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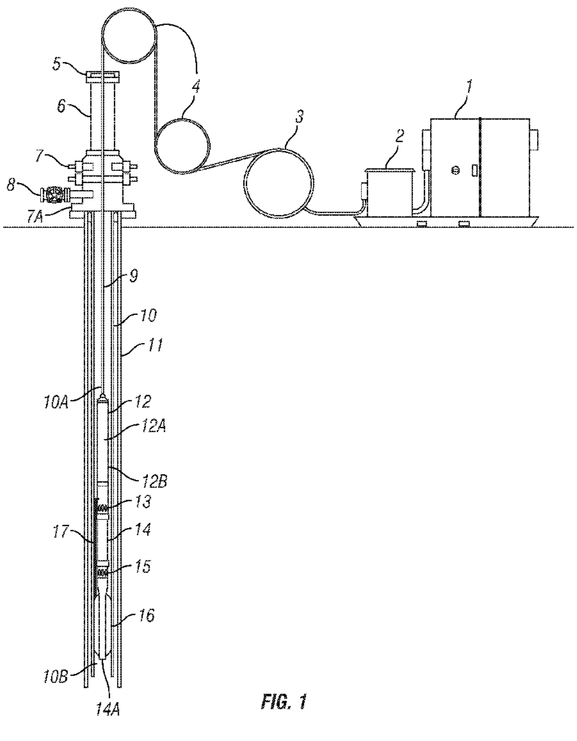

FIG. 1

(57) Abstract: An apparatus for deploying a pump system includes an inflatable annular seal (16) disposed on an exterior of a pump system housing. The annular seal defines a first flow path (10A) and a second flow path (10B) in a wellbore tubular when the annular seal is inflated. A pump (14) has a fluid inlet (14A) disposed in the first flow path when the annular seal is inflated and a fluid outlet (14B) disposed in the second flow path. A valve (60) is operable to direct discharge from the pump into an inflation line (17) fluidly coupled to the annular seal (16) when the valve (60) is in a first position or to surface when the valve is in a second position. The valve is operable between the first and second positions by applying and releasing upward tension on the pump housing or applying fluid pressure to the valve.

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APPARATUS AND METHOD FOR DEPLOYING A PUMP SYSTEM IN A WELLBORE

FIELD

Some examples relate to an apparatus and method for deploying a pump system in a wellbore.

BACKGROUND

This disclosure is related to the field of electrically operated submersible well pumps (ESPs) deployed under live well conditions. More specifically, the disclosure relates to accessories that can be used with such ESP systems to enable setting and unsetting of an inflatable packer mechanism to hydraulically isolate the discharge of the pump from the intake.

U.S. Patent No. 10,036,210 issued to Maclean et al. discloses a method for deploying a pump (e.g., ESP) system in a wellbore. The disclosed method includes coupling the pump system to one end of a tubing encapsulated cable. The cable is extended into a wellbore drilled through a subsurface fluid producing formation. The tubing encapsulated cable has an outer tube extending substantially continuously from the end thereof connected to the pump system to a surface end of the cable. The outer tube is made from material selected to exclude fluid in the wellbore from an interior of the outer tube. The cable includes at least one electrical conductor disposed inside the outer tube, wherein a rated load current of the at least one electrical conductor is selected such that substantially continuous electrical current drawn by the electrical load device exceeds the rated current of the at least one electrical conductor.

When using methods such as those disclosed in the ‘210 patent, it may be desirable to use an inflatable annular seal (packer) to hydraulically close an annular space between the ESP and the wellbore tubular in which the ESP is ultimately disposed, e.g., production tubing or wellbore casing. To use inflatable annular seals with deployment systems known in the art would require the use of an additional deployment cable or tubing and apparatus to inflate and deflate the inflatable annular seal. It is desirable to have apparatus to enable operation of such inflatable annular seals that can be deployed with the ESP system on a tubing encapsulated cable.

SUMMARY

One aspect of the present disclosure is related to an apparatus for deploying a pump system in a wellbore tubular. An apparatus according to such aspect comprises an inflatable annular seal disposed on an exterior of a pump system housing. The inflatable annular seal defines a first flow path and a second flow path in a wellbore tubular when the inflatable annular seal is inflated. A pump is disposed within the pump system housing. The pump has a fluid inlet disposed in the first flow path when the inflatable annular seal is inflated. A fluid outlet of the pump is disposed in the second flow path when the inflatable annular seal is inflated. A first valve is operable to direct discharge from the pump into an inflation line when the first valve is in an inflated position or to surface when the valve is in a pumping position. The first valve is operable by either applying and releasing upward tension on the pump housing or by applying fluid pressure to the first valve.

In some examples, the first valve comprises a sliding sleeve arranged to cover the inflation line when the upward tension and/or fluid pressure is released. In such examples, the sliding sleeve is arranged to close the inflation line and fluidly connect the pump discharge to an interior of the wellbore tubular when the upward tension and/or fluid pressure is applied.

Some examples further comprise a second valve connected to selectively connect the fluid outlet of the pump to the first valve. Communication between the first valve and the second valve may be possible. Communication between the first valve and the second valve may be by means of a piston arrangement.

In some examples, the second valve comprises a latching solenoid operated valve.

Some examples further comprise a biasing arrangement disposed between the pump housing and the sliding sleeve arranged to urge the sliding sleeve to fluidly connect the inflation line to the pump outlet when the upward tension is released. The biasing arrangement may be, for example, a spring or spring arrangement.

In some examples, the pump is reversibly operable such that pumped fluid enters the pump through the fluid discharge and is discharged through the fluid inlet.

In some examples, the pump comprises an electrical submersible pump.

The pump system may comprise a pressure relief arrangement to prevent over-pressurisation of a fluid in the inflatable annular seal. Some examples may further comprise a pressure relief valve operable to vent fluid from the pump discharge into the wellbore when pressure in the inflatable annular seal reaches a predetermined amount.

Some examples may further comprise a pressure sensor in fluid communication with the inflation line. The pressure sensor may be in signal communication with a signal channel extending from the pump system to the surface. The pressure sensor may monitor the discharge pressure of the pump or pump system. The pressure sensor may assist to monitor and/or control the pressure of a fluid in the inflatable annular seal.

The pump system may comprise, or be connected to, a power supply. In some examples, the signal channel may comprise a power cable arranged to transmit electrical power to the pump system from a power supply at the surface.

Another example of the present disclosure relates to a method for deploying and operating a pump in a wellbore. A method according to this example comprises moving a pump system to a selected depth in a wellbore tubular. A pump in the pump system is operated to discharge wellbore fluid into an inflatable annular seal disposed on an exterior of a pump housing in the pump system to inflate the inflatable annular seal. A first valve is operated to redirect discharge from the pump to a fluid flow path extending in the wellbore tubular to the surface, the operating the first valve comprising either applying upward tension to the pump system or applying fluid pressure to the first valve. The pump is operated for a selected time to move wellbore fluids to the surface.

The method may comprise deflating the inflatable annular seal. In some examples, the method may comprise stopping operating the pump, relieving the upward tension on the pump system, deflating the inflatable annular seal and moving the pump system to a different selected depth in the wellbore.

The method may comprise reinflating the inflatable seal. In some examples, the method may further comprise resuming operating the pump to discharge wellbore fluid into the inflatable annular seal to reinflate the inflatable annular seal repeating the operating the first valve to redirect the discharge from the pump to the fluid flow path extending in the wellbore tubular to the surface and repeating the operating the pump for a selected time to move wellbore fluids to the surface.

The method may comprise operating the pump or pump system to deflate the inflatable annular seal. In some examples, the deflating the inflatable annular seal may comprise operating the pump in a reverse direction to withdraw fluid from the inflatable annular seal and discharge the withdrawn fluid into the wellbore tubular.

The method may comprise controlling operation of the pump or pump system in response to a measurement of fluid conditions (e.g. fluid pressure) in the inflatable annular seal. In some examples the method may further comprise measuring fluid pressure in the inflatable annular seal and stopping the operating the pump when the measured pressure reaches a predetermined value.

The method may comprise use of a pressure relief arrangement to prevent over-pressurisation of the inflatable annular seal. In some examples, the method may further comprise venting pressure from the pump discharge to the wellbore tubular when pressure in the inflatable annular seal reaches a predetermined value.

In some examples, the first valve may comprise a sliding sleeve movably coupled to the pump housing and arranged to expose discharge ports in the pump housing to the wellbore tubular when the upward tension is applied to the pump system, the sliding sleeve arranged to close fluid communication between an inflation line extending between the inflatable annular seal and the pump discharge when the upward tension is applied to the pump system housing.

In some examples, the sliding sleeve may be biased to move relative to the pump system housing to close the discharge ports and to open fluid communication between the inflation line and the pump discharge.

In some examples, the wellbore tubular may comprise a wellbore casing or a wellbore production tubing.

Some examples may further comprise simultaneously inflating at least a second inflatable annular seal longitudinally spaced apart from the first annular seal whereby the continuing operating the pump for a selected time causes fluid to be withdrawn from a selected axial interval in the wellbore and moved to the surface.

