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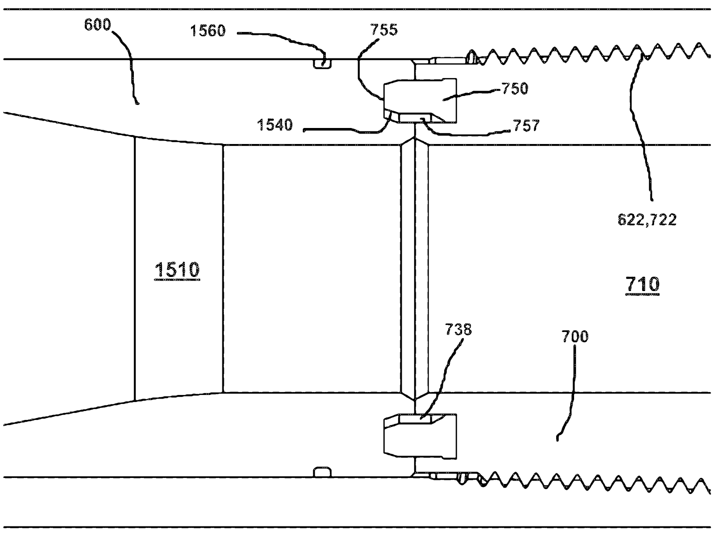

FIG. 11B

(57) **Abstract**: What is provided is a method and apparatus wherein a rotating and reciprocating swivel of adjustable stroke length and shearable by ram blow out preventers can be detachably connected to an annular blowout preventer thereby separating the lower wellbore from the riser. In one embodiment the mandrel of the swivel being comprised of double box end joints and using double pin end subs to connect a plurality of such mandrel joints together.

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PCT PATENT APPLICATION

TITLE

ROTATING AND RECIPROCATING SWIVEL APPARATUS AND METHOD

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CROSS-REFERENCE TO RELATED APPLICATIONS

This is a non-provisional of United States provisional patent application serial number 61/620,207, filed 4 April 2012, which is incorporated herein by reference and priority of/to which is hereby claimed.

United States Patent Application serial number 12/682,912, entitled Rotating And Reciprocating Swivel Apparatus and Method, having a 20 September 2010 filing or section 371(c) date, is hereby incorporated herein by reference.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

Not applicable

REFERENCE TO A "MICROFICHE APPENDIX"

Not applicable

BACKGROUND

In deepwater drilling rigs, marine risers extending from a wellhead fixed on the ocean floor have been used to circulate drilling fluid or mud back to a structure or rig. The riser must be large enough in internal diameter to accommodate a drill string or well string that includes the largest bit and drill pipe that will be used in drilling a borehole. During the drilling process drilling fluid or mud fills the riser and wellbore.

BRIEF SUMMARY

The method and apparatus of the present invention solves the problems confronted in the art in a simple and straightforward manner.

One embodiment relates to a method and apparatus for deepwater rigs. In particular, one embodiment relates to a method and apparatus for performing downhole operations at a time when the annular blow out preventer is closed.

In one embodiment displacement is contemplated in water depths in excess of about 5,000 feet (1,524 meters).

One embodiment provides a method and apparatus having a swivel which can operably and/or detachably connect to an annular blowout preventer thereby separating the fluid or mud into upper and lower sections.

In one embodiment a swivel tool can be used having a sleeve or housing that is rotatably and sealably connected to a mandrel. The swivel can be incorporated into a drill or well string.

In one embodiment the sleeve or housing can be fluidly sealed to and/or from the mandrel.

In one embodiment the sleeve or housing can be fluidly sealed with respect to the outside environment.

In one embodiment the sealing system between the sleeve or housing and the mandrel is designed to resist fluid infiltration from the exterior of the sleeve or housing to the interior space between the sleeve or housing and the mandrel.

In one embodiment the sealing system between the sleeve or housing and the mandrel is designed to resist fluid infiltration from the interior space between the sleeve or housing and the mandrel to the exterior.

In one embodiment the sealing system between the sleeve or housing and the mandrel has a substantially equal pressure ratings for pressures tending to push fluid from the exterior of the sleeve or housing to the interior space between the sleeve or housing and the mandrel and pressures tending to push fluid from the interior space between the sleeve or housing and the mandrel to the exterior of the sleeve or housing.

