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Dewars et al.

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(54) **HYDRAULIC ANCHOR FOR DOWNHOLE PACKER**

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(22) Filed: **Jun. 21, 2014**

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Related U.S. Application Data

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(51) **Int. Cl.**

E21B 33/00	(2006.01)
E21B 33/124	(2006.01)
E21B 33/1295	(2006.01)

(52) **U.S. Cl.**
CPC ***E21B 33/00*** (2013.01); ***E21B 33/1243*** (2013.01); ***E21B 33/1295*** (2013.01)

(58) **Field of Classification Search**
USPC 166/373, 120
See application file for complete search history.

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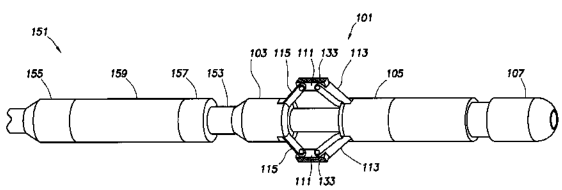
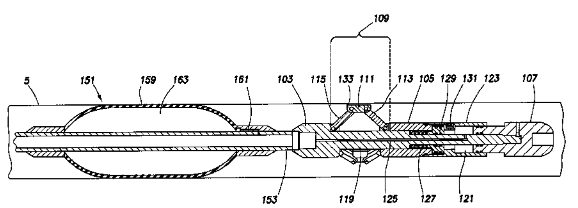
(57) **ABSTRACT**

A hydraulic anchor is coupled to a packer subassembly of a tool string. The hydraulic anchor, when actuated by fluid pressure, engages the surrounding wellbore, holding the tool string in place within the wellbore. A packer may then be actuated, held in position within the wellbore by the hydraulic anchor. In some embodiments, an inflatable packer may be held in the desired location by the hydraulic anchor. In some embodiments, a straddle packer assembly may be held in place by the hydraulic anchor. In some embodiments, a swellable packer may be held in place during the swelling process by the hydraulic anchor.

21 Claims, 16 Drawing Sheets





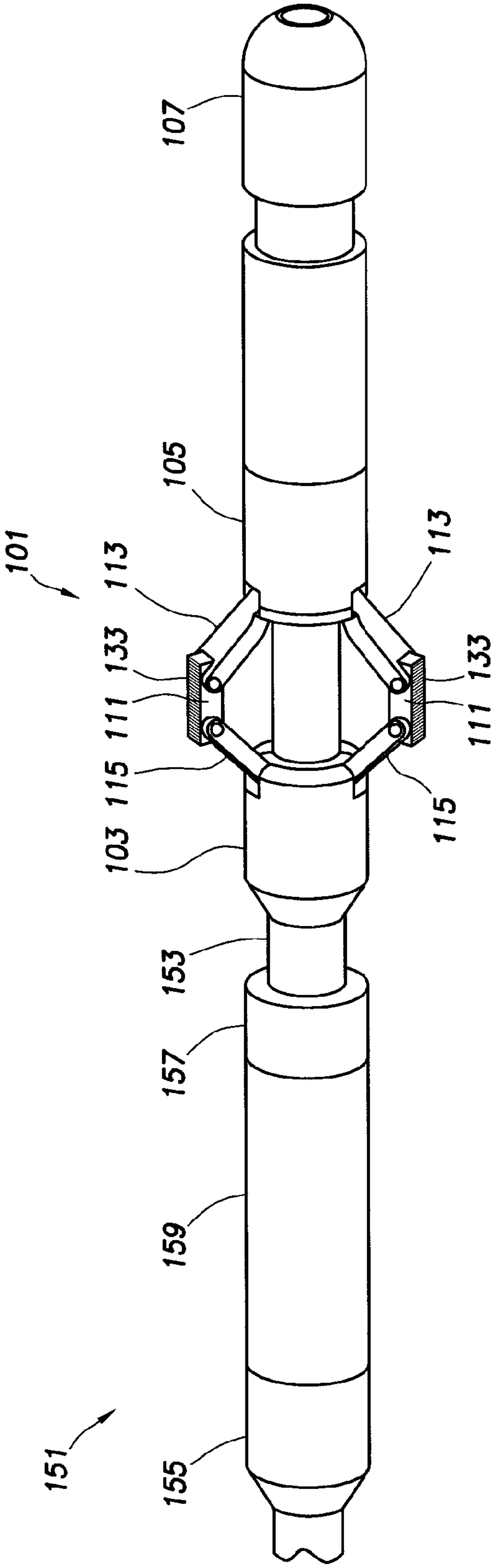


FIG.1

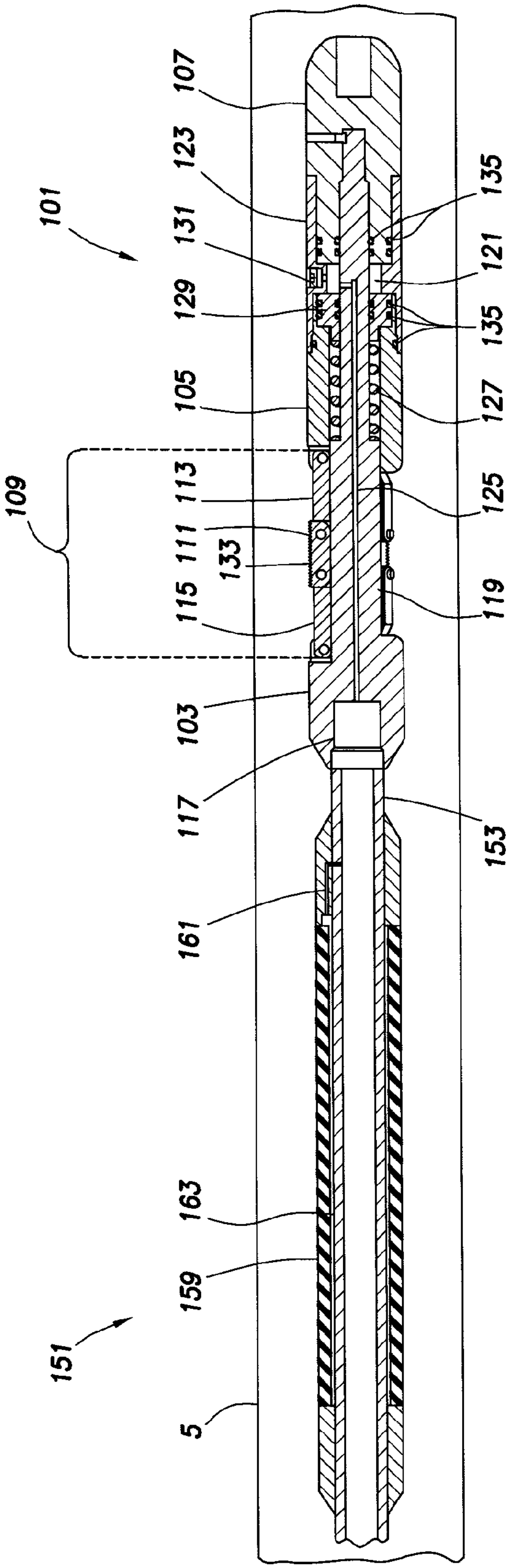


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FIG.2

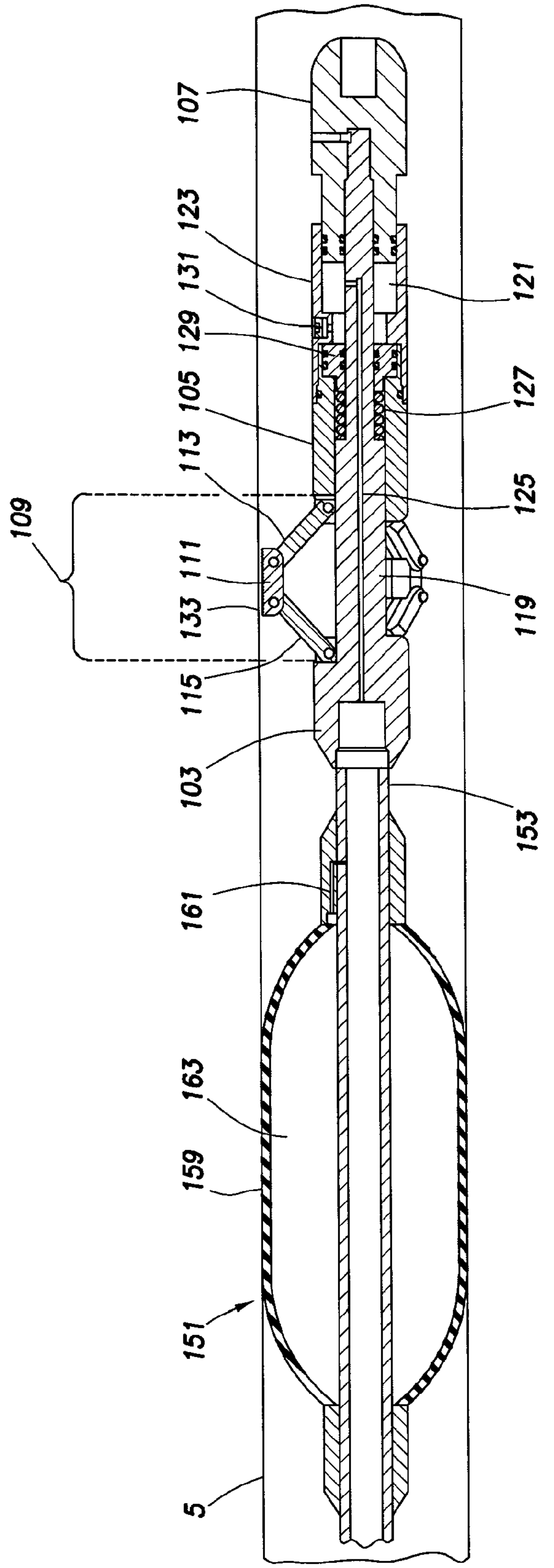
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FIG.3

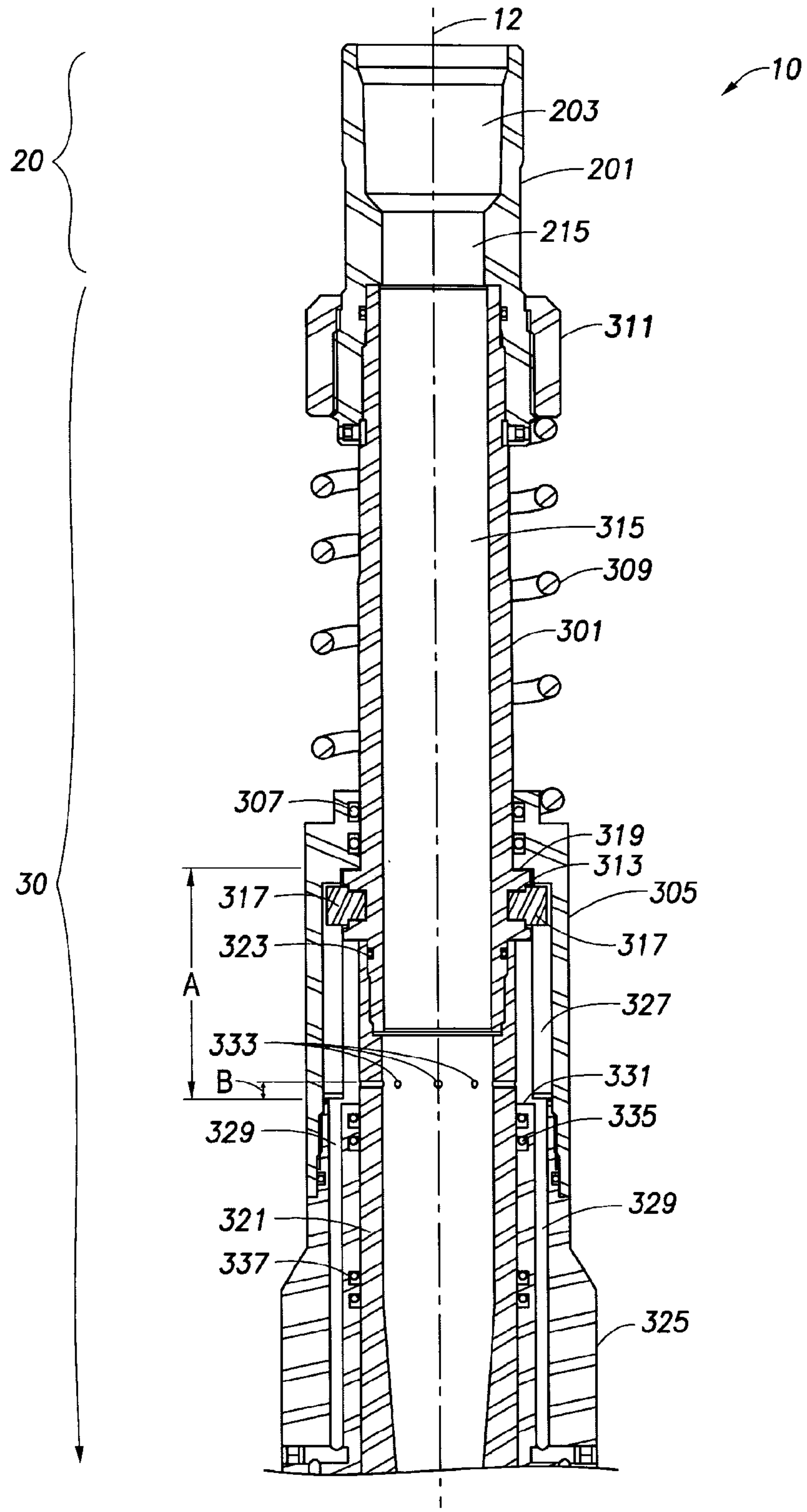
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FIG.4