In some examples, the operating a first valve may comprise operating a second valve arranged to selectively apply fluid pressure to the first valve.

BRIEF DESCRIPTION

FIG. 1 shows an electrical submersible pump system (ESP) deployed in a wellbore using an electrical cable such as a tubing encapsulated cable.

FIG. 2 shows a cross-sectional view of part of the ESP system in FIG. 1 wherein a pump discharge port and sliding sleeve are shown in more detail. The sliding sleeve is in the “inflate/deflate packer” position.

FIG. 3 shows the view of FIG. 2 in more detail wherein the sliding sleeve is in the “inflate/deflate packer” position.

FIG. 4 shows a cross-sectional view of another part of the ESP system shown in FIGS 2 and 3 wherein the sliding sleeve is in the inflate/deflate packer position.

FIGS. 5 and 5A show oblique views of the shuttle and equalizing sub.

FIGS. 6 through 9A show various views of the pump discharge port, shuttle and sliding sleeve apparatus shown in and explained with reference to FIGS. 2, 3 and 4.

FIG. 10 shows another embodiment of a pump system having at least two inflatable annular seals.

FIG. 11 shows another embodiment of an ESP.

FIG. 12 shows a schematic hydraulic diagram for the embodiment shown in FIG. 11.

DETAILED DESCRIPTION

FIG. 1 shows an example of an electrically operated submersible well pump (ESP) system having an inflatable annular seal ("packer") 16 and an inflation/deflation apparatus with a sliding sleeve to enable selective inflation and deflation of the packer. The ESP system may be deployed in a production tubing 10 using an electrical cable 9 (power and deployment cable) such as a tubing encapsulated cable ("TEC"). Deploying the ESP system using a TEC, however, is not a limitation on the scope of the present disclosure. Any other conveyance known to be used for deployment and retrieval of ESP systems in a wellbore may be used to equal effect as TEC, for example and without limitation, armored electrical cable, coiled tubing or jointed tubing. Similarly, the scope of the present disclosure is not limited to deploying an ESP system on or in production tubing. Methods according to the present disclosure may be used within other types of wellbore tubular devices, for example and without limitation, a wellbore casing or a wellbore liner.

The ESP system may comprise a motor such as an electric motor 12. The motor 12 may include a gear section in some embodiments. A rotating output of the electric motor 12 may be coupled through a suitable seal and protector apparatus (protector) 12A to a pump 14, for example a progressive cavity pump or other positive displacement pump, or a centrifugal pump. The pump 14, protector 12A and a valve to be explained in more detail below may be disposed within a pump system housing 12B.

A discharge of the pump 14 may be selectively placed in fluid communication with either a discharge port 13 disposed longitudinally above an inflatable annular seal ("packer") 16 or with an inflation line 17 in fluid communication with an inflation port in the packer 16 using a discharge port and sliding sleeve assembly (sliding sleeve 60 in FIG. 2) to be explained in more detail below. The packer 16 may be inflated to seal an annular space between the pump 14 and an interior wall of the production tubing 10. When the packer 16 is inflated, the packer 16 defines and hydraulically separates a first fluid flow path 10A and a second fluid flow path 10B within the production tubing 10 (or wellbore casing or liner as explained above). An inlet of the pump, shown at 14A, may be disposed in the first flow path 10B. Discharge from the pump 14 directed to the discharge port 13 will be constrained to move upwardly in the production tubing 10 to the surface when the packer 16 is inflated, as will be further explained with reference to FIG. 4. The production tubing 10 in some embodiments may be nested inside a wellbore casing 11 that extends to the surface, or as previously explained, the pump system may be disposed in a different type of wellbore tubular such as wellbore casing (e.g., 11 in FIG. 1, for wellbores in which a production tubing is not used as shown in FIG. 1) or a wellbore liner.

An annular bypass check valve 15 may be disposed along the discharge port and sliding sleeve assembly (60 in FIG. 2) and arranged such that the annular bypass check valve 15 is closed when the pump 14 is operating and opens a sliding sleeve (FIG. 2) disposed in position to enable inflation and deflation of the packer 16. The sliding sleeve will be explained in more detail with reference to FIG. 2.

The wellbore casing 11 and production tubing 13 may terminate in a wellhead 7A. The wellhead 7A may include a pressure control device 7 such as a blowout preventer ("BOP") stack and a wing valve (fluid outlet) 8. For purposes of deploying the ESP system in the production tubing 10 and maintaining pressure control of the wellbore during operation of the ESP system, a lubricator 6 and pack off 5 may be coupled to the wellhead 7A.

The operating components for the ESP system may comprise a variable frequency drive 1 and a transformer 2 disposed at the surface and electrically connected to one or more insulated electrical conductor (not shown) in the deployment cable 9. The deployment cable 9 may be extended into the wellbore and retracted from the wellbore using an intervention winch 3 and sheaves 4 of types well known in the art.

FIG. 2 shows an example embodiment of the discharge port and sliding sleeve assembly 60 coupled to the ESP system (FIG. 1) in more detail. In FIG. 2, the discharge port and sliding sleeve assembly 60 is in a first or "inflate packer/deflate packer" position.

The discharge port and sliding sleeve assembly 60 may comprise a discharge port sub 21 having discharge ports 13A in fluid communication with the discharge or outlet of the pump (14 in FIG. 1). The discharge port sub 21 may form part of or be connected to the lower end of the pump (14 in FIG. 1). Discharge from the pump (14 in FIG. 1) may enter the interior of the discharge port sub 21 and the interior of the discharge port and sliding sleeve assembly 60. The discharged flow from the pump (14 in FIG. 1) may be stopped from flow through the discharge ports 13A when the pump (14 in FIG. 1) is operating and the discharge port sleeve 22 is in the position shown in FIG. 2 (i.e., covering the discharge ports 13A). A discharge port sleeve connector 23 may be sealingly engaged with an interior of the discharge port sleeve 22. A sleeve limiter 28 may be provided as a backstop for limiting axial movement of the discharge port sleeve 22 and as a landing surface for a discharge port spring 27 to axially urge the discharge port sleeve 22 to the position shown in FIG. 2 when there is no upward tension on the ESP system from the deployment cable (9 in FIG. 1).

A non-rotating tube 24 may be disposed within a shuttle housing 25. A shuttle tube 29 may be disposed within the shuttle housing 25 and be retained in rotationally fixed position by an anti-rotation pin as will explained with reference to FIG. 4. An equalizing sub 26 may comprise features to be explained in more detail with reference to FIG. 4 such that the inflation line (17 in FIG. 1) is fluidly connected to the interior of the discharge port and sliding sleeve assembly 60. When fluid connection is thus made, discharge from the pump (14 in FIG. 1) is directed to the inflation line (17 in FIG. 1).

The discharge port spring 27 may be disposed in an annular space between the discharge port sub 21 and the port sleeve connector 23. The discharge port spring 27 may urge discharge port sub 21 to remain in the position shown in FIG. 2 until the packer (16 in FIG. 1) is inflated and axial force is applied to the ESP system (FIG. 1) in a direction toward the surface.

The shuttle tube 29 may be disposed within the shuttle housing 25 such that toothed features (explained in more detail with reference to FIG. 4) on one end of the shuttle tube 29 may engaged corresponding toothed features on a shuttle 30. The shuttle 30 may be disposed within the shuttle housing 25. The shuttle 30 may comprise features, explained in more detail with reference to FIG. 4, that selectively open and close flow from the pump (14 in FIG. 1) discharge to the inflate line (17 in FIG. 1). A shuttle spring 31 may urge the shuttle 30 to close flow to the inflation line (17 in FIG. 1) when axial force is applied to the ESP system (FIG. 1).

FIG. 3 shows seals 32, for example chevron style or a “polypak” seal stack slidably engaged on a smooth bore 22A within the discharge port sleeve 22. The position of the discharge port sleeve 22 with respect to the discharge port sub 21 is the same as shown in FIG. 2; the view in FIG. 3 is intended to show how the discharge port sleeve 22 closes fluid flow from the discharge ports 13A when the discharge port sleeve 22 and discharge port and discharge port and sliding sleeve assembly (60 in FIG. 2) is in the first position as explained with reference to FIGS. 2 and 3.

Anti-rotation grub screw features 33, e.g., as may be used for threaded joints, may be used to enable the discharge port sleeve 22 to remain rotationally fixed at a threaded connection once the threaded connection is assembled (made up).

FIG. 4 shows lower toothed features 41 in the shuttle tube 29. The lower toothed features 41 may have equal angles on both tooth faces of each tooth. Upper toothed features 42 may be formed in an opposed longitudinal end of the shuttle 30. The upper toothed features 42 may have non equal angled tooth faces. Fluid ports 43 may be formed in the in shuttle 30 so that the inflate line 17 connected to the packer (16 in FIG. 1) is in fluid communication with the interior of the discharge ports within the discharge port and sliding sleeve assembly (60 in FIG. 2) is in the inflate/deflate packer position as shown in FIG. 2. The shuttle 30 may comprise chevron style or Polypak seal stacks 45 to enable the shuttle 30 to slide on and remain sealingly engaged with a smooth bore 26A on an interior surface of the equalizing sub 26.