In one embodiment a swivel having a sleeve or housing and mandrel is used having at least one flange, catch, or upset to restrict longitudinal movement of the sleeve or housing relative to the annular blow out preventer. In one embodiment a plurality of flanges, catches, or upsets are used. In one embodiment the plurality of flanges, catches, or upsets are longitudinally spaced apart with respect to the sleeve or housing.

The swivel tool can be closed on by the annular blowout preventer ("annular BOP"). Typically, the annular BOP is located immediately above the ram BOP which ram BOP is located immediately above the sea floor and mounted on the well head. As an integral part of the string, the mandrel of the rotating and reciprocating tool supports the full weight, torque, and pressures of the entire string located below the mandrel.

In one embodiment, at least partly during the time the annular seal is closed on the sleeve of the swivel, the drill or well string is intermittently stroked longitudinally during downhole operations, such as in a hydraulic fracturing job.

In one embodiment the rotational speed is reduced during the time periods that reciprocation is not being performed. In one embodiment the rotational speed is reduced from about 60 revolutions per minute to about 30 revolutions per minute when reciprocation is not being performed.

In one embodiment, at least partly during the time the annular seal is closed on the sleeve of the swivel, the drill or well string is reciprocated longitudinally. In one embodiment a reciprocation stroke of about 65.5 feet (20 meters) is contemplated. In one embodiment about 20.5 feet (6.25 meters) of the stroke is contemplated for allowing access to the bottom of the well bore. In one embodiment about 35, about 40, about 45, and/or about 50 feet (about 10.67, about 12.19, about 13.72, and/or about 15.24 meters) of the stroke is contemplated for allowing at least one pipe joint-length of stroke during reciprocation. In one embodiment reciprocation is performed up to a speed of about 20 feet per minute (6.1 meters per minute).

In one embodiment one or more brushes and/or scrapers are used in the method and apparatus.

In one embodiment a mule shoe is used in the method and apparatus.

Catches

The annular BOP is designed to fluidly seal on a large range of different sized items - - e.g., from 0 inches to 18 3/4 inches (0 to 47.6 centimeters) (or more). However, when an annular BOP fluid seals on the sleeve of the rotating and reciprocating tool, fluid pressures on the sleeve's exposed effective cross sectional area exert longitudinal forces on the sleeve. These longitudinal forces are the product of the fluid pressure on the sleeve and the sleeve's effective cross sectional area. Where different pressures exist above and below the annular BOP (which can occur in completions having multiple stages), a net longitudinal force will act on the sleeve tending to push it in the direction of the lower fluid pressure. If the differential pressure is large, this net longitudinal force can overcome the frictional force applied by the closed annular BOP on the sleeve and the frictional forces between the sleeve and the mandrel. If these frictional forces are overcome, the sleeve will tend to slide in the direction of the lower pressure and can be "pushed" out of the closed annular BOP. In one embodiment catches are provided which catch onto the annular BOP to prevent the sleeve from being pushed out of the closed annular BOP.

For example, lighter sea water above the annular BOP seal and heavier drilling mud, or weighted pills, and/or weighted completion fluid, or a combination of all of these can be below the annular BOP requiring an increased pressure to push such fluids from below the annular BOP up through the choke line and into the rig (at the selected flow rate). This pressure differential (in many cases causing a net upward force) acts on the effective cross sectional area of the tool defined by the outer diameter of the string (or mandrel) and the outer diameter of the sleeve. For example, the outer sealing diameter of the tool sleeve can be 9 3/4 inches (24.77 centimeters) and the outer diameter of the tool mandrel can be 7 inches (17.78 centimeters) providing an annular cross sectional area of 9 3/4 inches (24.77 centimeters) OD and 7 inches ID (17.78 centimeters). Any differential pressure will act on this annular area producing a net force in the direction of the pressure gradient equal to the pressure differential times the effective cross sectional area. This net force produces an upward force which can overcome the frictional force applied by the annular BOP closed on the tool's sleeve causing the sleeve to be pushed in the direction of the net force (or slide through the sealing element of the annular BOP). To resist sliding through the annular BOP, catches can be placed on the sleeve which prevent the sleeve from being pushed through the annular BOP seal.