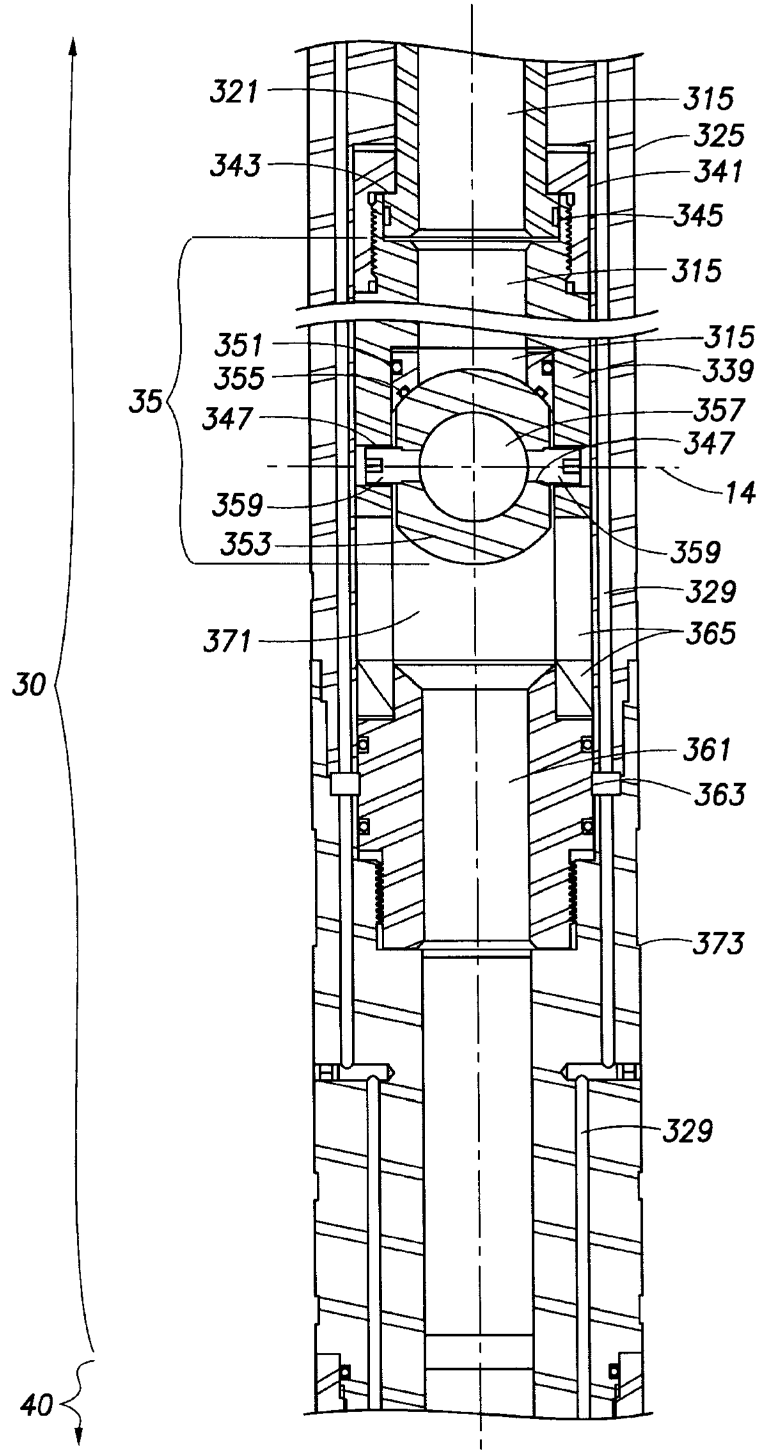
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FIG.5