FIG. 5 shows an oblique view of the equalizing sub 26 including a fluid port 51 to enable fluid from the pump (14 in FIG. 1) to move into the packer (16 in FIG. 1) through the inflate line (17 in FIG. 1 and FIG. 4) when the discharge port and sliding sleeve assembly (60 in FIG. 2) is in the position shown in FIGS. 2 and 3. One or more slots 52 may be formed in the shuttle housing 25 such that an anti-rotation pin 53 slides in each of the one or more slots 52. FIG. 5A shows the shuttle 30 in the “inflate/deflate packer” position.

FIGS. 6 through 9A show the same views as FIGS. 2 through 5A, respectively, wherein the discharge port and sliding sleeve assembly (60 in FIG. 2 and 6) is in a second or “discharge port open” position. When the discharge port and sliding sleeve assembly (60 in FIG. 2 and 6) is in the discharge port open position, the discharge ports (13A in FIGS. 2 and 6) are exposed to the interior of the production tubing (10 in FIG. 1) and the fluid ports (43 in FIGS. 4 and 8) are closed. Thus all of the discharge from the pump (14 in FIG. 1) is constrained to flow in the production tubing (10 in FIG. 1) toward the surface. The discharge fluid is also constrained to flow upward toward the surface because the annular space between the intake of the pump is sealed against the wellbore.

A pressure sensor (not shown in the figures) may be provided to measure fluid pressure in the packer (16 in FIG. 1) inflation chamber, pump discharge pressure and/or pump intake pressure. Such measurements may be transmitted to surface over the deployment cable (9 in FIG. 1) or any other suitable signal channel in signal communication with the pressure sensor, and such measurements may be used as will be explained further below.

Operating the system explained with reference to FIGS. 1 through 9A may comprise some or all of the following actions in their respective order. First, the ESP system shown in FIG. 1 may be deployed into a wellbore on the deployment cable (9 in FIG. 1) using the intervention winch (3 in FIG. 1). During deployment of the ESP system, the discharge port and sliding sleeve assembly (60 in FIG. 2) will be in the in packer inflate/deflate position as a result of axial force exerted by the discharge port spring (27 in FIG. 2) and the shuttle spring (31 in FIG. 2).

Once the ESP system is disposed at a selected or predetermined axial position (i.e., measured depth) in the wellbore, the ESP system (i.e., by energizing the motor 12 in FIG. 1), controlling the pump speed using the variable frequency drive (1 in FIG. 1) pumping fluid from the wellbore into the inflation line (17 in FIG. 1), the flow being stopped from existing the discharge ports (13A in FIG. 2) by reason of the sliding sleeve (22 in FIG. 2) closing the discharge ports (13A in FIG. 2) and opening the ports (43 in FIG. 4) to fluid communication with the discharge line (17 in FIG. 4).

When a predetermined pressure in the packer (16 in FIG. 1) is reached, a pressure relief valve (not shown) may limit pressure in the packer (16 in FIG. 1) to the predetermined pressure. Such condition may be determined when measured pressure stops increasing. The ESP system may then be switched off. At such time, the ESP system will be held in place longitudinally by the packer (16 in FIG. 1).

Tension may then be applied to the deployment cable (9 in FIG. 1) that exceeds the total deployment cable and ESP system weight in the well by a predetermined amount. The axial force causes the ESP system and the discharge port sub (21 in FIG. 2) to move axially with respect to the discharge port and sliding sleeve assembly (60 in FIG. 2) to open the discharge ports (13A in FIG. 6 and 7) and close the inflation line (17 in FIG. 8) to discharge from the pump (14 in FIG. 1).

The tension is held on the deployment cable for the duration of time that the discharge ports (13A in FIG. 6 and 7) are intended to be open. The ESP system may then be switched on and the pump speed may be adjusted to pump well fluids to surface through the production tubing (10 in FIG. 1). When such fluid pumping is no longer required the ESP system may be switched off. Tension on the deployment cable (9 in FIG. 1) may then be reduced. As a result of reducing the tension, the discharge port and sliding sleeve assembly (60 in FIG. 2) may return to the position shown in and explained with reference to FIGS. 2 through 5A. In such position, the discharge ports (13A in FIG. 2) are closed by the sliding sleeve (22 in FIG. 2) and the inflation line (17 in FIG. 4) is fluidly connected to the interior of the discharge port and sliding sleeve assembly (60 in FIG. 2). Pressure in the packer may be bled to the wellbore through the pump (14 in FIG. 1).

The packer (16 in FIG. 1) may be allowed to relax over a predetermined time period. The ESP system may be moved in wellbore to a new axial position (measured depth) or removed from the wellbore. The foregoing procedure or relevant parts thereof may be repeated as required. The foregoing sequence of actions is summarized in TABLE 1 below.

TABLE 1

Step	**Pin Position**	**Discharge Port Status**	**Inflation Line Status**	**Pump Motor Status**	**Cable Status**
Run ESP in well to selected depth	1 Moving	CLOSED	OPEN	OFF	In tension RIH forces, spooling cable into well
Inflate packer	2 Inflate	CLOSED	OPEN	ON	Cable held at required depth
Open discharge Ports	3 Pumping	OPEN	CLOSED, Pressure locked in	ON	Release tension, apply tension to cable (spring force).
Deflate Packer	4 Deflate	CLOSED	OPEN	OFF	Release tension, hold position to allow packer to relax, tension will increase by reason of ESP system weight
Pull out of well or/ move ESP to new depth	1 Moving	CLOSED	OPEN	OFF	In tension, pulling force to spool cable out of wellbore or to different depth.

In some embodiments, and referring to FIG. 10, a part of the pump system housing comprising the pump inlet 14A may be extended longitudinally beyond (below) the packer 16. At least a second packer 16A similar to the inflatable packer 16 may be disposed on the exterior of the extended pump system housing such that the pump inlet 14A is disposed longitudinally between the packers. The second packer 16A may also be an inflatable packer 16A, and have an straddle inflation/deflation line 60 fluidly coupled to the inflation line 17 as described with reference to FIG. 1. Thus, when the pump system is operated to direct pump discharge to the inflation line 17 in FIG., both packers 16, 16A will inflate, and conversely, the deflation procedure described above will result in deflation both packers 16, 16A. By having two longitudinally spaced apart packers16, 16A, the pump system described herein may be positioned in a wellbore to isolate the pump inlet 14A both above and below. So isolated, the pump inlet 14A may move fluid from a specific, isolated zone 62 within the wellbore. In this way, one or more selected axial intervals or zones in the wellbore may be tested. Other aspects of the deployment, pumping and release of the pump system may be substantially as explained above. Other embodiments may comprise more than the second packer 16A by extending the pump system housing longitudinally further and disposing additional packers in a similar manner on the extended pump system housing.

In some embodiments, and referring to FIG. 11, the ESP may comprise a signal communication sub 102 having circuitry therein to detect a control signal that may be generated by suitable control circuits (not shown separately) in the variable frequency drive (1 in FIG. 1). Such control signal when detected may be used to generate an operating signal to be transmitted over a control line 104 to a valve 100. The valve may be a solenoid operated valve and may be hydraulically connected to selectively direct discharge from the pump 14 to either the sliding sleeve (60 in FIG. 12) or to the well (e.g., to 10A in FIG. 1). Example embodiments of a solenoid operated valve may be obtained from TLX Technologies, N27 W23727 Paul Road, Pewaukee, Wisconsin 53072.

In operation, the embodiment shown in FIG. 11 may act as follows. A command is sent from the surface, for example by modulating the voltage transmitted along the cable 9. Such signal may be detected in the signal communication sub 102. The command can include error checking to prevent unintended operation of the valve 100.

On receipt of a suitable command, the signal communication sub 102 may energize the control line 104 to switch the valve 100 state. The signal communication sub 102 may include the circuits required (not shown) to generate and store the required charge which is switched into the valve 100 to change its state.

The sliding sleeve 60 can pass the full flow of the pump 14 (e.g., up to several thousand barrels per day). Pressure from the pump discharge is ported through the valve 100 to move the sliding sleeve 60 between two positions: (i) port the pump discharge to the annular seal; or (ii) port the pump discharge to the well, e.g., to the production tubing (allows well fluids to be pumped to surface). The valve 100 itself is not intended to pass full pump flow. The valve 100 only ports the pump discharge pressure, which through appropriately sized pistons (not shown) will overcome the spring and move the sliding sleeve 60. If the pump discharge pressure is removed then the spring moves the sliding sleeve 60 back to its normal position.

Hydraulic connection of the solenoid valve 100 and sliding sleeve 60 between the pump discharge and the well are shown schematically in FIG. 12. Operation of the valve 100 and the sliding sleeve 60 are described for various actions using the ESP system in TABLE 2. In the present embodiment, the sliding sleeve 60 may be operated by fluid pressure from the pump as shown in FIG. 12 rather than by upward tension on the cable 9.