In any of the various embodiments, the following differential pressures (e.g., difference between the pressures above and below the annular BOP seal) can be axially placed upon the sleeve or housing against which the catches can be used to prevent the sleeve from being axially pushed out of the annular BOP (even when the annular BOP seal has been closed) - - in pounds per square inch: 500, 750, 1000, 1250, 1500, 1750, 2000, 2250, 2500, 2750, 3000, 3250, 3,500, 3750, 4,000, 4,250, 4,500, 4,750, 5,000, 10,000 or greater (3,450, 5,170, 6,900, 8,620, 10,340, 12,070, 13,790, 15,510, 17,240, 18,960, 20,690, 22,410, 24,130, 25,860, 27,700, 29,550, 31,400, 33,240, 35,090, 36,940, 73,880 kilopascals). Additionally, ranges between any two of the above specified pressures are contemplated. Additionally, ranges above any one of the above specified pressures are contemplated. Additionally, ranges below any one of the above specified pressures are contemplated. These differential pressures can be higher below the annular BOP seal or above the annular BOP seal.

Quick Lock/Quick Unlock

After the sleeve and mandrel have been moved relative to each other in a longitudinal direction, a downhole/underwater locking/unlocking system is needed to lock the sleeve in a longitudinal position relative to the mandrel (or at least restricting the available relative longitudinal movement of the sleeve and mandrel to a satisfactory amount compared to the longitudinal length of the sleeve's effective sealing area). Additionally, an underwater locking/unlocking system is needed which can lock and/or unlock the sleeve and mandrel a plurality of times while the sleeve and mandrel are underwater.

In one embodiment is provided a system wherein the underwater position of the longitudinal length of the sleeve's sealing area (e.g., the nominal length between the catches) can be determined with enough accuracy to allow positioning of the sleeve's effective sealing area in the annular BOP for closing on the sleeve's sealing area. After the sleeve and mandrel have been longitudinally moved relative to each other when the annular BOP was closed on the sleeve, it is preferred that a system be provided wherein the underwater position of the sleeve can be determined even where the sleeve has been moved outside of the annular BOP.

In one embodiment is provided a quick lock/quick unlock system for locating the relative position between the sleeve and mandrel. Because the sleeve can reciprocate relative to the mandrel (i.e., the sleeve and mandrel can move relative to each other in a longitudinal direction), it can be important to be able to determine the relative longitudinal position of the sleeve compared to the mandrel at some point after the sleeve has been reciprocated relative to the mandrel. For example, in various uses of the rotating and reciprocating tool, the operator may wish to seal the annular BOP on the sleeve sometime after the sleeve has been reciprocated relative to the mandrel and after the sleeve has been removed from the annular BOP.

To address the risk that the actual position of the sleeve relative to the mandrel will be lost while the tool is underwater, a quick lock/quick unlock system can detachably connect the sleeve and mandrel. In a locked state, this quick lock/quick unlock system can reduce the amount of relative longitudinal movement between the sleeve and the mandrel (compared to an unlocked state) so that the sleeve can be positioned in the annular BOP and the annular BOP relatively easily closed on the sleeve's longitudinal sealing area. Alternatively, this quick lock/quick unlock system can lock in place the sleeve relative to the mandrel (and not allow a limited amount of relative longitudinal movement). After being changed from a locked state to an unlocked state, the sleeve can experience its unlocked amount of relative longitudinal movement.

In one embodiment is provided a quick lock/quick unlock system which allows the sleeve to be longitudinally locked and/or unlocked relative to the mandrel a plurality of times when underwater. In one embodiment the quick lock/quick unlock system can be activated using the annular BOP.

In one embodiment the sleeve and mandrel can rotate relative to one another even in both the activated and un-activated states. In one embodiment, when in a locked state, the sleeve and mandrel can rotate relative to each other. This option can be important where the annular BOP is closed on the sleeve at a time when the string (of which the mandrel is a part) is being rotated. Allowing the sleeve and mandrel to rotate relative to each other, even when in a locked state, minimizes wear/damage to the annular BOP caused by a rotationally locked sleeve (e.g., sheer pin) rotating relative to a closed annular BOP. Instead, the sleeve can be held fixed rotationally by the closed annular BOP, and the mandrel (along with the string) rotates relative to the sleeve.

In one embodiment, when the locking system of the sleeve is in contact with the mandrel, locking/unlocking is performed without relative rotational movement between the locking system of the sleeve and the mandrel - - otherwise scoring/scratching of the mandrel at the location of lock can occur. In one embodiment, this can be accomplished by rotationally connecting to the sleeve the sleeve's portion of quick lock/quick unlock system. In one embodiment a locking hub is provided which is rotationally connected to the sleeve.