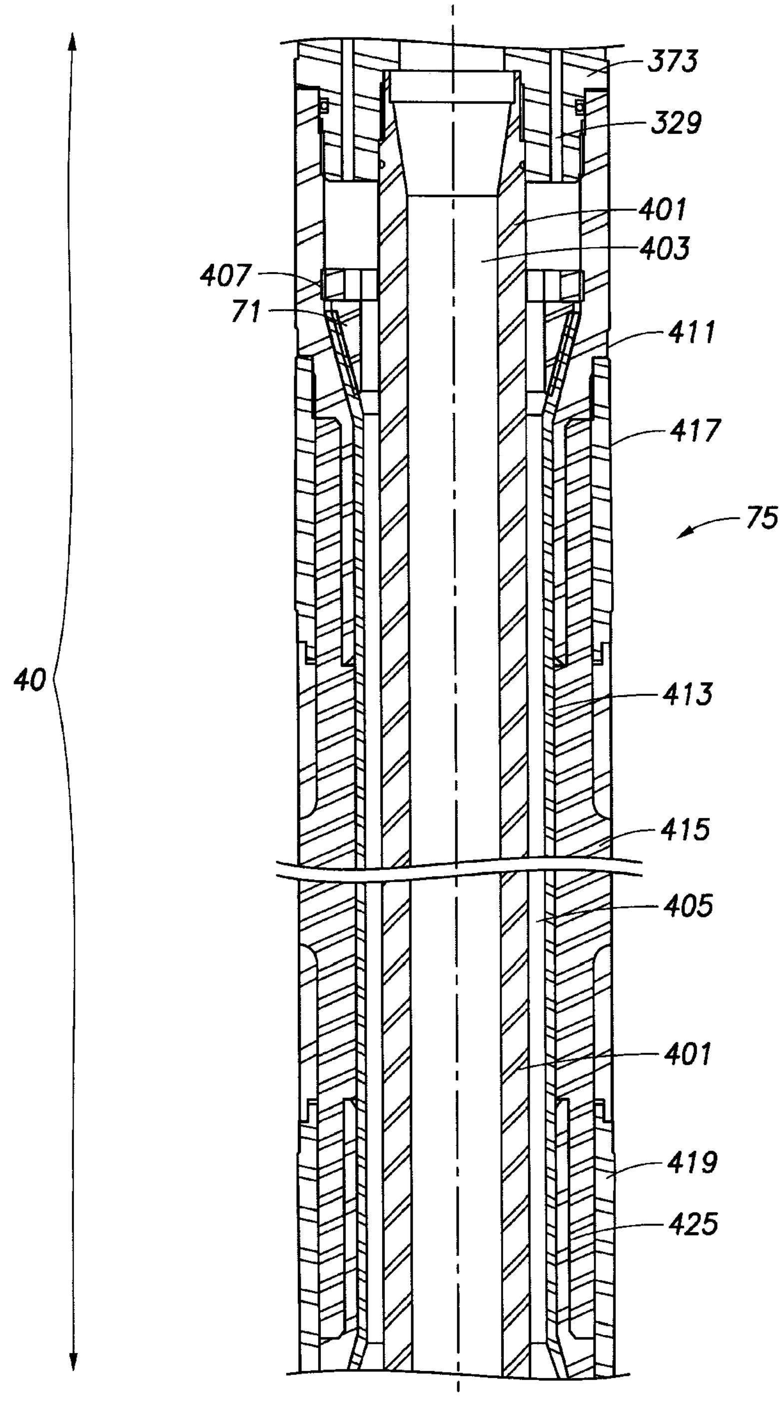


FIG.6

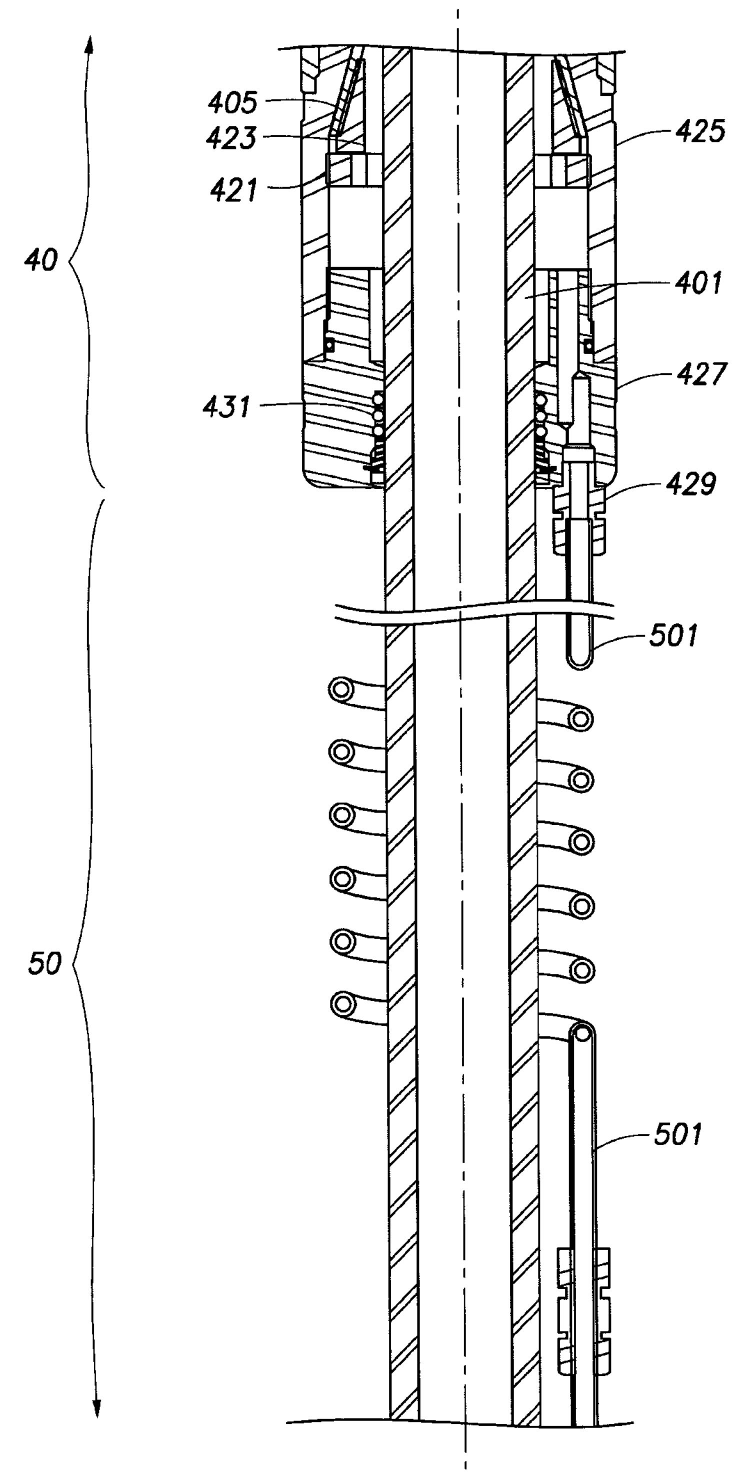


FIG.7

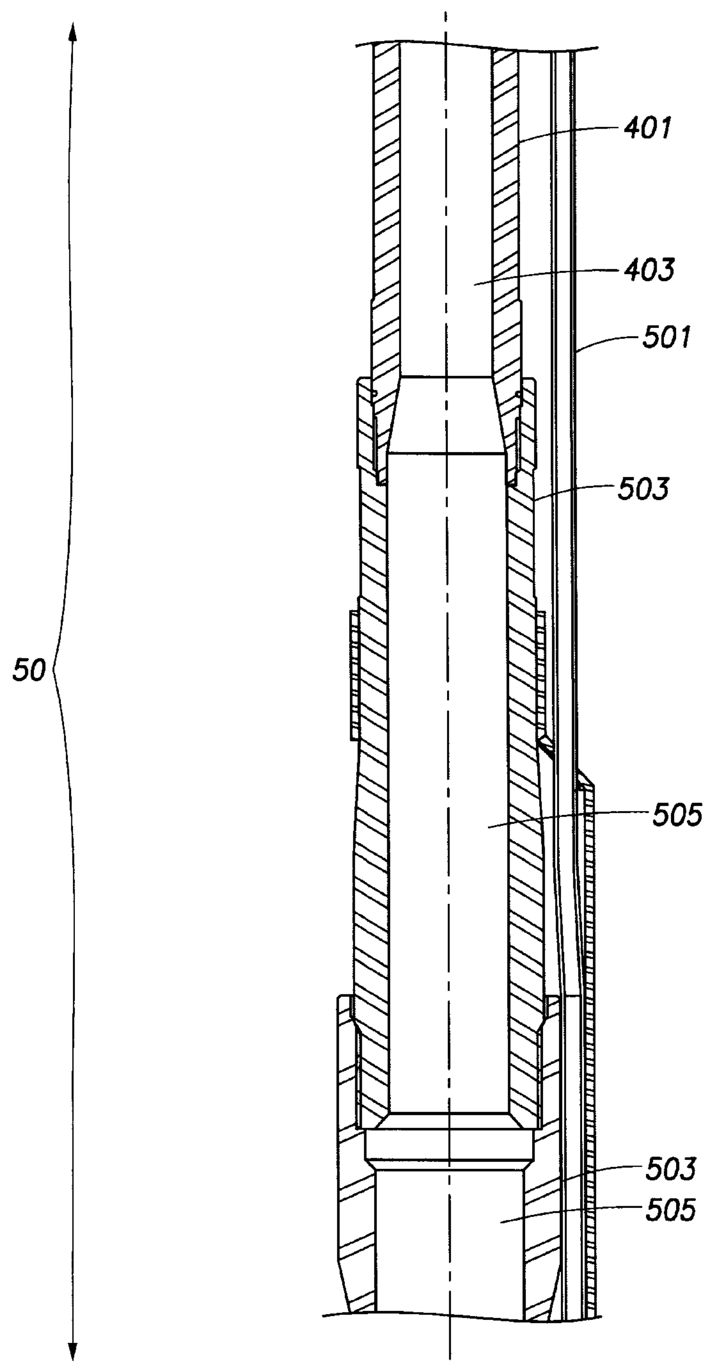


FIG.8

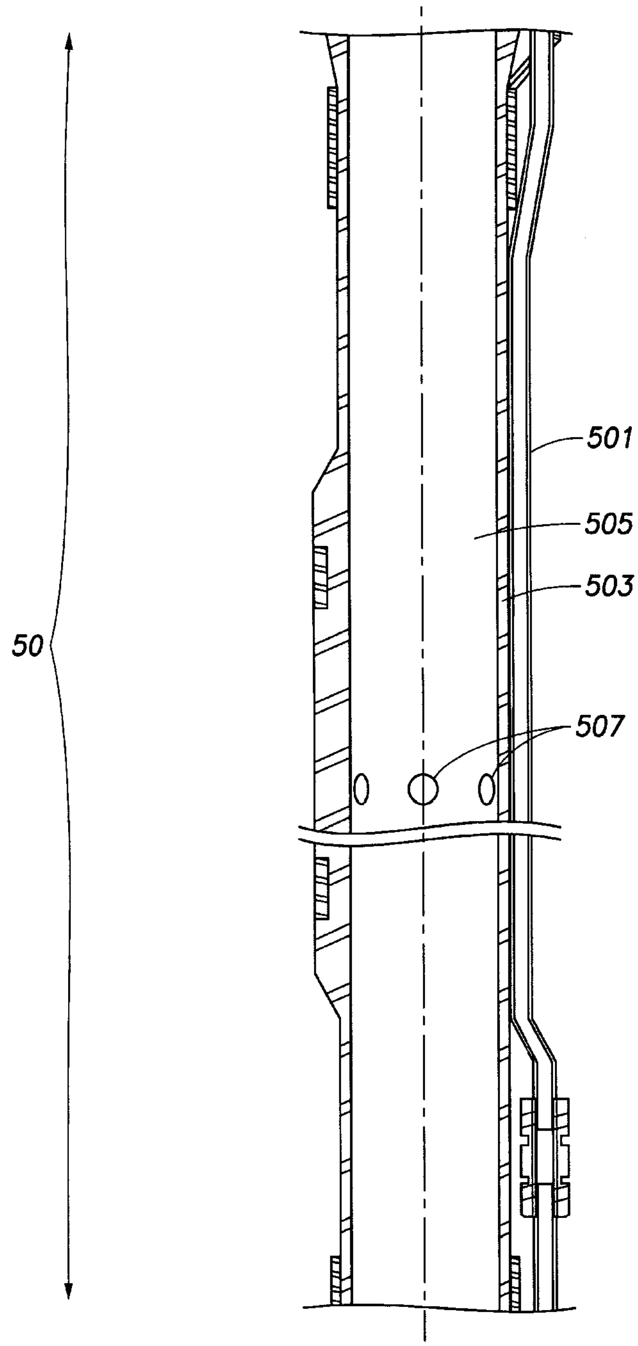


FIG.9

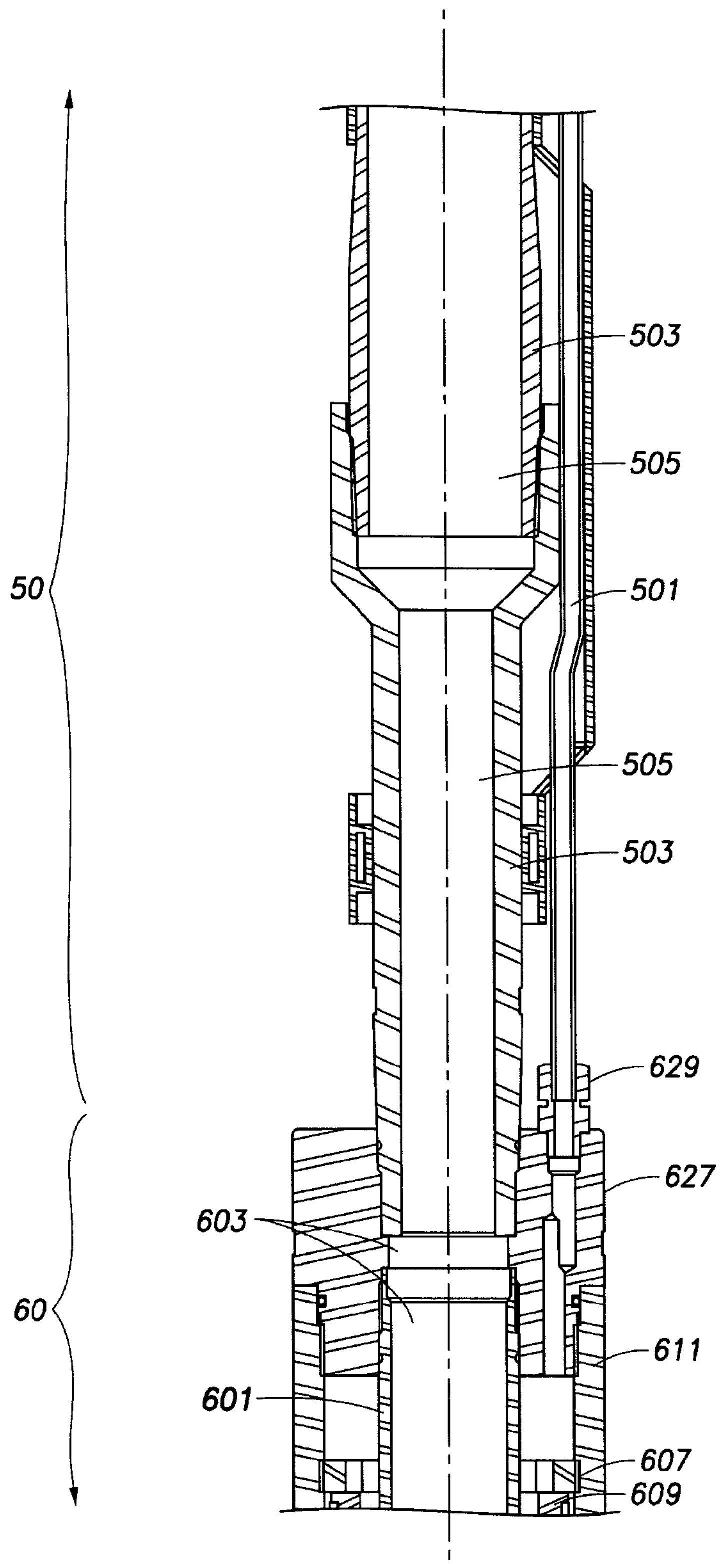


FIG. 10

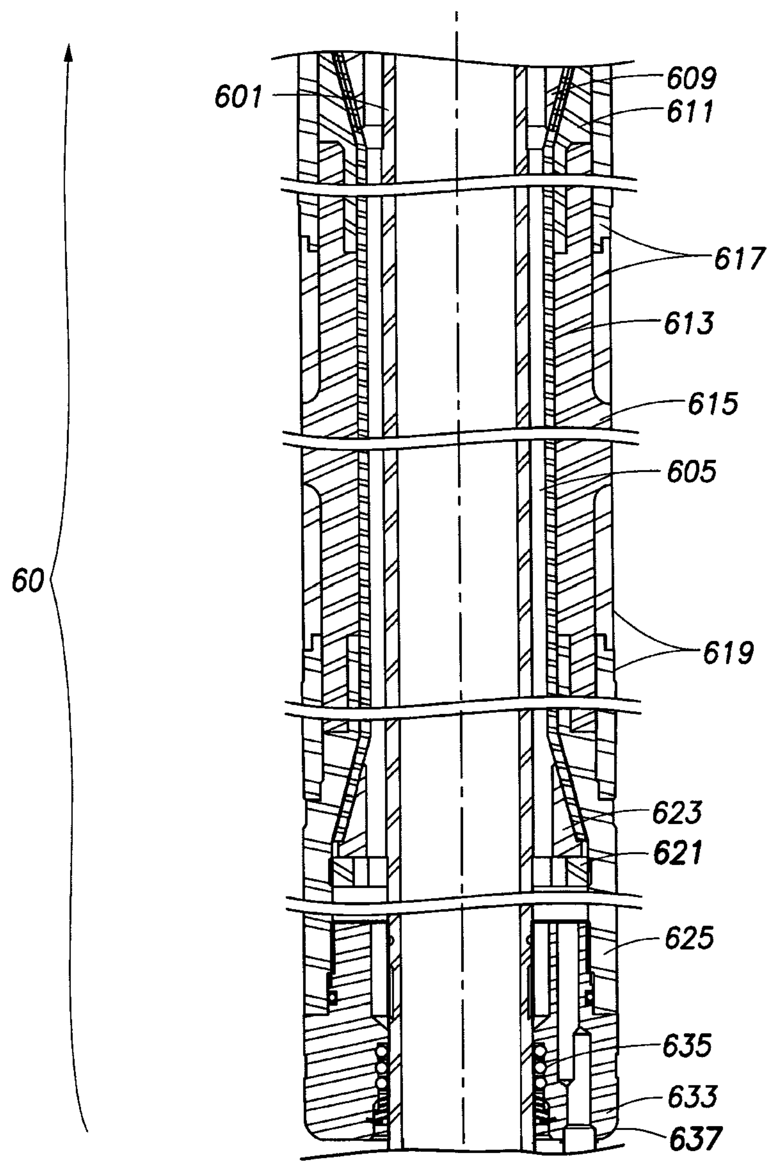
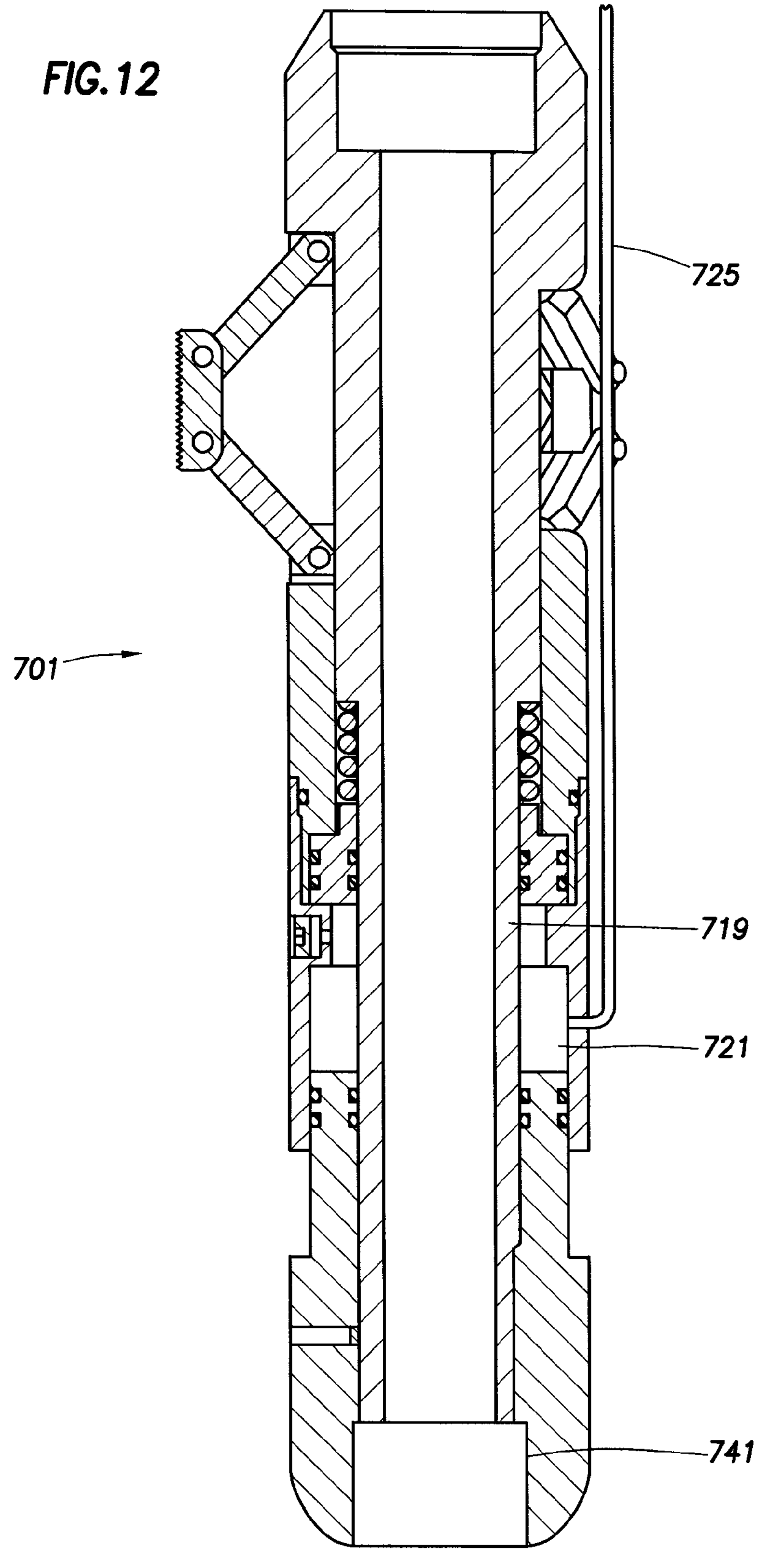