TABLE 2

Task Performed	**Sliding Sleeve Position**	**Pump Control Line**	**Deflate Control Line**	**Pump Status**	**Action**
Move ESP system Into well	B	-	-	Off	
Inflate seal	B	-	-	On	As Pump discharge pressure builds the packer inflates
Pull tension on cable to verify anchored	B	-	-	Off	Test that the packer has inflated and is anchored by pulling on cable.
Select pump outlet line; pump fluid to surface	A	Switch	-	On	After the solenoid is switched as Pump discharge pressure builds the sliding sleeve moves to position A and Pump discharge is ported to Pump outlet (normal pumping operation).
Finish pumping to surface	B	Switch	-	Off	As pressure is removed the spring moves the sliding sleeve to position B. The solenoid is then switched.
Deflate seal	B	-	Switch	Off	Packer deflates through the solenoid valve
Move ESP system	B	-	Switch	Off	Solenoid is switched back to initial position

Operating the valve 100 may provide for selective operation of the sliding sleeve 60 without the need to apply tension on the cable 9.

In some embodiments, a check valve may be provided to retain pressure in the annular seal after the pump is stopped or after the position of the sliding sleeve 60 is changed. In some embodiments, a pressure sensor (not shown) measurement may be included to measure the pump discharge pressure and could be used to control the inflation pressure for the annular seal. In some embodiments, a bleed valve may be provided to deflate the annular seal. Other configurations could be used, for example to move the sliding sleeve 60 in the opposite direction which may open a bleed line until the annular seal is deflated.

The configuration shown in FIG. 12 may have the advantage of not requiring the valve 100 to switch state while the pump is running, which simplifies the command detection and reduces the likelihood of unintended switching of the valve 100, for example, as may be caused by electrical noise from the motor (12 in FIG. 11).

The 3 position latching solenoid valve shown in FIG. 12 may be substituted by two, 2 position latching solenoid valves. In some embodiments, which can use 1x 2 position latching solenoid valves may be used. A non-limiting example embodiment of the valve 100 may be a solenoid operated, latching valve, for example, one sold under part number SDLA2131033A by The Lee Company, 2 Pettipaug Road, Westbrook, Connecticut 06498-0424.

Although only a few examples have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible in the examples. Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims.

CLAIMS

1. An apparatus for deploying a pump system in a wellbore tubular, comprising:

an inflatable annular seal disposed on an exterior of a pump system housing, the inflatable annular seal defining a first flow path and a second flow path in a wellbore tubular when the inflatable annular seal is inflated;

a pump disposed within the pump system housing, the pump having a fluid inlet disposed in the first flow path, a fluid outlet of the pump disposed in the second flow path; and

a first valve operable to direct discharge from the pump into an inflation line fluidly coupled to the inflatable annular seal when the valve is in a first position or to the surface when the valve is in a second position, the valve operable between the first position and the second position by at least one of (i) applying and releasing upward tension on the pump housing and (ii) applying fluid pressure from the pump to the first valve.

2. The apparatus of claim 1, wherein the first valve comprises a sliding sleeve arranged to cover the inflation line when the upward tension is released, the sliding sleeve arranged to close the inflation line and fluidly connect the pump discharge to an interior of the wellbore tubular when the upward tension is applied.

3. The apparatus of claim 2, further comprising a spring disposed between the pump housing and the sliding sleeve, the spring arranged to urge the sliding sleeve to fluidly connect the inflation line to the pump outlet when the upward tension is released.

4. The apparatus of any preceding claim, further comprising a second valve connected to selectively connect the fluid outlet of the pump to first valve.

5. The apparatus of claim 4, wherein the second valve comprises a latching solenoid operated valve.

6. The apparatus of any preceding claim, wherein the pump is reversibly operable such that pumped fluid enters the pump through the fluid discharge and is discharged through the fluid inlet.

7. The pump system of any preceding claim, wherein the pump comprises an electrically operated, submersible well pump.

8. The pump system of any preceding claim, further comprising a pressure relief valve operable to vent fluid from the pump discharge into the wellbore when pressure in the inflatable annular seal reaches a predetermined amount.

9. The pump system of any preceding claim, further comprising a pressure sensor in fluid communication with the inflation line, the pressure sensor in signal communication with a signal channel extending from the pump system to the surface.

10. The pump system of claim 9, wherein the signal channel comprises a power cable arranged to transmit electrical power to the pump system from a power supply at the surface.

11. A method for deploying and operating a pump in a wellbore, comprising:

moving a pump system to a selected depth in a wellbore tubular;

operating a pump in the pump system to discharge wellbore fluid into a first inflatable annular seal disposed on an exterior of a pump housing in the pump system to inflate the first inflatable annular seal;

operating a first valve to redirect discharge from the pump to a fluid flow path extending in the wellbore tubular to the surface, the operating the valve comprising at least one of (i) applying upward tension to the pump system and (ii) applying fluid pressure to the valve; and continuing operating the pump for a selected time to move wellbore fluids to the surface.

12. The method of claim 11, further comprising:

stopping operating the pump;

relieving the upward tension on the pump system;

deflating the first inflatable annular seal; and

moving the pump system to a different selected depth in the wellbore.

13. The method of claim 12, further comprising:

resuming operating the pump to discharge wellbore fluid into the inflatable annular seal to reinflate the first inflatable annular seal;

repeating the operating the first valve to redirect the discharge from the pump to the fluid flow path extending in the wellbore tubular to the surface; and

repeating the operating the pump for a selected time to move wellbore fluids to the surface.

14. The method of claim 12, wherein the deflating the inflatable annular seal comprises operating the pump in a reverse direction to withdraw fluid from the first inflatable annular seal and discharge the withdrawn fluid into the wellbore tubular.

15. The method of any of claims 11 to 14, further comprising measuring fluid pressure in the first inflatable annular seal and stopping the operating the pump when the measured pressure reaches a predetermined value.

16. The method of any of claims 11 to 15, further comprising venting pressure from the pump discharge to the wellbore tubular when pressure in the first inflatable annular seal reaches a predetermined value.

17. The method of any of claims 11 to 16, wherein the first valve comprises a sliding sleeve movably coupled to the pump housing and arranged to expose discharge ports in the pump housing to the wellbore tubular when the upward tension is applied to the pump system, the sliding sleeve arranged to close fluid communication between an inflation line extending between the first inflatable annular seal and the pump discharge when the upward tension is applied to the pump system housing.

18. The method of claim 17, wherein the sliding sleeve is biased to move relative to the pump system housing to close the discharge ports and to open fluid communication between the inflation line and the pump discharge.

19. The method of any of claims 11 to 18, wherein the wellbore tubular comprises a wellbore casing or a wellbore production tubing.

20. The method of any of claims 11 to 19, further comprising simultaneously inflating at least a second inflatable annular seal longitudinally spaced apart from the first annular seal whereby the continuing operating the pump for a selected time causes fluid to be withdrawn from a selected axial interval in the wellbore and moved to the surface.

21. The method of any of claims 11 to 20, wherein the operating the first valve comprises operating a second valve arranged to selectively connect discharge from the pump to the first valve.