In one embodiment a quick lock/quick unlock system on the rotating and reciprocating tool can be provided allowing the operator to lock the sleeve relative to the mandrel when the rotating and reciprocating tool is downhole/underwater. Because of the relatively large amount of possible stroke of the sleeve relative to the mandrel (i.e., different possible relative longitudinal positions), knowing the relative position of the sleeve with respect to the mandrel can be important. This is especially true at the time the annular BOP is closed on the sleeve. The locking position is important for determining relative longitudinal position of the sleeve along the mandrel (and therefore the true underwater depth of the sleeve) so that the sleeve can be easily located in the annular BOP and the annular BOP closed /sealed on the sleeve.

During the process of moving the rotating and reciprocating tool underwater and downhole, the sleeve can be locked relative to the mandrel by a quick lock/quick unlock system. In one embodiment the quick lock/quick unlock system can, relative to the mandrel, lock the sleeve in a longitudinal direction. In one embodiment the sleeve can be locked in a longitudinal direction with the quick lock/quick unlock system, but the sleeve can rotate relative to the mandrel during the time it is locked in a longitudinal direction. In one embodiment the quick lock/quick unlock system can simultaneously lock the sleeve relative to the mandrel, in both a longitudinal direction and rotationally. In one embodiment the quick lock/quick unlock system can, relative to the mandrel, lock the sleeve rotationally, but at the same time allow the sleeve to move longitudinally.

General Embodiments

In one embodiment the mandrel is comprised of a plurality of joints of piping/tubing which are threadably connected to each other.

In one embodiment a sleeve/housing is rotatably and slidably connected to the mandrel.

In one embodiment the sleeve/housing includes a pair of spaced apart sealing units which sealingly engage the sleeve/housing relative to the external surface of the mandrel during the time period the sleeve is slidably and/or rotatably connected to the mandrel.

In one embodiment the sleeve/housing can remain stationary while a portion of the mandrel is moved longitudinally or stroked relative to the sleeve.

In one embodiment the mandrel can be stroked or passed through the reciprocable and rotatable sleeve/housing while the sleeve/housing is maintained stationary relative to an annular blow out preventer, and with the annular blow out preventer maintaining a seal on the sealing area of the sleeve/housing. With the seal between the sleeve/housing and the mandrel, in combination with the seal between the annular of the annular blow out preventer and the sealing area of the sleeve, a fluid seal can be maintained between above and below the annular seal of the annular blow out preventer even when the mandrel is stroked and/or rotating. Such allows any drill string, tools, and/or other items located below the mandrel to be rotated and/or reciprocated while the closed annular blow out preventer maintains a seal on the wellbore, and without the annular seal of the annular blowout preventer being subjected to differential movement which differential movement can damage the annular seal.

One embodiment allows the stroking area of the mandrel to slide relative to the sleeve/housing, thereby providing the benefit of longitudinal movement and/or rotation but substantially eliminating differential movement of any item in contact with the closed annular sealing element relative to the closed annular sealing element. Accordingly, the risk of damage to the closed annular sealing element is substantially eliminated.

Shearable mandrel design

One embodiment provides a downhole swivel tool comprising a longitudinal mandrel with a longitudinal interior passageway, the mandrel having a sleeve/housing slidably connected to the mandrel, wherein the mandrel can rotate and reciprocate/stroke relative to the sleeve, and wherein sleeve/housing and the mandrel is sealed in a longitudinal direction.

There is a long felt but unsolved need to have a swivel tool including a mandrel that is shearable relative to a plurality of stacked ram type blow out preventers regardless of the position of the mandrel relative to the stack of ram type blow out preventers.

In one embodiment, within the stroking length of the mandrel, the exterior mandrel sealing surface can be kept substantially at a uniform diameter to maintain a longitudinal seal with respect to the sleeve/housing.

One embodiment of the swivel tool provides a mandrel, within the stroking length of the mandrel, the exterior mandrel sealing surface being kept at a substantially uniform diameter to maintain a longitudinal seal with respect to the sleeve/housing, within this stroking length the mandrel having a interior axial passageway, the interior axial passageway having first and second diameters, the first diameter being larger than the second diameter, with the longitudinal spacing of the sections of mandrel having first diameter to sections having second diameter being such that at any one point at least one ram of a plurality of stacked ram blow out preventers would attempt to shear a section of the mandrel having the first diameter thereby ensuring continuous shearability of the mandrel.