FIG. 11

FIG. 12



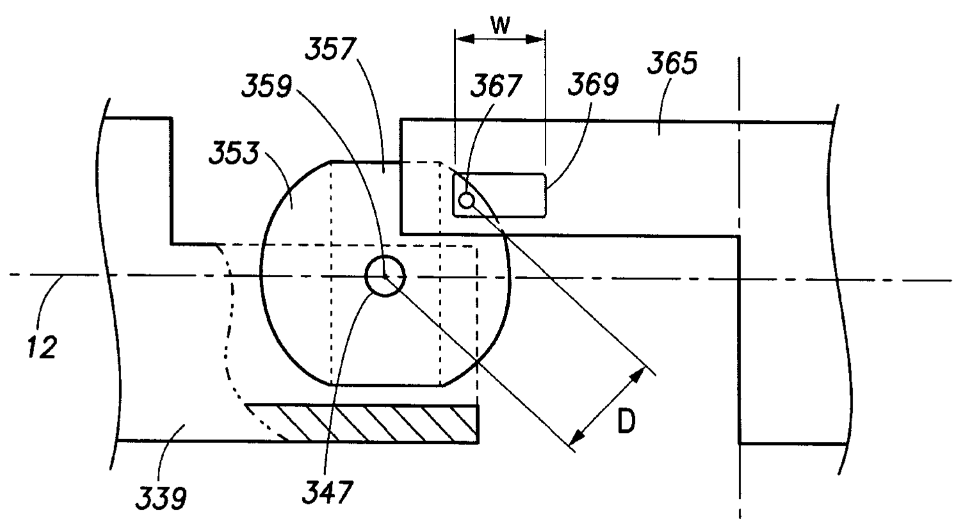


FIG. 13A

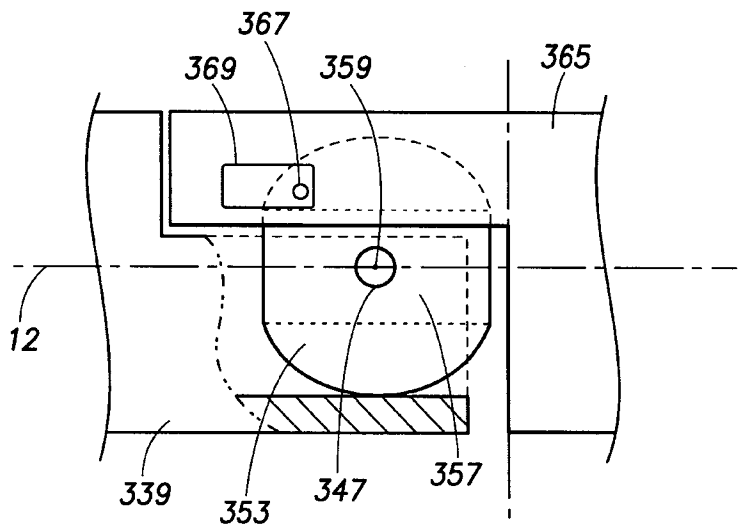


FIG. 13B

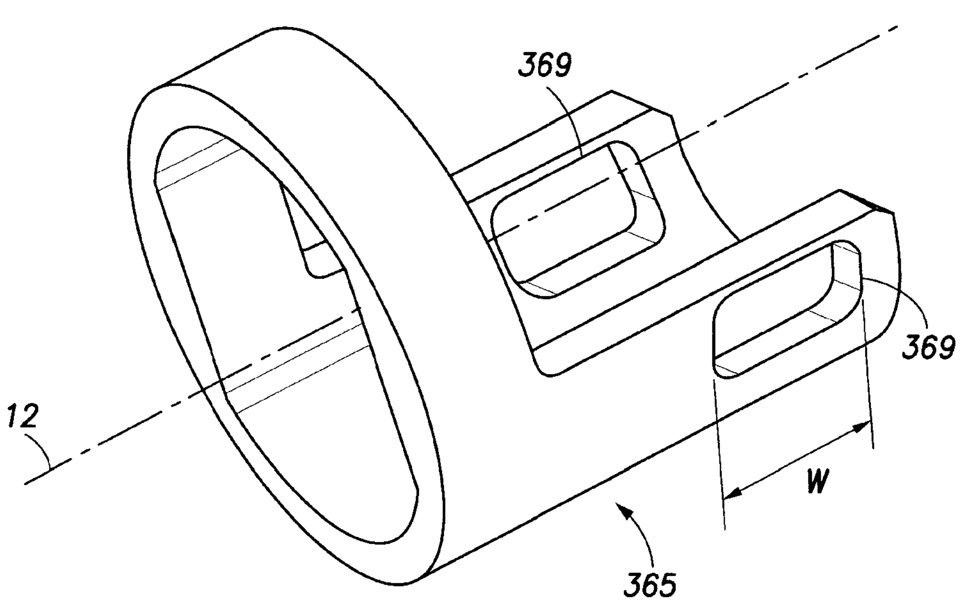


FIG. 14

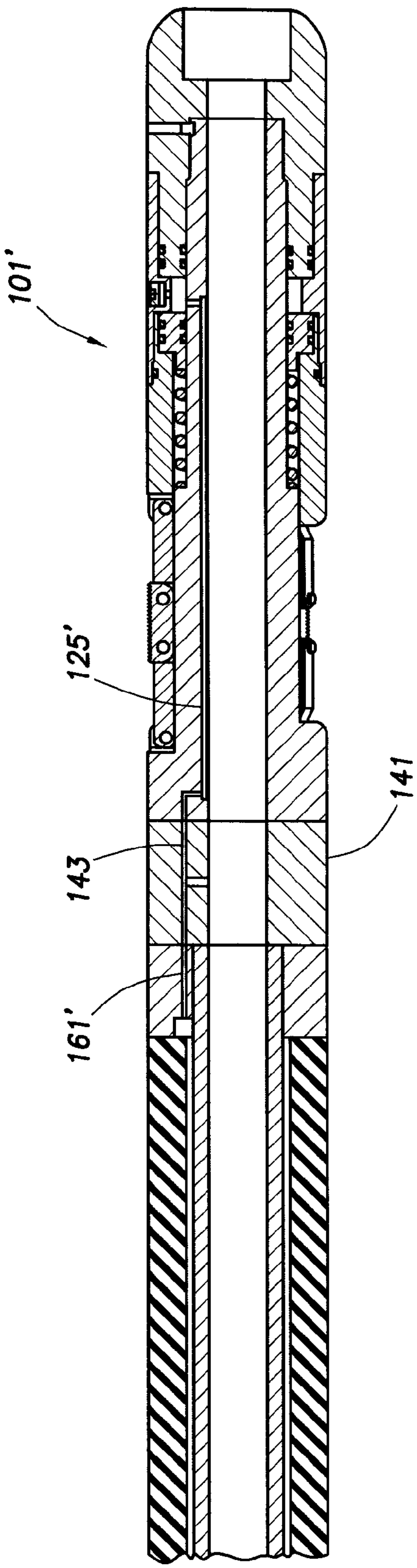


FIG. 15

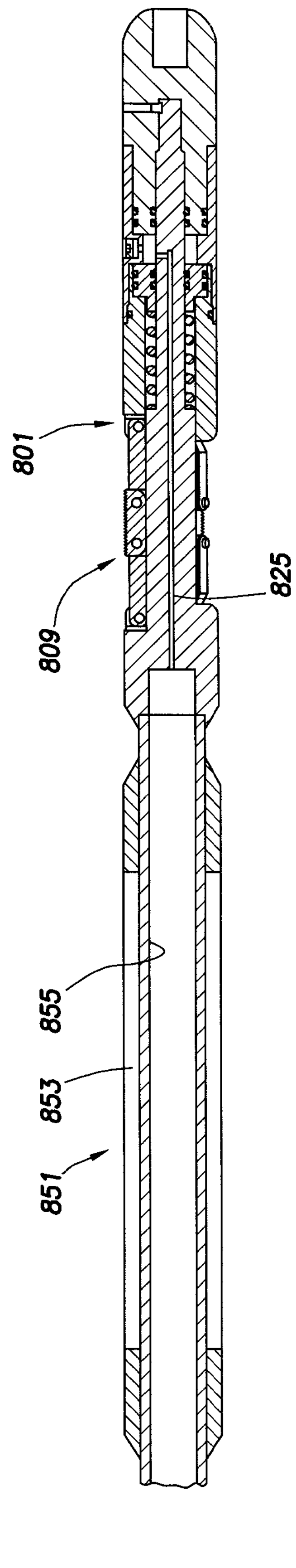


FIG. 16

HYDRAULIC ANCHOR FOR DOWNHOLE PACKER

CROSS-REFERENCE TO RELATED APPLICATIONS

This application is a non-provisional application which claims priority from U.S. provisional application No. 61/837,876, filed Jun. 21, 2013, the entirety of which is hereby incorporated by reference; and from U.S. provisional application No. 61/926,571, filed Jan. 13, 2014, the entirety of which is hereby incorporated by reference.

TECHNICAL FIELD/FIELD OF THE DISCLOSURE

The present disclosure relates generally to downhole tools for positioning a tool string, and more specifically to a downhole tool for maintaining the position of a tool string within a wellbore.

BACKGROUND OF THE DISCLOSURE

In drilling an oil well, a variety of operations may be carried out on a wellbore. For certain operations, the accurate positioning of a tool within the well may be critical. As an example, operations such as acidizing, fracturing, flow testing, washing perforations or pressure testing may specifically target a certain section of wellbore. In these operations, the targeted section of wellbore may be isolated from the wellbore areas both above and below. For these operations, a "straddle packer" assembly may be utilized.