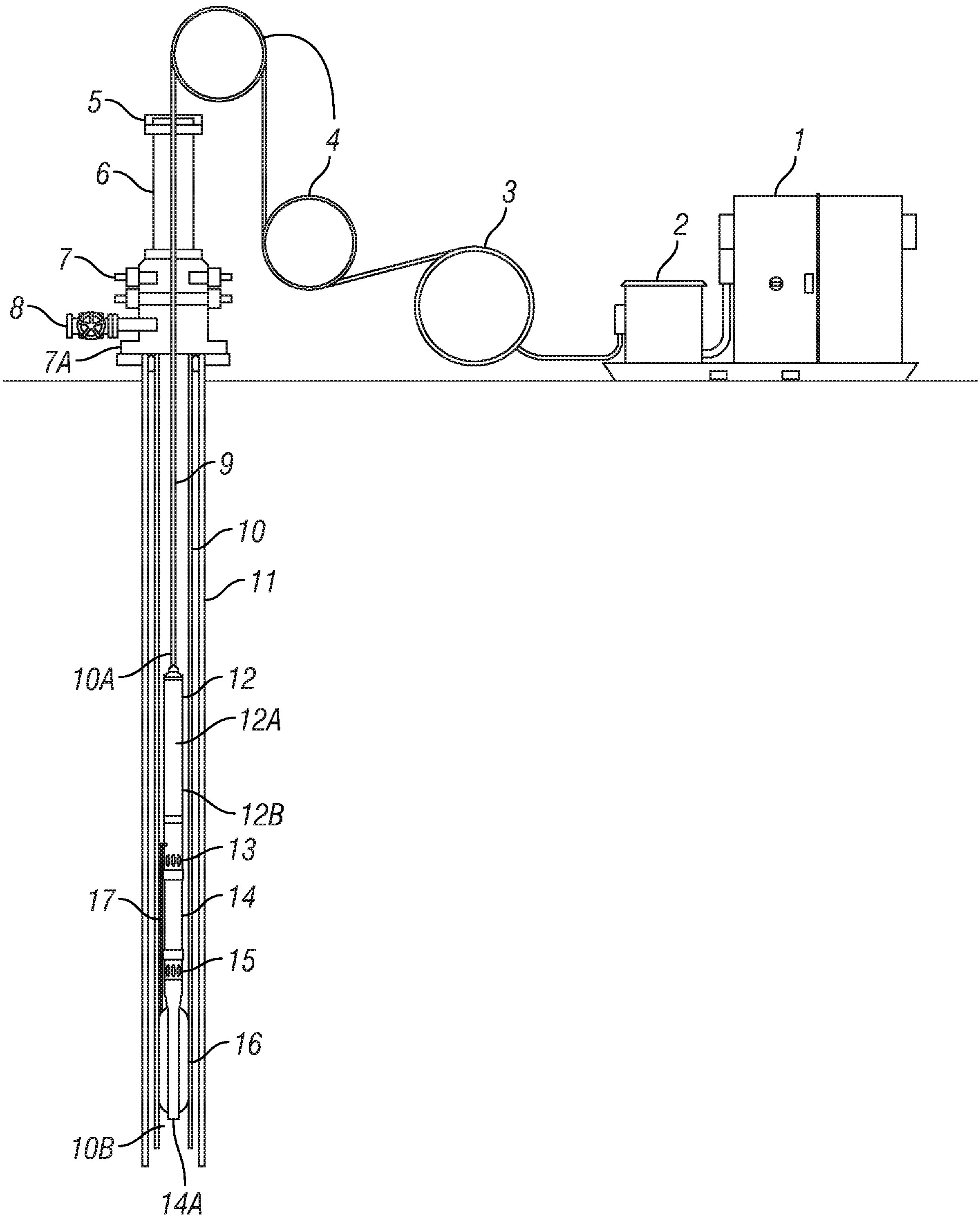


FIG. 1

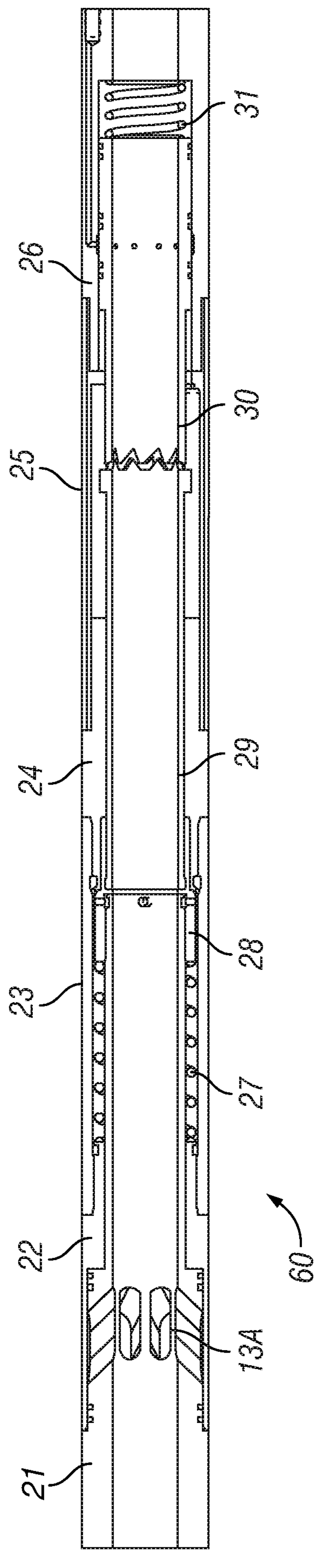


FIG. 2

3/10

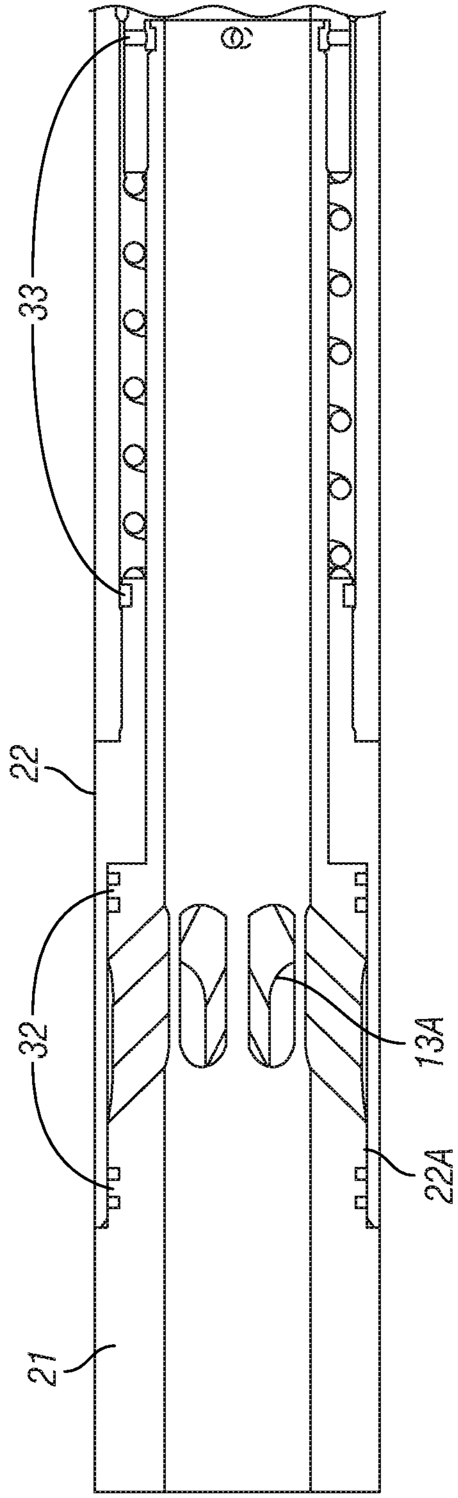


FIG. 3

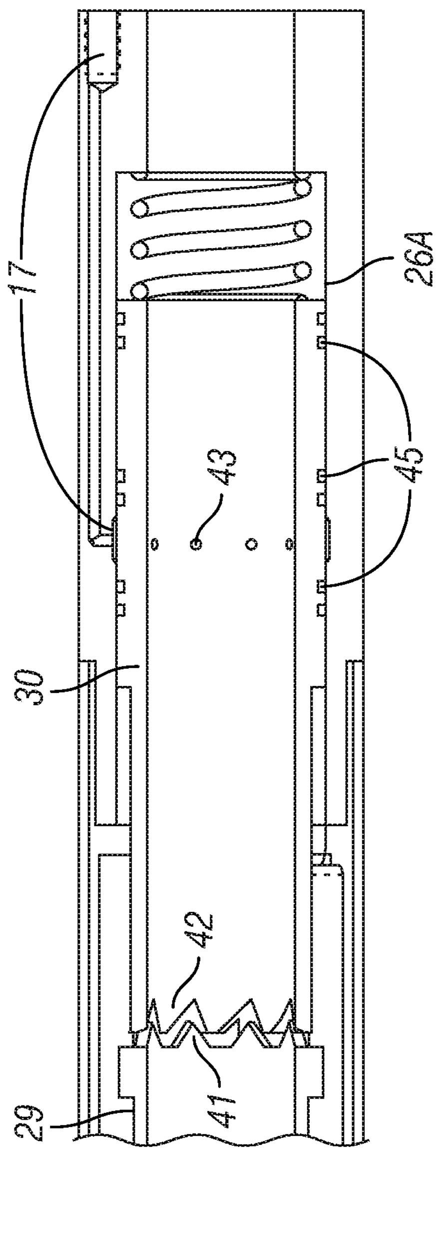


