box.

6. The slickline stuffing box of claim **1**, further comprising a cap that is configured to be positioned at least partially within the housing and around at least a portion of the retainer bushing, wherein the cap comprises outer threads that are configured to engage with inner threads of the housing.

7. The slickline stuffing box of claim **1**, further comprising a packer bushing that is configured to be positioned at least partially between the housing and the packer element.

8. The slickline stuffing box of claim **1**, wherein the slickline stuffing box in the first configuration is configured to have a first slickline extend therethrough and to seal around the first slickline to contain the pressure within the wellbore therebelow during a first slickline wellbore intervention, and wherein the slickline stuffing box in the second configuration is configured to have a second slickline extend therethrough and to seal around the second slickline to contain the pressure within the wellbore therebelow during a second slickline wellbore intervention.

9. The slickline stuffing box of claim **8**, wherein the first slickline comprises a non-digital slickline, and wherein the second slickline comprises a digital slickline.

10. The slickline stuffing box of claim **8**, wherein the first slickline wellbore intervention differs from the second slickline wellbore intervention.

11. A slickline stuffing box, comprising:

a housing defining an inner shoulder;

a ball check valve (BCV) configured to be positioned at least partially within the housing, wherein the BCV comprises a ball;

a retainer bushing configured to be positioned at least partially within the housing, wherein the BCV is configured to be positioned vertically between the retainer bushing and the inner shoulder of the housing, wherein a lower surface of the retainer bushing defines a downward-facing seat, and wherein the ball is configured to seal with the seat to contain a pressure within a wellbore in response to a slickline breaking and falling down and out of the slickline stuffing box;

a cap configured to be positioned at least partially within the housing and at least partially around the retainer bushing;

an upper body coupled to and positioned at least partially below the housing, wherein the housing is positioned at least partially within the upper body;

one or more packer elements positioned at least partially within the upper body;

a lower body coupled to and positioned at least partially below the upper body;

a piston positioned at least partially within the lower body;

a biasing member positioned at least partially within the lower body; and

a port coupled to the lower body, wherein the port provides a path of fluid communication between an exterior of the lower body and a chamber within the lower body, wherein the piston moves and compresses the biasing member and the one or more packer elements in response to a fluid flowing into the chamber, and wherein the one or more packer elements expand radially in response to being compressed, which causes the one or more packer elements to seal around the slickline to contain the pressure within the wellbore during a slickline wellbore intervention.

12. The slickline stuffing box of claim **11**, wherein the BCV is configured to be positioned at least partially within the lower body in a first configuration of the slickline stuffing box, and wherein the BCV is configured to be positioned at least partially within the housing in a second configuration of the slickline stuffing box.

13. The slickline stuffing box of claim **11**, further comprising a second port coupled to the lower body, wherein the second port provides a path of fluid communication between the exterior of the lower body and a second chamber within the lower body, wherein the second chamber is below the piston, and wherein a chemical or lubricant is positioned in the second chamber.

14. The slickline stuffing box of claim **11**, further comprising a second port coupled to the upper body, wherein the second port provides a path of fluid communication between the exterior of the lower body and a second chamber within the upper body, wherein the second chamber is above the piston, and wherein a chemical or lubricant is positioned in the second chamber.

15. The slickline stuffing box of claim **11**, wherein the cap comprises a packer cap nut that is configured to be torqued to compress the packer elements.

16. A method, comprising:

removing a first packer bushing from a slickline stuffing box;

removing a first packer element from the slickline stuffing box while the first packer bushing is removed without decoupling a sheave wheel assembly from the slickline stuffing box;

introducing a second packer element into the slickline stuffing box while the first packer bushing is removed and after the first packer element is removed; and

repositioning a valve from a first position within the slickline stuffing box to a second position within the slickline stuffing box, wherein the valve in the first position is below the second packer element in the slickline stuffing box, wherein the valve in the second position is above the second packer element in the slickline stuffing box, and wherein the repositioning comprises:

positioning a second packer bushing in the slickline stuffing box;

positioning the valve within a housing;

positioning a retainer bushing at least partially within the housing, wherein the valve is positioned between the retainer bushing and an inner shoulder of the housing; and

positioning the housing at least partially within the slickline stuffing box, wherein the second packer bushing is positioned within the housing and the second packer element.

17. The method of claim **16**, wherein the first packer element is removed and the second packer element is introduced without exposing a chamber in the slickline stuffing box to atmosphere such that pressure testing of the chamber is omitted in response to introducing the second packer element, and wherein the chamber is positioned below the first packer element, the second packer element, or both.

18. (canceled)

19. (canceled)

20. The method of claim **16**, further comprising:

performing a first slickline wellbore intervention using a non-digital slickline that extends through the slickline stuffing box while the valve is in the first position; and

performing a second slickline wellbore intervention using a digital slickline that extends through the slickline stuffing box while the valve is in the second position.

* * * * *