A straddle packer may include inflatable packers positioned on either side of the wellbore section to be treated. Connecting the packers is a tubular member which may include at least one selectively openable port. In order to effectively treat the section of wellbore, positioning of the straddle packer is very important, as the targeted section of wellbore must be between the upper and lower packers so that the ported tubular may act thereon. While the packers are inflated, until contact is made with the wellbore, the straddle packer assembly may move undesirably within the wellbore. Additionally, to ensure the straddle packer assembly remains in position, a portion of the contact area between each packer and the wellbore is typically made up of metal slats. The slats, though effective in preventing movement of the packer, are not as effective in sealing against the wellbore as the flexible outer bladder of the packer.

SUMMARY

The present disclosure provides for a downhole tool for use within a wellbore. The downhole tool may include a hydraulic anchor. The hydraulic anchor may include a tool body. The tool body may include a generally cylindrical mandrel, the mandrel having an interior. The tool body may also include a coupler positioned to allow the tool body to couple to a tubular member. The hydraulic anchor may also include a stroking sleeve. The stroking sleeve may be generally tubular, and may be positioned to slide along the mandrel of the tool body. The hydraulic anchor may also include an actuation cylinder, the actuation cylinder formed between the stroking sleeve and the tool body. The actuation cylinder may be fluidly coupled to the interior of the mandrel. The hydraulic anchor may also include an extendible arm. The extendible arm may include a grip plate, a first extension linkage, and a second extension linkage. The first

extension linkage may be pivotably coupled between the tool body and the grip plate. The second extension linkage may be pivotably coupled between the grip plate and the stroking sleeve. The downhole tool may also include an inflatable packer. The inflatable packer may include a packer mandrel, the packer mandrel having an interior. The inflatable packer may also include a packer bladder, the packer bladder being generally tubular in shape and positioned about the packer mandrel. The inflatable packer may also include a packer inflation port, the packer inflation port formed in the packer mandrel and positioned to couple the interior of the packer mandrel with the annular space between the packer mandrel and the packer bladder.

The present disclosure also provides for a downhole tool for use within a wellbore. The downhole tool may include a hydraulic anchor. The hydraulic anchor may include a tool body, the tool body including a generally cylindrical mandrel having an interior. The tool body may include a coupler positioned to allow the tool body to couple to a tubular member. The hydraulic anchor may also include a stroking sleeve, the stroking sleeve being generally tubular and positioned to slide along the mandrel of the tool body. The hydraulic anchor may also include an actuation cylinder formed between the stroking sleeve and the tool body. The actuation cylinder may be fluidly coupled to the interior of the mandrel. The hydraulic anchor may also include an extendible arm. The extendible arm may include a grip plate, a first extension linkage, and a second extension linkage. The first extension linkage may be pivotably coupled between the tool body and the grip plate. The second extension linkage may be pivotably coupled between the grip plate and the stroking sleeve. The downhole tool may also include a swellable packer. The swellable packer may include a packer mandrel, the packer mandrel having an interior. The packer mandrel may be coupled to the tool body. The swellable packer may also include an elastomeric swellable body, the elastomeric swellable body being generally tubular in shape and positioned about the packer mandrel.

The present disclosure also provides for a method. The method may include positioning a tool string within a wellbore. The tool string may include a hydraulic anchor. The hydraulic anchor may include a tool body, the tool body including a generally cylindrical mandrel having an interior. The tool body may include a coupler positioned to allow the tool body to couple to a tubular member. The hydraulic anchor may also include a stroking sleeve being generally tubular and positioned to slide along the mandrel of the tool body. The hydraulic anchor may also include an actuation cylinder formed between the stroking sleeve and the tool body. The actuation cylinder may be fluidly coupled to the interior of the mandrel. The hydraulic anchor may also include an extendible arm. The extendible arm may include a grip plate, a first extension linkage, and a second extension linkage. The first extension linkage may be pivotably coupled between the tool body and the grip plate. The second extension linkage may be pivotably coupled between the grip plate and the stroking sleeve. The tool string may also include a swellable packer. The swellable packer may include a packer mandrel having an interior. The packer mandrel may be coupled to the tool body. The swellable packer may include an elastomeric swellable body, the elastomeric swellable body being generally tubular in shape and positioned about the packer mandrel. The method may further include applying fluid pressure to the actuation cylinder. The method may further include extending the extendible arm, the extendible arm contacting the surround-

ing wellbore. The method may further include exposing the elastomeric swellable body to a swelling fluid, the elastomeric swellable body increasing in volume to form a seal between the packer mandrel and the wellbore.

The present disclosure also provides for a method. The method may include positioning a tool string within a wellbore. The tool string may include a hydraulic anchor. The hydraulic anchor may include a tool body, the tool body including a generally cylindrical mandrel having an interior. The tool body may include a coupler positioned to allow the tool body to couple to a tubular member. The hydraulic anchor may also include a stroking sleeve being generally tubular and positioned to slide along the mandrel of the tool body. The hydraulic anchor may also include an actuation cylinder formed between the stroking sleeve and the tool body. The actuation cylinder may be fluidly coupled to the interior of the mandrel. The hydraulic anchor may also include an extendible arm. The extendible arm may include a grip plate, a first extension linkage, and a second extension linkage. The first extension linkage may be pivotably coupled between the tool body and the grip plate. The second extension linkage may be pivotably coupled between the grip plate and the stroking sleeve. The tool string may also include an inflatable packer. The inflatable packer may include a packer mandrel, the packer mandrel having an interior. The inflatable packer may include a packer bladder, the packer bladder being generally tubular in shape and positioned about the packer mandrel. The inflatable packer may include a packer inflation port formed in the packer mandrel and positioned to couple the interior of the packer mandrel with the annular space between the packer mandrel and the packer bladder. The method may also include applying fluid pressure to the actuation cylinder, and extending the extendible arm, the extendible arm contacting the surrounding wellbore. The method may also include applying fluid pressure to the packer inflation port, inflating the inflatable packer.

The present disclosure also provides for a downhole tool on a tool string having a tool string bore positionable in a wellbore having a wellbore axis. The downhole tool may include a first packer sub coupled to the tool string, the packer sub having a first inflatable element and a first packer inflation port. The downhole tool may also include a valve sub coupled to the tool string. The valve sub may include a valve sub housing, the valve sub housing being generally tubular having at least one packer supply port in fluid communication with the packer inflation port. The valve sub may further include a control tube, the control tube being generally tubular and aligned with the valve sub housing and having an upper and lower end, the upper end coupled to the tool string, and the lower end positioned within the bore of the valve sub housing. The control tube may have a bore and at least one aperture through its side wall. The control tube may have an open position in which the aperture provides fluid communication between the bore of the control tube and the packer supply port and a closed position in which the apertures are covered by the inner wall of the valve sub housing and the bore of the control tube. The control tube bore may be in fluid communication with the tool string bore. The valve sub may further include a shift sleeve coupled to the lower end of the control tube having a hole adapted to accept an axle pin. The valve sub may further include a rotatable ball adapted to rotate about the axle pin. The rotatable ball may have at least one flow path through its body. The rotatable ball may have an open position and a closed position selected by the upward or downward movement of the tool string. The open and closed positions of the rotatable ball may be in opposition to the open and closed position of the control tube, thereby allowing or preventing fluid flow through the at least one flow path from the tool string bore and the bore of the control tube. The rotatable ball may have a rotation pin extending from its outer surface. The valve sub may include a rotation pin sleeve coupled to the rotation pin and adapted to rotate the ball from the closed position to the open position in response to a movement of the ball toward or away from the rotation pin sleeve. The downhole tool may also include a hydraulic anchor. The hydraulic anchor may include a tool body, the tool body including a generally cylindrical mandrel having an interior. The tool body may include a coupler positioned to allow the tool body to couple to a tubular member. The hydraulic anchor may also include a stroking sleeve being generally tubular and positioned to slide along the mandrel of the tool body. The hydraulic anchor may also include an actuation cylinder formed between the stroking sleeve and the tool body. The actuation cylinder may be fluidly coupled to the interior of the mandrel. The hydraulic anchor may also include an extendible arm. The extendible arm may include a grip plate, a first extension linkage, and a second extension linkage. The first extension linkage may be pivotably coupled between the tool body and the grip plate. The second extension linkage may be pivotably coupled between the grip plate and the stroking sleeve.

BRIEF DESCRIPTION OF THE DRAWINGS

The present disclosure is best understood from the following detailed description when read with the accompanying figures. It is emphasized that, in accordance with the standard practice in the industry, various features are not drawn to scale. In fact, the dimensions of the various features may be arbitrarily increased or reduced for clarity of discussion.

FIG. **1** depicts a perspective view of a hydraulic anchor consistent with embodiments of the present disclosure.

FIG. **2** depicts a cross section view of the hydraulic anchor of FIG. **1** in the run-in position.

FIG. **3** depicts a cross section view of the hydraulic anchor of FIG. **1** in the set position.

FIG. **4** is a partial cross section of a straddle packer assembly consistent with embodiments of the present disclosure.

FIG. **5** is a continuation of the partial cross section of FIG. **4**.

FIG. **6** is a continuation of the partial cross section of FIG. **5**.

FIG. **7** is a continuation of the partial cross section of FIG. **6**.

FIG. **8** is a continuation of the partial cross section of FIG. **7**.

FIG. **9** is a continuation of the partial cross section of FIG. **8**.

FIG. **10** is a continuation of the partial cross section of FIG. **9**.

FIG. **11** is a continuation of the partial cross section of FIG. **10**.

FIG. **12** is a continuation of the partial cross section of FIG. **11**.

FIG. **13**A is a partial cross section of components of the straddle packer assembly of FIG. **4** in a "run-in configuration" consistent with at least one embodiment of the present disclosure.

FIG. **13**B is a partial cross section of the components depicted in FIG. **13**A in an "actuated configuration" consistent with at least one embodiment of the present disclosure.

FIG. **14** is a perspective view of a rotation pin sleeve consistent with at least one embodiment of the present disclosure.

FIG. **15** is a partial cross section of a hydraulic anchor consistent with embodiments of the present disclosure.

FIG. **16** is a partial cross section of a hydraulic anchor consistent with embodiments of the present disclosure.

DETAILED DESCRIPTION

It is to be understood that the following disclosure provides many different embodiments, or examples, for implementing different features of various embodiments. Specific examples of components and arrangements are described below to simplify the present disclosure. These are, of course, merely examples and are not intended to be limiting. In addition, the present disclosure may repeat reference numerals and/or letters in the various examples. This repetition is for the purpose of simplicity and clarity and does not in itself dictate a relationship between the various embodiments and/or configurations discussed.

As depicted in FIG. **1**, hydraulic anchor **101** may be coupled to inflatable packer assembly **151**. Inflatable packer assembly **151** may be a part of, for example and without limitation, a single packer or straddle packer assembly. Hydraulic anchor **101** may include tool body **103**, stroking sleeve **105** and one or more extendible arms **109**. Extendible arms **109** may include grip plate **111** and extension linkages **113**, **115**. Extension linkages **113**, **115** may be coupled to stroking sleeve **105** and tool body **103** respectively to move grip plate **111** radially inward or outward in response to a movement of stroking sleeve **105** towards or away from tool body **103**. In some embodiments, tool body **103** is pivotably coupled to extension linkage **115** and stroking sleeve **105** is likewise pivotably coupled to extension linkage **113**. In some embodiments, extension linkages **113**, **115** are likewise pivotably coupled to grip plate **111**.

Inflatable packer assembly **151**, as understood in the art, may include tubular member **153**, upper and lower housings **155**, **157**, and packer bladder **159**. In some embodiments, inflatable packer assembly **151** relies on hydraulic anchor **101** to prevent movement within the wellbore and thus may include no external slats.

As depicted in FIGS. **2**, **3**, tool body **103** may include coupler **117** positioned to allow hydraulic anchor **101** to connect to tubular member **153**. Coupler **117** may be a threaded box connector as understood in the art. One having ordinary skill in the art with the benefit of this disclosure will understand that coupler **117** may be any sort of connector suitable for coupling hydraulic anchor **101** to tubular member **153**. Furthermore, one having ordinary skill in the art with the benefit of this disclosure will understand that tubular member **153** may include any tubular member for use in a wellbore, including, without limitation, a tool such as packer assembly **151**, or a section of drill pipe, a perforating gun, etc.

In some embodiments, tool body **103** may further include mandrel **119**. Mandrel **119** may be generally cylindrical so that stroking sleeve **105** may slide along mandrel **119** in response to hydraulic pressure introduced into actuation cylinder **121**. In some embodiments, actuation cylinder **121** may be formed in a space between mandrel **119** and lower extension **123** of stroking sleeve **105**. In some embodiments, as depicted in FIGS. **1**, **2**, and **3**, lower extension **123** may be formed as a separate piece from stroking sleeve **105** and may be coupled thereto by, for example, a threaded connection. In some embodiments, tool body **103** may include lower sub **107** coupled to mandrel **119**. In some embodiments, lower sub **107** may form a wall of actuation cylinder **121**. Mandrel **119** may couple to lower sub **107** by, for example, a threaded connection. Lower sub **107** may have a rounded profile to, for example, help guide hydraulic anchor **101** through the wellbore as it is inserted.