FIG. 4

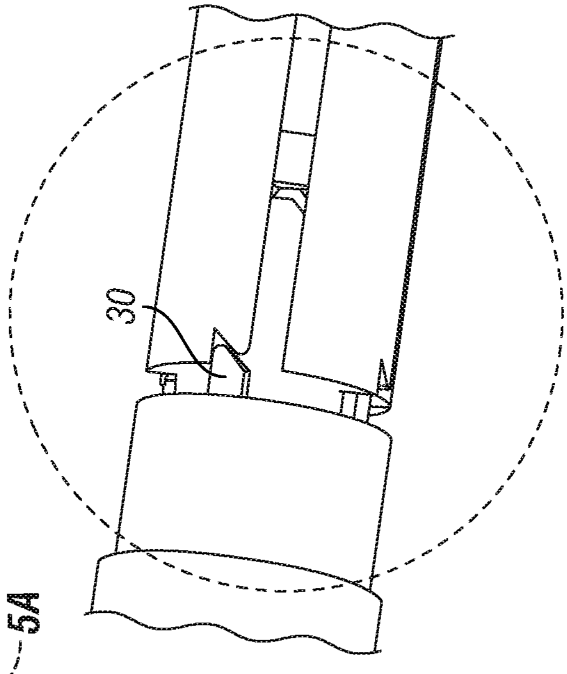
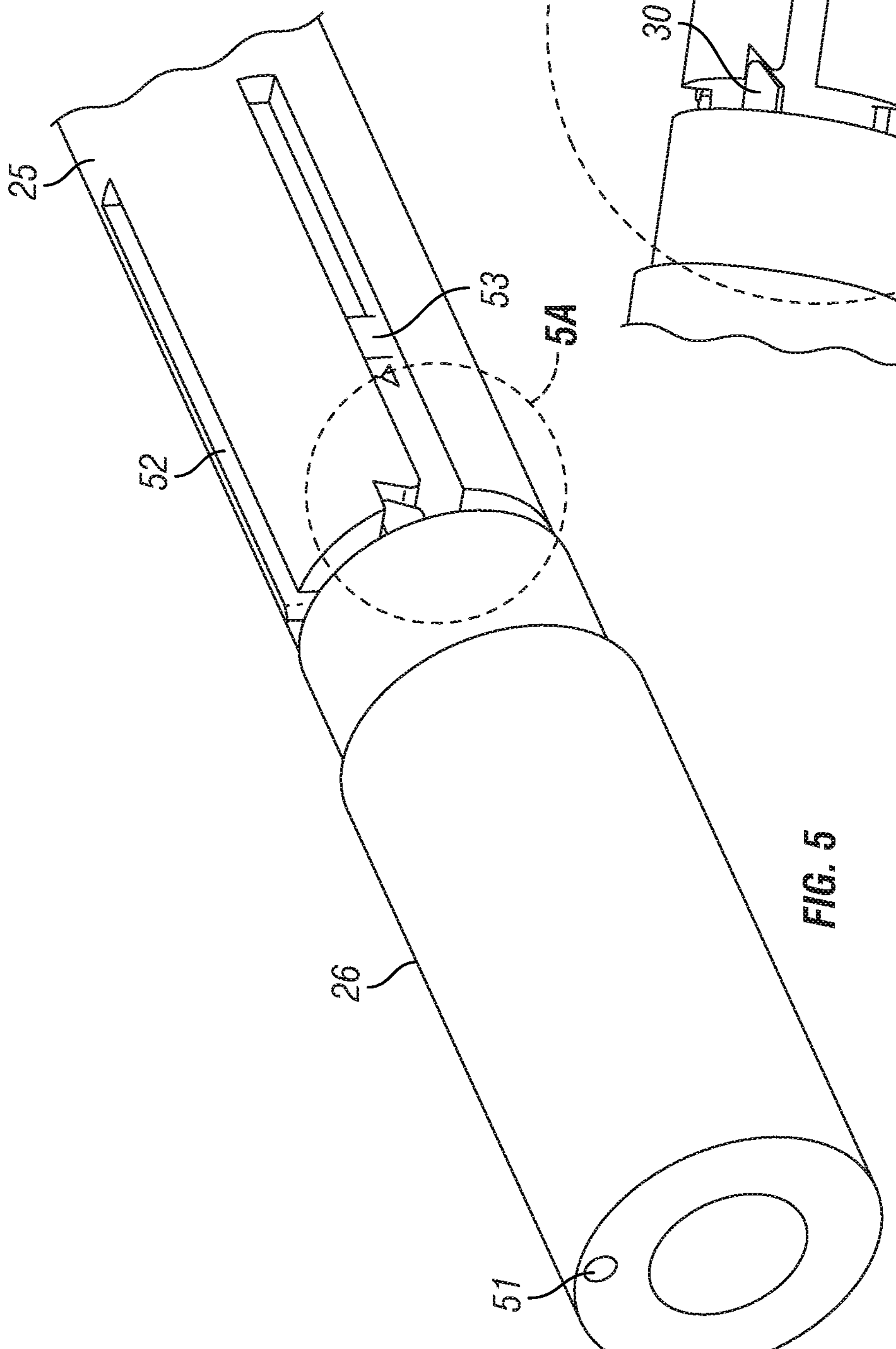


FIG. 5A



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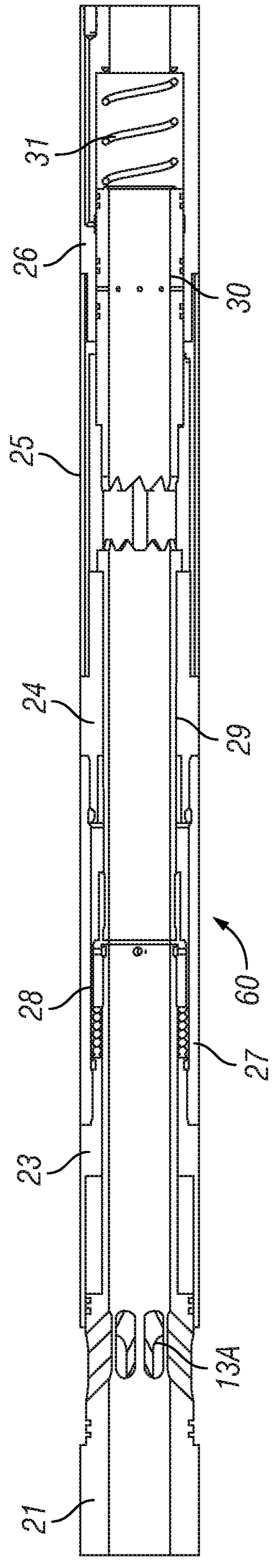