Fluid may be supplied to actuation cylinder **121** via actuation port **125**. In some embodiments, actuation port **125** may be formed through the interior of mandrel **119**. Actuation port **125** may extend between the interior of tubular member **153** coupled to coupler **117** and actuation cylinder **121**. As fluid pressure within actuation cylinder **121** increases, for example, as a result of an increase in fluid pressure within a tubular member **153**, stroking sleeve **105** moves from the run-in position depicted in FIG. **2** to the set position as depicted in FIG. **3**. As stroking sleeve **105** moves along mandrel **119**, extendible arm **109** extends outward from mandrel **119**. As the length between tool body **103** and stroking sleeve **105** decreases, extension linkages **113**, **115** may cause grip plate **111** to move outward until grip plate **111** contacts the surrounding wellbore **5** thus holding hydraulic anchor **101** in place within wellbore **5**. Further pressure increase may, for example, exert additional force between grip plate **111** and wellbore **5**, thus, for example, increasing the strength at which hydraulic anchor **101** is held in place within the wellbore.

Also in response to the increase in fluid pressure, fluid flows through packer actuation port **161** from the interior of tubular member **153**. Packer actuation port **161** may be coupled to the interior **163** of packer bladder **159**. As fluid pressure increases within the interior **163** of packer bladder **159**, packer bladder **159** expands from the run-in position depicted in FIG. **2** to the set position as depicted in FIG. **3**, sealing against wellbore **5**. In some embodiments, packer actuation port **161** may further include a valve apparatus positioned between the interior of tubular member **153** and the interior **163** of packer bladder **159**. In some embodiments, the valve may prevent or restrict the inflation of packer bladder **159** until, for example, hydraulic anchor **101** has fully engaged wellbore **5**.

When it is desired to move hydraulic anchor **101**, pressure is bled from the interior of tubular member **153**. Packer bladder **159** thus deflates into the interior of tubular member **153**. Likewise, pressure is bled from actuation cylinder **121**. In some embodiments, spring **127** may be positioned to return stroking sleeve **105** to the run-in position. Spring **127** may be retained by piston **129** coupled to stroking sleeve **105**. Spring **127** may, for example, assist stroking sleeve **105** to move back along mandrel **119**. As the distance between tool body **103** and stroking sleeve **105** increases, extension linkages **113**, **115** may cause grip plate **111** to move inward, away from the wall of the surrounding wellbore, thus releasing hydraulic anchor **101** from the wellbore.

In some embodiments, rupture disc **131** may be positioned in fluid communication with actuation cylinder **121** and the surrounding wellbore. Rupture disc **131** is positioned to release pressure within actuation cylinder **121** in the event that the differential pressure therebetween reaches a predetermined threshold value. The threshold value may be determined to, for example, prevent damage to either hydraulic anchor **101** or the surrounding wellbore. Additionally, if fluid becomes trapped in actuation cylinder **121** by, for example, a blockage in actuation port **125**, a sufficiently strong pull on hydraulic anchor **101** from the attached tubular member may cause rupture disc **131** to rupture and release the pressure, allowing extension arms **109** of hydraulic anchor **101** to retract. As hydraulic anchor **101** is pulled upward within the wellbore, the resultant force of the wellbore may cause a downward movement of grip plate **111**, which translates into a movement of stroking sleeve **105**. This movement of stroking sleeve **105** may decrease the volume of actuation cylinder **121**, thus causing an increase in pressure within actuation cylinder **121**. Sufficient increase in pressure may thus cause rupture disc **131** to fail.

In some embodiments, as depicted in FIGS. **2**, **3**, rupture disc **131** may be positioned on lower extension **123**. In other embodiments, one having ordinary skill in the art with the benefit of this disclosure will understand that rupture disc **131** may be positioned at any location and on any component in fluid communication with actuation cylinder **121** positioned to release pressure from within actuation cylinder **121** into the surrounding wellbore.

In some embodiments, grip plate **111** may include a surface texture to, for example, increase resistance to the slipping of grip plate **111** along the surrounding wellbore. As depicted in FIGS. **1-3**, the surface texture may include ridges **133**. One having ordinary skill in the art with the benefit of this disclosure will understand that any surface texture may be substituted for ridges **133** without deviating from the scope of this disclosure. For example, the surface texture may include, without limitation, ridges, spikes, knurling, teeth, or any combination thereof.

In some embodiments, one or more seals **135** may be positioned to, for example, retain fluid pressure within actuation cylinder **121**. Seals **135** may be positioned between lower sub **107** and mandrel **119**, mandrel **119** and stroking sleeve **105** (or any related component including spring retention nut **129** as shown), between components of stroking sleeve **105** (including between stroking sleeve **105**, lower extension **123**, or spring retention nut **129**, and/or between lower extension **123** and lower sub **107**).

In some embodiments, hydraulic anchor **101** may be designed such that hydraulic anchor **101** engages wellbore **5** before the inflatable packers begin to inflate. Likewise, hydraulic anchor **101** may be designed such that the inflatable packers fully deflate before hydraulic anchor **101** releases. Such a configuration may, for example, prevent damage to either wellbore **5** or inflatable packer **151** from movement of a partially inflated packer within the wellbore.

Although mandrel **119** is depicted as a solid member having actuation port **125** formed therein, one having ordinary skill in the art with the benefit of this disclosure will understand that mandrel **119** may instead be, for example, a tubular member. Actuation port **125** may, in such an embodiment, be formed within the wall of mandrel **119** or as an external control line. For example, FIG. **15** depicts a mechanical anchor **101'** having actuation port **125'** formed in the wall of mandrel **119'**. Actuation port **125'** is coupled to 3 way sub **141**. 3 way sub **141** may include port **143** which couples between the interior of 3 way sub **141** and both actuation port **125** of mechanical anchor **101'** and packer actuation port **161'**.

Actuation port **125** may, in some embodiments, be coupled to a valve assembly positioned in packer actuation port **161**. Furthermore, although not depicted, mandrel **119** may include a second coupler positioned on the end opposite coupler **117** positioned to receive an additional tubular member, allowing the tool string to extend below hydraulic anchor **101**.

FIGS. **4-11** depict a straddle packer assembly **10** including hydraulic anchor **701** being actuated via control hose **725**. Straddle packer assembly **10** may include string connection sub **20**, valve sub **30**, upper packer sub **40**, fracing sub **50**, lower packer sub **60**, and nose sub **70**.

String connection sub **20**, as depicted in FIG. **4**, may include upstream connection housing **201**. Upstream connection housing **201** is generally cylindrical and may include upstream receptacle **203** configured to couple straddle packer assembly **10** to the rest of a work string (not shown) for insertion down a borehole. Upstream receptacle **203** may be a threaded joint or any other coupling suitable for downhole string connections. Upstream connection housing **201** is configured to couple to an upper end of control tube **301** of valve sub **30** by, for example, a threaded connection, and provide a sealed connection between string connection sub bore **215** and valve sub bore **315**. Seal **303** as illustrated may assist in this seal.

Control tube **301**, as illustrated, is a generally straight-walled cylindrical tube which extends axially downward from string connection sub **20**. The lower end of control tube **301** fits into the bore of upper control housing **305**. The bore of upper control housing **305** is generally cylindrical, and at its upper end has a diameter selected to allow a clearance or sliding fit with the outer wall of control tube **301**. Outer wall of control tube **301** is fluidly sealed to the interior of upper control housing **305** by at least one seal **307**, and is permitted to slide into and out of upper control housing **305** by upward or downward loading of the work string. In some embodiments, spring **309** may be included and configured to apply compressive force between piston **311** and the upper wall of upper control housing **305**. Piston **311** is coupled to the outer wall of upstream connection housing **201** by, for example, a threaded connection. Spring **309** is illustrated as a coil spring axially disposed around control tube **301**.

Control tube **301** may include, proximal to its lower end, at least one locking feature for preventing removal from upper control housing **305**. Likewise, upper control housing **305** at its upper end may include a matching locking feature. For example, FIG. **4** illustrates control tube **301** having at least one flanged groove **313** configured to accept at least one J-pin **317**. As illustrated, as control tube **301** is pulled upward from any upward work string loading or force from spring **309**, flanged groove **313** abuts against at least one upper interior flange **319** of upper control housing **305**. J pin **317** is positioned within an internal groove that is part of upper control housing **305**. J pin **317** allows any torque applied to the work string to be transmitted through the upper control housing **305** and subsequently through the entire valve sub **30**. Upper interior flange **319** of upper control housing **305** is formed by an increase in diameter of the inner wall of upper control housing **305**. One of ordinary skill in the art will understand that this is only an exemplary configuration for preventing removal of control tube **301** from upper control housing **305**, and other technically equivalent locking feature may be employed without deviating from the scope of this disclosure.

Control tube **301** is coupled at its lower end to control tube extension **321** forming a fluidly sealed connection between the interior bore of control tube **301** and the interior bore of control tube extension **321**, here depicted as including seal **323**. Control tube extension **321** is a generally cylindrical, straight-walled tube extending downward along central axis **12**, the bore of which fluidly connecting to and forming a continuation of valve sub bore **315**.

Upper control housing **305** is coupled at its lower end to the upper end of lower control housing **325** forming a fluidly sealed connection between annular space **327** and at least one packer inflation port **329** formed in the body of lower control housing **325**. Annular space **327** is defined as the cavity formed between the outer surface of control tube **301** and/or control tube extension **321** and the inner surface of upper control housing **305**. Packer inflation port **329** continues through the rest of valve sub **30** to packer sub **40**. Lower control housing **325** is a generally cylindrical tube having a smaller inner diameter than the inner diameter of the lower end of upper control housing **305**, forming a lower interior flange **331**. Lower interior flange **331** is positioned as a means to prevent over-insertion of control tube **301**. When actuated, control tube **301** is forced downward into an "actuated position" by downward work string loading. Flanged groove **313** and J-pin **317** abut against upper surface **331**, preventing any further movement. One of ordinary skill in the art will understand that this is only an exemplary configuration for preventing overinsertion, and other technically equivalent features may be employed without deviating from the scope of this disclosure. In this example, the axial distance between upper interior flange **319** and lower interior flange **331** defines stroke length A, the distance control tube **301** is allowed to traverse between the run-in position and the actuated position.

Referring to FIG. **4**, the inner diameter of lower control housing **325** is selected to form a close clearance fit with outer wall of control tube extension **321**. Control tube extension **321** is able to traverse axially within lower control housing **325** as control tube **301** is moved.

Proximal to the upper end of control tube extension **321**, a series of apertures **333** are positioned through the wall of control tube extension **321**. Apertures **333** connect the bore of control tube extension **321** to the surrounding area. When control tube extension **321** is in the run-in position, as depicted in FIG. **4**, apertures **333** form a fluid connection between the bore of control tube **321** and annular space **327**, thereby allowing fluid a continuous connection between the bore of the work string and packer inflation port **329**. When control tube extension **321** is in the actuated position, apertures **333** are sealed off from annular space **327** by the inner diameter of lower control housing **325**. In this example, at least one seal **335** is positioned axially above the axial location of the apertures **333** in the actuated position, and at least one seal **337** is positioned axially below the axial location of the apertures **333** in the actuated position. seals **335**, **337** may be provided to assist with maintaining a seal throughout the sliding traverse of control tube extension **321**. The positioning of apertures **333** determines the cut-off characteristics of the connection between the bore of control tube **321** and annular space **327**. As depicted, apertures **333** are circular and disposed circumferentially about control tube extension **321**. One of ordinary skill in the art would understand that the number, shape, and distribution of apertures may be varied without deviating from the scope of this disclosure.

The axial distance between lower interior flange **331** and topmost extent of apertures **333** defines a packer cut-off length B, which is the distance control tube extension **321** must traverse axially downward before the fluid connection between the bore and annular space **327** is severed.

Referring now to FIG. **5**, control tube extension **321** continues axially downward within the bore of lower control housing **325**. The lower end of control tube extension **321** is coupled to the upper end of shift sleeve **339** by retainer nut **341**. In this example, retainer nut **341** is threadedly connected to the upper outer wall of shift sleeve **339**, and secures over outward flange **343** of the lower outer wall of control tube extension **321**. The upper end of shift sleeve **339** fits annularly around the lower end of control tube extension **321**. Debris barrier **345**, located in the annular interface between shift sleeve **339** and control tube extension **321**, contains at least one fluid path allowing fluid to escape the bore of shift sleeve **339** and control tube extension **321**.

Shift sleeve **339**, may be a generally cylindrical tube extending axially downward, the bore of which fluidly connecting to and forming a continuation of valve sub bore **315**. The lower end of shift sleeve **339** may include valve axle holes **347** along valve axle axis **14**. Valve axle axis **14** is coincident and orthogonal to central axis **12**. A portion of one side of the lower end of shift sleeve **339** is "cut away" along a plane parallel to central axis **12** and a plane parallel to valve axle axis **14**. At the cut away portion, shift sleeve **339** is coupled to ball seat **349**. Ball seat **349** is a generally cylindrical tube which fits within an inset of shift sleeve **339**, the bore of which fluidly connecting to and forming a continuation of valve sub bore **315**. One or more seals **351** may be used to ensure a fluid seal between ball seat **349** and shift sleeve **339**.

The lower end of ball seat **349** is adapted to closely fit against the surface of rotatable ball **353**. In at least one embodiment, the lower end of ball seat **349** is coupled to shift sleeve **339** so that ball seat **349** can move axially relative to rotatable ball **353** and shift sleeve **339** so that ball seat **349** forms sealing contact when fluid is pumped into the valve sub bore **315**. One or more seals **355** may be used to ensure there is a sufficient seal between ball seat **349** and rotatable ball **353** to reliably divert fluid to inflate the packer elements with a prescribed volumetric flow rate. Rotatable ball **353** is generally spherical with valve bore **357** through its center. Rotatable ball **353** is rotatably coupled to shift sleeve **339** by valve axle pins **359**, and may freely rotate about valve axle axis **14**. Rotatable ball **353** is positioned to rotate approximately 90° when transitioned from its run-in position, shown in FIG. **5**, to its actuated position. In the run-in position, valve bore **357** is oriented to not form a continuous fluid pathway with valve sub bore **315**. In the actuated position, control tube extension **321**, retainer nut **341**, shift sleeve **339**, ball seat **349**, and rotatable ball **353** have translated downward a distance of stroke-length A in response to downward force of control tube **301**. Rotatable ball **353** has also rotated approximately 90° about valve axle axis **14**, thereby aligning valve bore **357** with central axis **12** and allowing fluid, communication between valve sub bore **315** and valve output bore **361**.

Rotatable ball **353** in the actuated position abuts the upper edge of pressure tube **363** and forms a continuous fluid connection between valve sub bore **315** and valve output bore **361**. The top surface of pressure tube **363** forms a lower valve seat which is adapted to closely fit the surface of rotatable ball **353**.

Rotatable ball **353** is actuated by rotation pin sleeve **365**. Shift sleeve **339**, rotatable ball **353**, and rotation pin sleeve **365** are shown in detail in FIGS. **13**A-**13**B. Rotation pin sleeve **365** is shown separately in FIG. **14**. Ball seat **349** and pressure tube **363** are likewise not shown and shift sleeve **339** is in partial cross section to aid with understanding of functionality. FIG. **13**A shows the run-in configuration and FIG. **13**B shows the actuated configuration of the parts. Rotatable ball **353** is coupled to rotation pin sleeve **365** by rotation pin **367**. Rotation pin **367** extends parallel to valve axle axis **14** (not shown) and is positioned eccentrically on the surface of rotatable ball **353**. Rotation pin **367** fits into rotation window **369** formed in rotation pin sleeve **365**.

In the run-in configuration of FIG. **13**A, valve bore **357** is not aligned with central axis **12**, thereby restricting flow to valve output bore **361** (not shown), defining a "closed" position. As shift sleeve **339** and rotatable ball **353** are forced axially downward (depicted here as a translation to the right), rotation pin **367** travels axially within rotation window **369**. During the initial movement within a distance of ball seal retention length C, rotatable ball **353** remains in the closed position. Ball seal retention length C can be approximated by the following equation:

$$C=w-d_{rotation\ pin}$$

where w is the axial length of rotation window **369**, and $d_{rotation\ pin}$ is the diameter of rotation pin **367**.

Rotation pin **367** is positioned a selected distance from valve axle axis **14**, defining a rotation pin eccentricity length D. Rotation pin **367** is positioned along a line extending 45 degrees from central axis **12**. Eccentricity length D is selected such that rotatable ball **353** is rotated approximately 90° when shift sleeve **339** is moved stroke length A with a ball seal retention length C.

Once shift sleeve **339** and rotatable ball **353** have moved ball seal retention length C, rotation pin **367** contacts the wall of rotation window **369**. As shift sleeve **339** continues to move, rotatable ball **353** is rotated about valve axle axis **14** by the resultant force applied by rotation pin sleeve **365** on rotation pin **367** through the wall of rotation window **369**. As rotatable ball **353** rotates, valve bore **357** begins to open fluid communication between valve sub bore **315** and valve bore **357**, and subsequently valve output bore **361**. Ball seal retention length C is selected such that it is greater than packer cut-off length B in order to prevent fluid communication between valve sub bore **315** and valve bore **357** until after apertures **333** have seated within lower control housing **325**. Once shift sleeve **339** and rotatable ball **353** have moved stroke length A, valve bore **357** is aligned with central axis **12**, thereby allowing fluid continuous flow between valve sub bore **315** and valve output bore **361**.

Likewise, as shift sleeve **339** and rotatable ball **353** are moved axially upward, rotation pin **367** contacts the other wall of rotation window **369**. As shift sleeve **339** and rotatable ball **353** continue to move upward, the resultant force causes rotatable ball **353** to rotate back approximately 90°, thereby isolating valve sub bore **315** from valve output bore **361** and returning to its run-in configuration. Geometry of rotation window **369** is selected such that rotatable ball **353** remains at least partially open when apertures **333** are opened to annular space **327**.

Referring back to FIG. **5**, valve operating chamber **371** is defined by the inner wall of lower control housing **325**, rotatable ball **353** and shift sleeve **339**, and pressure tube **363** and rotation pin sleeve **365**. As shift sleeve **339** and rotatable ball **353** are shifted into the actuated position, valve operating chamber **371** decreases in volume. Any trapped fluid is permitted to return to valve sub bore **315** from operating chamber **371** through grooves (not shown) in debris barrier **345**.

Lower end of lower control housing **325** is coupled to the upper end of crossover housing **373**. Crossover housing **373** may include at least one port formed in its wall to form a continuation of packer inflation port **329**. Crossover housing **373** is a generally cylindrical tube extending downward along central axis **12**. Crossover housing **373** is depicted as threadedly coupled to control housing **325**. Pressure tube **363** is coupled within the upper bore of crossover housing **373**. Continuing to FIG. **6**, crossover housing **373** is coupled to upper packer sub **40**.

Upper packer sub **40** is a generally cylindrical tube, including upper packer mandrel **401** having upper packer bore **403** fluidly connected to valve output bore **361**. Upper packer sub **40** is configured to allow fluid to flow from packer inflation port **329** to the interior of upper packer **405**. Upper packer sub **40** may include upper ring **407** which is threadedly connected to downwardly and inwardly tapered member **409**, thereby compressively sealing the end of upper packer **405** against the interior of upper packer housing **411**. Holes in upper ring **407** pass fluid from packer inflation port **329** to the interior of upper packer **405**. Upper packer **405** may include upper packer inner layer **413** and upper packer outer layer **415**, both depicted as elastomeric material, and an upper and lower metal packer shield **417**, **419**. Upper and lower metal packer shields **417**, **419** may be configured to control the inflation of upper packer **405**.

FIG. **7** depicts the lower end of upper packer sub **40**, including lower ring **421** which is threadedly connected to upwardly and inwardly tapered member **423**, compressing the end of upper packer **405** against the interior of lower packer housing **425**. Holes in lower ring **421** allow fluid to pass from upper packer **405** to upper packer bottom housing **427**, which may include upper packer hose connector **429**. Upper packer hose connector **429** allows fluid to pass from upper packer bottom housing **427** through hose **501**, which fluidly connects to lower packer sub **60**. Upper packer bottom housing **427** may also include at least one seal **431** to isolate fluid in the wellbore from fluid used to inflate the packers.

Continuing to FIGS. **8-10**, upper packer mandrel **401** continues axially downward and couples to at least one fracing mandrel **503**. Fracing mandrel **503** has fracing sub bore **505** fluidly connected to upper packer bore. Fracing mandrel **503** may include one or more fracing apertures **507** which connects fracing sub bore **505** with the wellbore surrounding fracing mandrel **503**, thereby allowing for hydraulic fracturing of a surrounding formation (not shown). The exemplary embodiment shown by the figures may include multiple lengths of pipe to make up fracing mandrel **503**. The displayed configuration of fracing mandrel **503**, including, for example, number of pipes, length of pipe sections, overall length, and configuration of pipe, will be understood by one of ordinary skill in the art to be only an example, and any reconfiguration would not deviate from the scope of this disclosure. Likewise, the configuration of fracing apertures **507**, including, for example, number, shape, and positioning of fracing apertures, will be understood by one of ordinary skill in the art to be only an example, and any reconfiguration would not deviate from the scope of this disclosure.

Hose **501** is shown continuing downward through the well bore, having various fittings and configurations to, for example, secure additional lengths of hose, couple hose **501** to fracing mandrel **503**, allow strain relief, etc. One of ordinary skill in the art will readily understand that the configuration shown in the figures is meant only as an example, and any reconfiguration would not deviate from the scope of this disclosure.

Fracing mandrel **503** couples, at its lower end, to upper end of lower packer sub **60**, here shown as threadedly connected to lower packer top housing **627**. Lower packer top housing **627** may include lower packer bore **603** fluidly connected to fracing sub bore **505**. Lower packer top housing **627** is coupled at its lower end to the upper end of lower packer mandrel **601**, the bore of which fluidly connected to and forming an extension of lower packer bore **603**.

Lower packer top housing **627** may also include lower packer hose connector **629** which is coupled to hose **501** and allows fluid to pass from hose **501** to lower packer sub **60**, thereby connecting upper packer sub **40** to lower packer sub **60**. Fluid from hose **501** can pass through at least one inflation port **631** to the interior of lower packer **605**.

Referring to FIGS. **10**, **11**, lower packer sub **60** may include upper ring **607** which is threadedly connected to downwardly and inwardly tapered member **609**, thereby compressively sealing the end of lower packer **605** against the interior of upper packer housing **611**. Holes in upper ring **607** pass fluid from inflation port **631** to the interior of lower packer **605**. Lower packer **605** may include lower packer inner layer **613** and lower packer outer layer **615**, both depicted as elastomeric material, and at least one upper and lower metal packer shield **617**, **619**. Upper and lower metal packer shields **617**, **619** may be configured to control the inflation of upper packer **605**. The lower end of lower packer sub **60**, may include lower ring **621** which is threadedly connected to upwardly and inwardly tapered member **623**, compressing the end of lower packer **605** against the interior of lower packer housing **625**. Here, lower packer sub **60** is shown to have a lower packer bottom housing **633** including at least one seal **635** to isolate fluid in the wellbore from fluid used to inflate the packers.

Lower end of lower packer mandrel **601** is coupled to hydraulic anchor **701**. Hydraulic anchor **701** is positioned to be actuated by control hose **725** coupled to lower packer control hose connector **637**. Control hose **725** is coupled to actuation cylinder **721**. Thus, once valve sub **30** is actuated, upper packer sub **40**, lower packer sub **60**, and hydraulic anchor **701** are all actuated by the same fluid pressure. In some embodiments, hydraulic anchor **701** may provide anchoring between straddle packer assembly **10** and the surrounding wellbore or tubular to, for example, allow force applied by the tool string to press down against control tube **301**. Additionally, hydraulic anchor **701** may include mandrel **719** which, in such an embodiment, may be a tubular member having no apertures. In some embodiments, hydraulic anchor **701** may include a lower connector **741** allowing, for example, the connection of a tubular member below hydraulic anchor **701**.

In other embodiments, as depicted in FIG. **16**, hydraulic anchor **801** may instead be used with a swellable packer **851**. Swellable packer may include a swellable packer mandrel **855**. Positioned about swellable packer mandrel **855** is swellable elastomeric body **853** which increases in volume in response to the absorption of a swelling fluid, generally an oil or water-based fluid. The composition of the swelling fluid needed to activate swellable packer elements **105** may be selected with consideration of the conditions of the wellbore. Once activated, the swelling fluid comes into contact with swellable elastomeric body **853** and is absorbed by the elastomeric material. In response to the absorption of swelling fluid, swellable elastomeric body increases in volume and eventually contacts the surrounding wellbore or tubular. Continued swelling of swellable elastomeric body **853** may form a seal between swellable packer mandrel **855** and the surrounding wellbore or tubular. The fluid seal may serve to prevent any high-pressure fluids which may be encountered during the life of the wellbore from escaping around swellable packer **851**.