FIG. 6

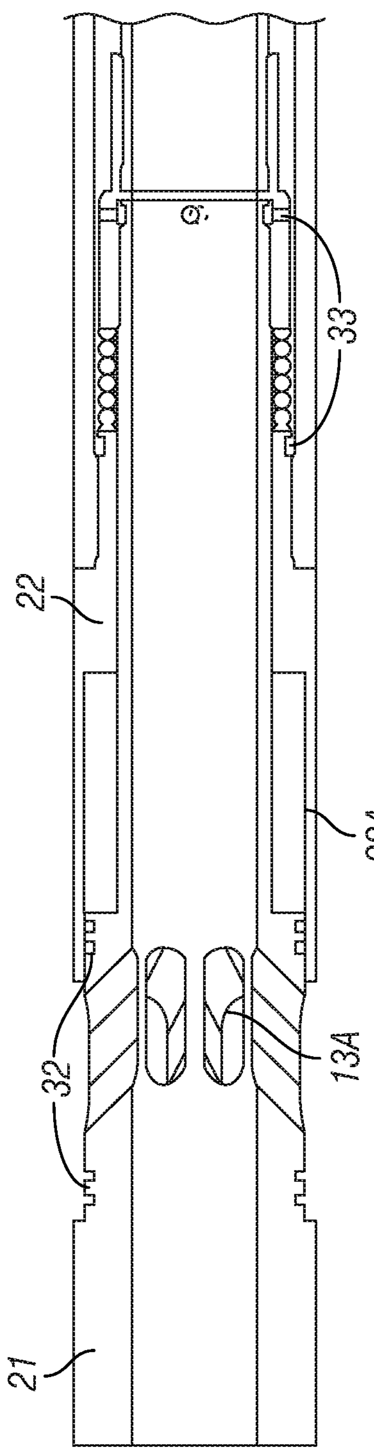


FIG. 7

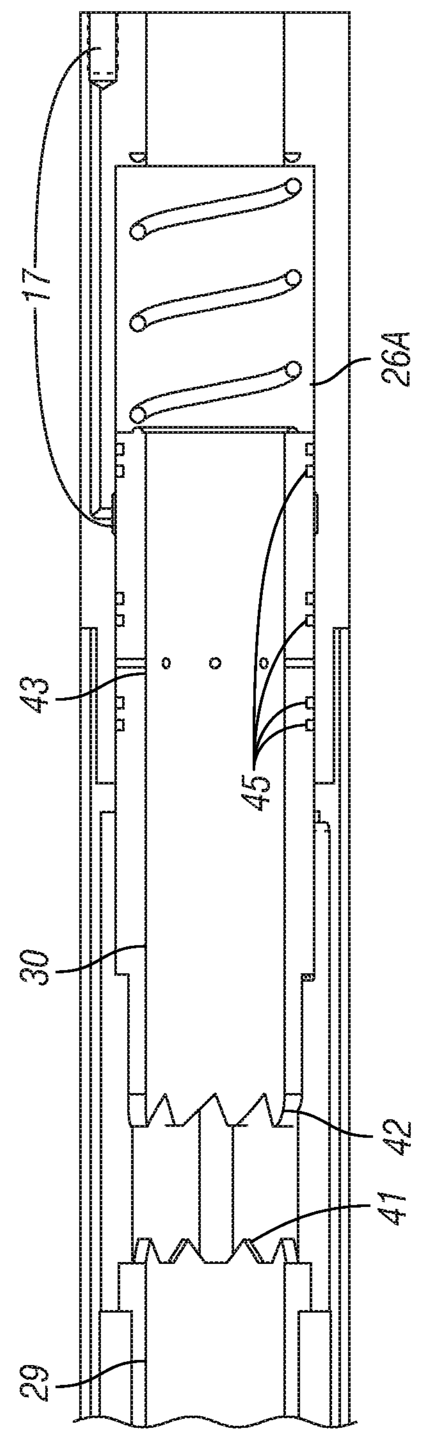


FIG. 8

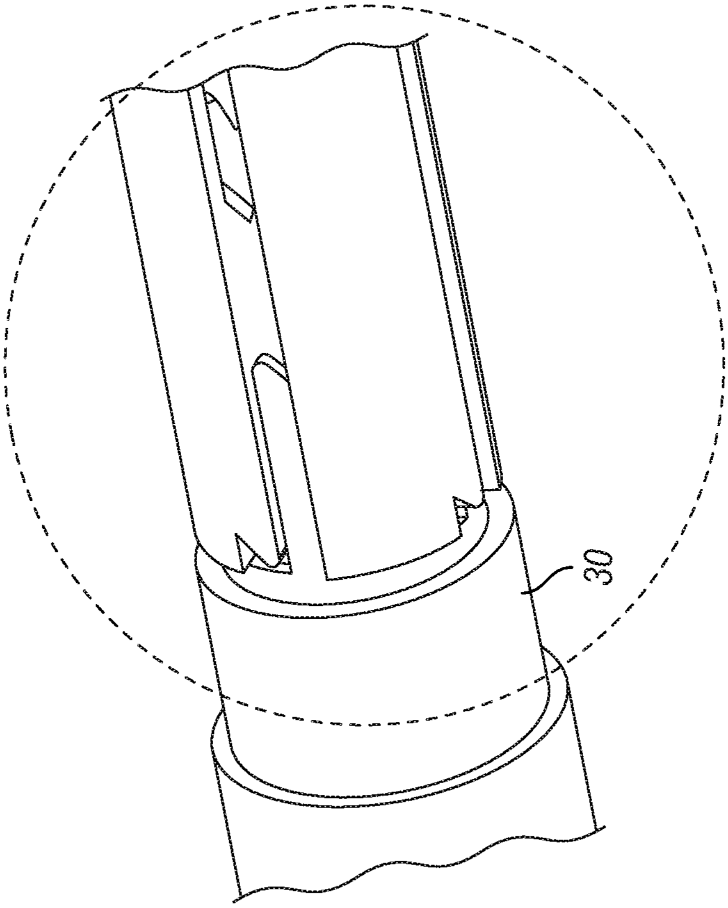


FIG. 9A

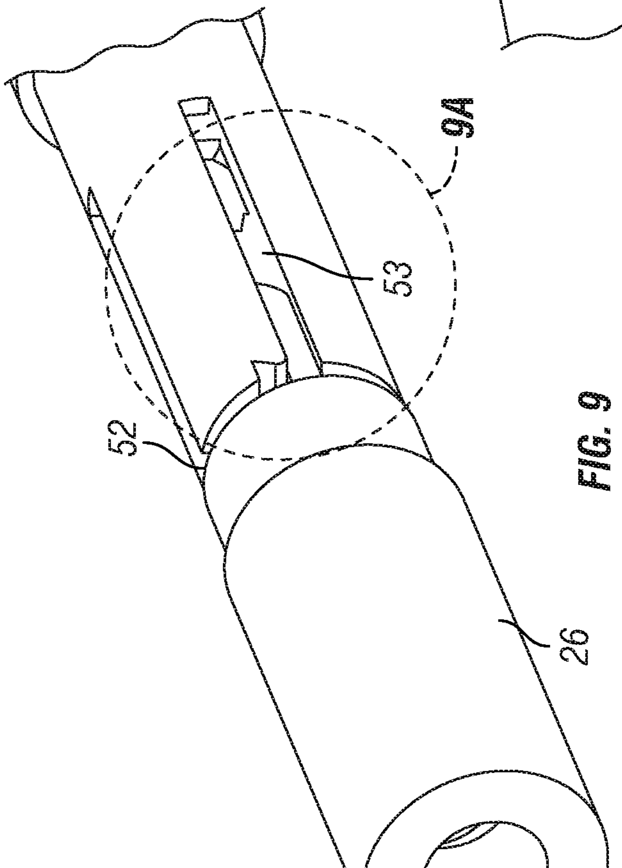


FIG. 9

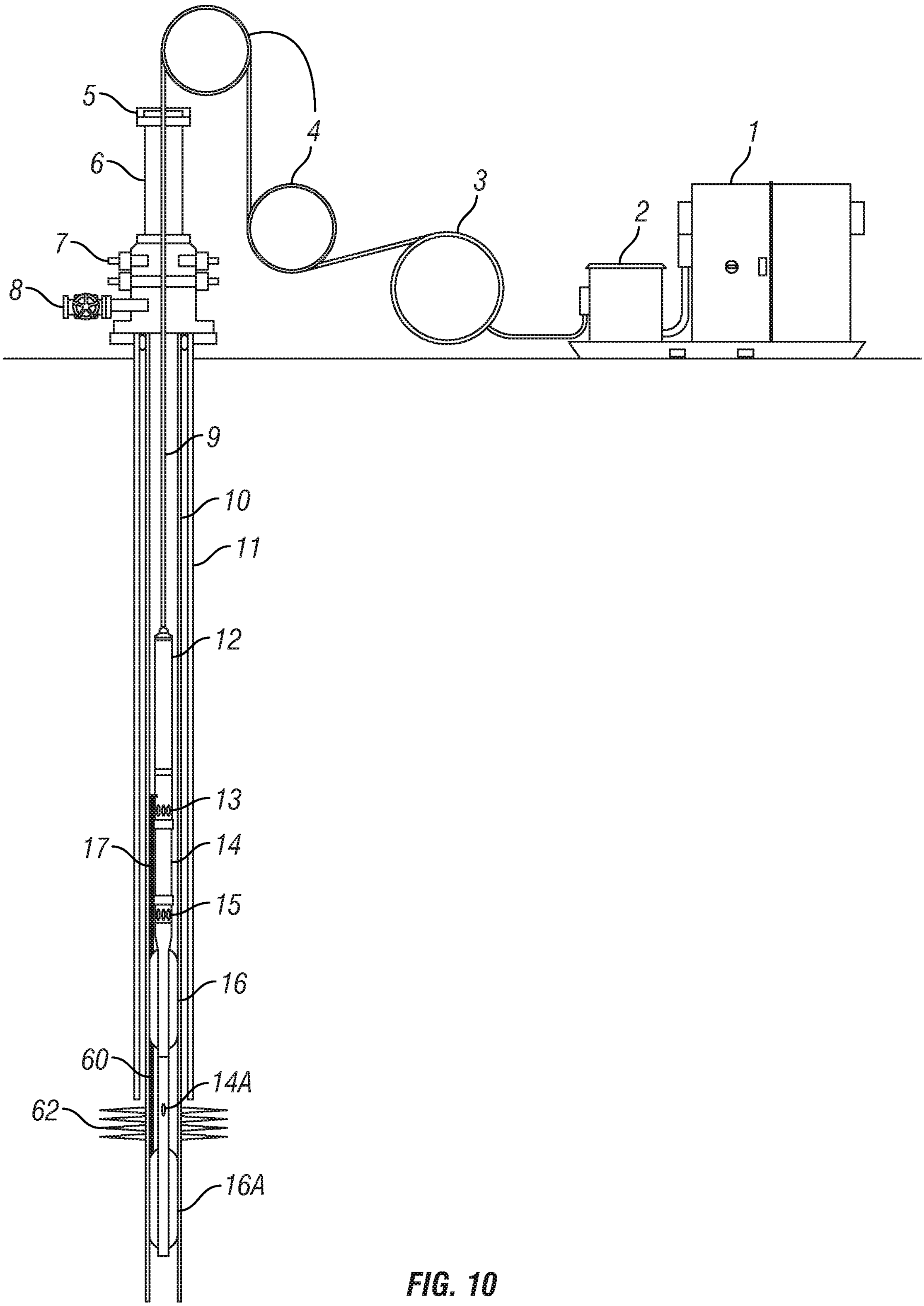


FIG. 10

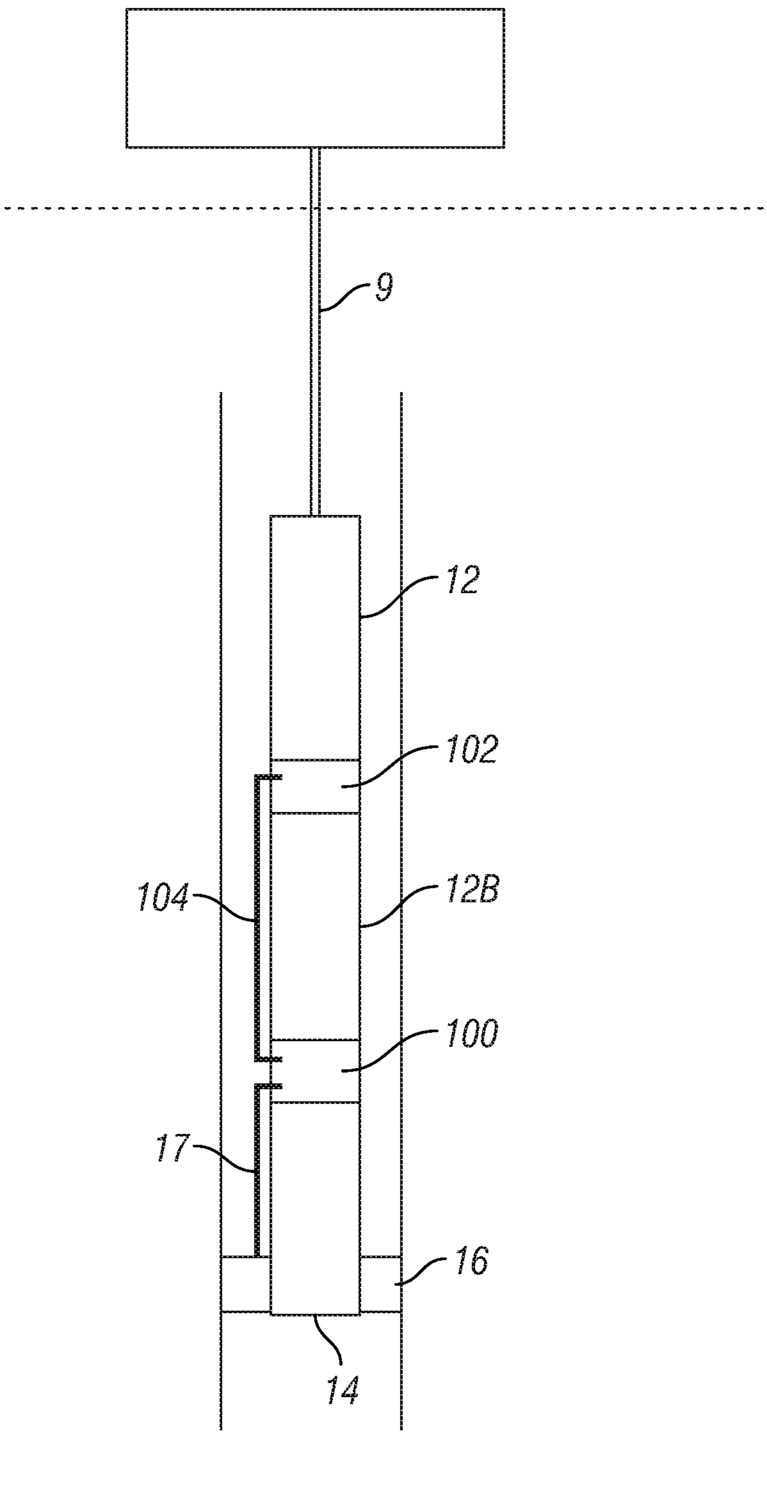
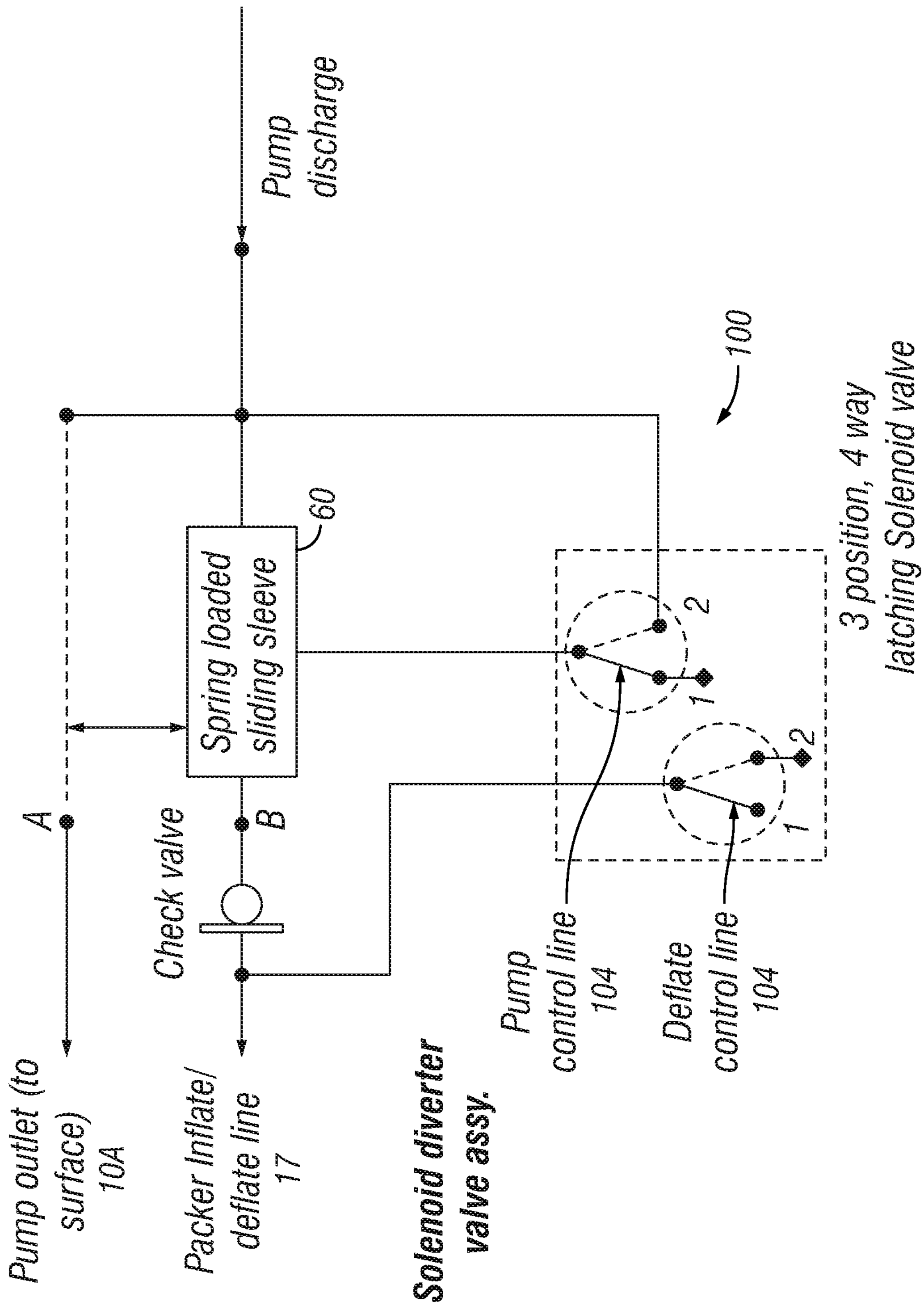


FIG. 11



Pump discharge
100
60
Spring loaded sliding sleeve
A
B
Check valve
2
1
2
1
3 position, 4 way latching Solenoid valve
Pump control line 104
Deflate control line 104
Pump outlet (to surface) 10A
Packer Inflate/ deflate line 17
Solenoid diverter valve assy.

FIG. 12

INTERNATIONAL SEARCH REPORT

International application No
PCT/GB2018/053647

A. CLASSIFICATION OF SUBJECT MATTER
INV. E21B33/127 E21B43/12 E21B34/08 E21B34/12
ADD.

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 2016/061010 A1 (SEARS KENNETH JOHN [GB] ET AL) 3 March 2016 (2016-03-03) paragraphs [0017], [0051] - [0060], [0075]; figures 1-9	1-21
A	WO 2009/113895 A1 (ORBAN JACQUES [RU]; VERCAEMER CLAUDE [FR]; SCHLUMBERGER CA LTD [US]; S) 17 September 2009 (2009-09-17) page 8, paragraph 3 - paragraph 6; figures 1-3	1-21
A	WO 2016/014793 A1 (SAUDI ARABIAN OIL CO [SA]; ARAMCO SERVICES CO [US]) 28 January 2016 (2016-01-28) paragraphs [0012], [0043] - [0045], [0056], [0067], [0068]; figures 1-2F	1-21

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[X] Further documents are listed in the continuation of Box C.

[X] See patent family annex.

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"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

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"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
22 February 2019	19/03/2019

Name and mailing address of the ISA/	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Fax: (+31-70) 340-3016	Jucker, Chava

INTERNATIONAL SEARCH REPORT

International application No
PCT/GB2018/053647

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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A	WO 2009/126792 A1 (BAKER HUGHES INC [US]; LOUGHLIN MICHAEL J [US]; MENDEZ LUIS E [US]) 15 October 2009 (2009-10-15) paragraphs [0006], [0012]; figure 3 -----	1-21

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No
PCT/GB2018/053647

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WO 2009126792 A1	15-10-2009	US 2009255691 A1	15-10-2009
		WO 2009126792 A1	15-10-2009