In operation, swellable packer **851** and hydraulic anchor **801** are positioned in the wellbore. As previously discussed, fluid pressure actuates hydraulic anchor **801**, holding swellable packer **851** in position within the wellbore during the time it takes for swellable packer **851** to fully expand and create the seal. In some embodiments, a valve (not shown) may be positioned within mechanical anchor **801** to cause mechanical anchor **801** to permanently remain in the engaged position once pressure inside actuation port **825** is bled. In some embodiments, a mechanical retainer (not shown) may be positioned within actuation cylinder to retain mechanical anchor **801** in the engaged position with extendible arm **809** in the extended position once extended. One having ordinary skill in the art with the benefit of this disclosure will understand that any such mechanical retainer mechanism may be used, including without limitation, a spring-loaded pawl, ratchet system, etc. may be utilized without deviating from the scope of this disclosure. With mechanical anchor **801** retained in the open position, the tool string used to position swellable packer **851** within the wellbore may thus be removed, leaving swellable packer **851** within the wellbore while it expands and, for example, to seal against the wellbore.

The foregoing outlines features of several embodiments so that a person of ordinary skill in the art may better understand the aspects of the present disclosure. Such features may be replaced by any one of numerous equivalent alternatives, only some of which are disclosed herein. One of ordinary skill in the art should appreciate that they may readily use the present disclosure as a basis for designing or modifying other processes and structures for carrying out the same purposes and/or achieving the same advantages of the embodiments introduced herein. One of ordinary skill in the art should also realize that such equivalent constructions do not depart from the spirit and scope of the present disclosure and that they may make various changes, substitutions and alterations herein without departing from the spirit and scope of the present disclosure.

The invention claimed is:

1. A downhole tool for use within a wellbore, the downhole tool comprising:

a hydraulic anchor, the hydraulic anchor including:

- a tool body, the tool body including a generally cylindrical mandrel, the tool body including a coupler positioned to allow the tool body to couple to a tubular member, the mandrel having an interior;
- a stroking sleeve, the stroking sleeve being generally tubular, the stroking sleeve positioned to slide along the mandrel of the tool body;
- an actuation cylinder, the actuation cylinder formed between the stroking sleeve and the tool body, the actuation cylinder fluidly coupled to the interior of the mandrel;
- an extendible arm, the extendible arm including a grip plate, a first extension linkage, and a second extension linkage, the first extension linkage pivotably coupled between the tool body and the grip plate, and the second extension linkage pivotably coupled between the grip plate and the stroking sleeve;

an inflatable packer, the inflatable packer including:

- a packer mandrel, the packer mandrel having an interior in fluid communication with the interior of the mandrel of the tool body;
- a packer bladder, the packer bladder being generally tubular in shape and positioned about the packer mandrel; and
- a packer inflation port, the packer inflation port formed in the packer mandrel, the packer inflation port positioned to couple the interior of the packer mandrel with an annular space between the packer mandrel and the packer bladder.

2. The downhole tool of claim **1**, further comprising:
a rupture disc positioned in fluid communication with the actuation cylinder and the wellbore, the rupture disc adapted to mechanically fail when fluid pressure within the actuation cylinder reaches a threshold pressure.

3. The downhole tool of claim **1**, further comprising:
a spring positioned to bias the stroking sleeve to a run-in position, the run-in position defined as the position at which the extendible arm is fully retracted.

4. The downhole tool of claim **1**, wherein the tool body further comprises a lower sub, the lower sub coupled to the mandrel.

5. The downhole tool of claim **1**, further comprising:
a second inflatable packer, the second inflatable packer including:
a second packer mandrel, the second packer mandrel having an interior;
a second packer bladder, the second packer bladder being generally tubular in shape and positioned about the second packer mandrel;
a second packer inflation port, the packer inflation port formed in the packer mandrel, the second packer inflation port positioned to couple the interior of the second packer mandrel with a second annular space between the second packer mandrel and the second packer bladder; and
a perforated sub, the perforated sub including a perforated sub mandrel, the perforated sub mandrel including at least one selectively actuatable aperture positioned between the interior of the perforated sub mandrel and the wellbore, the perforated sub mandrel having a first and second end, the first end coupled to the first inflatable packer, and the second end coupled to the second inflatable packer.

6. The downhole tool of claim **1**, wherein the actuation cylinder is fluidly coupled to the interior of the mandrel via a port formed in the mandrel.

7. The downhole tool of claim **1**, further comprising a generally tubular three-way sub positioned between the tool body and the packer mandrel, the three-way sub including a port formed in a wall of the three-way sub positioned to fluidly couple an interior of the three-way sub to the actuation cylinder and the packer inflation port.

8. The downhole tool of claim **1**, wherein the actuation cylinder is fluidly coupled to the interior of the mandrel via a control hose.

9. The downhole tool of claim **1**, wherein the hydraulic anchor further comprises a valve positioned to retain the pressure within the actuation cylinder after fluid pressure is bled from the interior of the mandrel.

10. The downhole tool of claim **1**, wherein the hydraulic anchor further comprises a mechanical retainer positioned to permanently retain the extendible arm in an extended position once the extendible arm is extended.

11. A downhole tool for use within a wellbore, the downhole tool comprising:
a hydraulic anchor, the hydraulic anchor including:
a tool body, the tool body including a generally cylindrical mandrel, the tool body including a coupler positioned to allow the tool body to couple to a tubular member, the mandrel having an interior;
a stroking sleeve, the stroking sleeve being generally tubular, the stroking sleeve positioned to slide along the mandrel of the tool body;
an actuation cylinder, the actuation cylinder formed between the stroking sleeve and the tool body, the actuation cylinder fluidly coupled to the interior of the mandrel;
an extendible arm, the extendible arm including a grip plate, a first extension linkage, and a second extension linkage, the first extension linkage pivotably coupled between the tool body and the grip plate, and the second extension linkage pivotably coupled between the grip plate and the stroking sleeve;
a swellable packer, the swellable packer including:
a packer mandrel, the packer mandrel having an interior in fluid communication with the interior of the mandrel of the tool body, the packer mandrel coupled to the tool body; and
an elastomeric swellable body, the elastomeric swellable body being generally tubular in shape and positioned about the packer mandrel.

12. The downhole tool of claim **11**, further comprising:
a rupture disc positioned in fluid communication with the actuation cylinder and the wellbore, the rupture disc adapted to mechanically fail when fluid pressure within the actuation cylinder reaches a threshold pressure.

13. The downhole tool of claim **11**, further comprising:
a spring positioned to bias the stroking sleeve to a run-in position, the run-in positioned defined as the position at which the extendible arm is fully retracted.

14. The downhole tool of claim **11**, wherein the tool body further comprises a lower sub, the lower sub coupled to the mandrel.

15. The downhole tool of claim **11**, wherein the actuation cylinder is fluidly coupled to the interior of the mandrel via a port formed in the mandrel.

16. The downhole tool of claim **11**, wherein the hydraulic anchor further comprises a valve positioned to retain the pressure within the actuation cylinder after fluid pressure is bled from the interior of the mandrel.

17. The downhole tool of claim **11**, wherein the hydraulic anchor further comprises a mechanical retainer positioned to permanently retain the extendible arm in an extended position once the extendible arm is extended.

18. A method comprising:
positioning a tool string within a wellbore, the tool string including:
a hydraulic anchor, the hydraulic anchor including:
a tool body, the tool body including a generally cylindrical mandrel, the tool body including a coupler positioned to allow the tool body to couple to a tubular member, the mandrel having an interior;
a stroking sleeve, the stroking sleeve being generally tubular, the stroking sleeve positioned to slide along the mandrel of the tool body;
an actuation cylinder, the actuation cylinder formed between the stroking sleeve and the tool body, the actuation cylinder fluidly coupled to the interior of the mandrel;
an extendible arm, the extendible arm including a grip plate, a first extension linkage, and a second extension linkage, the first extension linkage pivotably coupled between the tool body and the grip plate, and the second extension linkage pivotably coupled between the grip plate and the stroking sleeve;
a swellable packer, the swellable packer including:
a packer mandrel, the packer mandrel having an interior in fluid communication with the interior of the mandrel of the tool body, the packer mandrel coupled to the tool body;

an elastomeric swellable body, the elastomeric swellable body being generally tubular in shape and positioned about the packer mandrel;

applying fluid pressure to the actuation cylinder;

extending the extendible arm, the extendible arm contacting the surrounding wellbore; and

exposing the elastomeric swellable body to a swelling fluid, the elastomeric swellable body increasing in volume to form a seal between the packer mandrel and the wellbore.

19. The method of claim **18**, further comprising:

disconnecting the tool string from the swellable packer so that the swellable packer and hydraulic anchor remain in the wellbore;

removing the tool string from the wellbore.

20. A method comprising:

positioning a tool string within a wellbore, the tool string including:

a hydraulic anchor, the hydraulic anchor including:

a tool body, the tool body including a generally cylindrical mandrel, the tool body including a coupler positioned to allow the tool body to couple to a tubular member, the mandrel having an interior;

a stroking sleeve, the stroking sleeve being generally tubular, the stroking sleeve positioned to slide along the mandrel of the tool body;

an actuation cylinder, the actuation cylinder formed between the stroking sleeve and the tool body, the actuation cylinder fluidly coupled to the interior of the mandrel;

an extendible arm, the extendible arm including a grip plate, a first extension linkage, and a second extension linkage, the first extension linkage pivotably coupled between the tool body and the grip plate, and the second extension linkage pivotably coupled between the grip plate and the stroking sleeve; and

an inflatable packer, the inflatable packer including:

a packer mandrel, the packer mandrel having an interior in fluid communication with the interior of the mandrel of the tool body;

a packer bladder, the packer bladder being generally tubular in shape and positioned about the packer mandrel; and

a packer inflation port, the packer inflation port formed in the packer mandrel, the packer inflation port positioned to couple the interior of the packer mandrel with an annular space between the packer mandrel and the packer bladder;

applying fluid pressure to the actuation cylinder;

extending the extendible arm, the extendible arm contacting the surrounding wellbore;

applying fluid pressure to the packer inflation port; and

inflating the inflatable packer.

21. A downhole tool on a tool string having a tool string bore positionable in a wellbore having a wellbore axis, the downhole tool comprising:

a first packer sub coupled to the tool string, the packer sub having a first inflatable element and a first packer inflation port;

a valve sub coupled to the tool string, the valve sub having:

a valve sub housing, the valve sub housing being generally tubular having at least one packer supply port in fluid communication with the packer inflation port;

a control tube, the control tube being generally tubular and aligned with the valve sub housing and having an upper and lower end, the upper end coupled to the tool string, and the lower end positioned within the bore of the valve sub housing, the control tube having a bore and at least one aperture through its side wall, the control tube having an open position in which the aperture provides fluid communication between the bore of the control tube and the packer supply port, and a closed position in which the apertures are covered by the inner wall of the valve sub housing and the bore of the control tube, the control tube bore being in fluid communication with the tool string bore;

a shift sleeve coupled to the lower end of the control tube having a hole adapted to accept an axle pin;

a rotatable ball adapted to rotate about the axle pin, the rotatable ball having at least one flow path through its body, the rotatable ball having an open position and a closed position selected by the upward or downward movement of the tool string, the open and closed positions of the rotatable ball being in opposition to the open and closed position of the control tube, thereby allowing or preventing fluid flow through the at least one flow path from the tool string bore and the bore of the control tube, the rotatable ball having a rotation pin extending from its outer surface; and

a rotation pin sleeve coupled to the rotation pin adapted to rotate the ball from the closed position to the open position in response to a movement of the ball toward or away from the rotation pin sleeve;

a hydraulic anchor, the hydraulic anchor including:

a tool body, the tool body including a generally cylindrical mandrel, the tool body including a coupler positioned to allow the tool body to couple to a tubular member, the mandrel having an interior in fluid communication with the interior of the mandrel of the tool body;

a stroking sleeve, the stroking sleeve being generally tubular, the stroking sleeve positioned to slide along the mandrel of the tool body;

an actuation cylinder, the actuation cylinder formed between the stroking sleeve and the tool body, the actuation cylinder fluidly coupled to the interior of the mandrel; and

an extendible arm, the extendible arm including a grip plate, a first extension linkage, and a second extension linkage, the first extension linkage pivotably coupled between the tool body and the grip plate, and the second extension linkage pivotably coupled between the grip plate and the stroking sleeve.

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