In one embodiment the exterior sealing surface of the mandrel can have one or more recessed areas. In one embodiment the sleeve/housing can have a plurality of spaced apart sealing units, such that at any one time during stroking/rotation of the mandrel relative to the sleeve at least one of the spaced apart sealing units maintains a seal between the mandrel and the sleeve even when the other sealing unit is located above a recessed area of the mandrel.

In one embodiment the one or more recessed areas can be used to vertically support the mandrel when making up or breaking out the mandrel when at a rig bore.

In one embodiment the one or more recessed areas can be located on pin/male by pin/male joints of mandrel which pin/male by pin/male pin joints have a larger wall thickness relative to the wall thickness of the box/female by box/female joints of mandrel.

In one embodiment the smallest diameter of the one or more recessed areas can be between the diameter of the axial passage through the pin/male by pin/male joint and the axial diameter of the axial passage of the box/female by box/female joint.

In one embodiment the mandrel is constructed of multiple joints of box/female to box/female ends having thin walled tubing/piping meeting predefined shearing constraints for a specified ram type blow out preventer.

Because of manufacturing ease, typically the longitudinal passage through a joint of tubular is substantially the same size.

In detachably threaded connections (e.g., male and female threads) for joints of tubulars, the male portion of the connection being concentric with the female portion of the connection, with the male portion being interior to the female portion of such connection, the largest longitudinal passage through the male portion of such connection is necessarily smaller than the largest longitudinal passage through the female portion of the connection.

With a joint of tubular having a pin/male by box/female end, the largest possible size of longitudinal axial passage is controlled by the size of the smaller interiorly concentric pin end connection. With a joint of tubular having a box/female by box/female end connection, now the largest possible size of longitudinal passage is controlled by the size of the exteriorly concentric box/female end connection, and can be larger than the size of a mating interiorly concentric pin/male end connection.

Now a mandrel formed by such combination of joints of box/female by box/female end joints alternatively connected by pin/male by pin/male end joints of tubular can have spaced apart thin walled portions that are easily shearable by ram type blow out preventers. The spacing apart of the thin walled portions can be on opposing sides of the pin/male by pin/male joints of mandrel. The alternative box/female by box/female with pin/male by pin/male can have length spacings such that at any one point at least one ram of the plurality of stacked ram blow out preventers would attempt to shear a thin walled portion of the mandrel thereby ensuring continuous shearability of the mandrel.

The mandrel can comprise one or more joints of tubing or piping with box/female by box/female ends and each joint being approximately 30 feet in length.

Connecting the box/female by box/female ended joints of tubing/piping can be joints of pipe which are pin/male by pin/male type connections, with each of these pin by pin joints being approximately 30 inches in length.

The mandrel stroking area can include a longitudinal length of combined plurality of mandrel joints where such joints have a substantially uniform outer sealing diameter.

Threading can be used to detachably connect the mandrel joints to each other.

In one embodiment a reduced diameter groove/area can be machined on the surface of one or more of the stroking joints of mandrel. In one embodiment the reduced diameter groove/area is provided in the pin by pin stroking joint of mandrel.

In one embodiment the reduced diameter groove/area can be used to lift or lower together the tool with bottleneck elevators.

In one embodiment an annular seal between joints of mandrel can be activated by rotating one mandrel joint relative to a second mandrel joint.

In one embodiment is provided plurality of joints of mandrel where the box or female end has a tapered end shoulder which cooperates with a tapered shoulder of a mating pin/male end joint to prevent the end of the female/box portion from flaring or expanding when tightened. In one embodiment shoulder of pin end and shoulder of box end are tapered. In one embodiment the tapers are substantially parallel to each other and tend to cause the box end to be squeezed/directed towards the internal axial passageway of the mandrel.

Ratio Between Wall Thickness of Pin by Pin to Box by Box End Joints

In one embodiment the ratio between wall thicknesses of mating joints of mandrel are least 2:1, 3:1, 4:1, 5:1, 6:1, 7:1, 8:1, 9:1, 10:1, 12:1, 14:1, 16:1, 18:1, and 20:1. In various embodiments the ratio can be between any two of the specified ratios. In one embodiment, the wall thicknesses of the box/female by box/female end joints are designed to be shearable in the ram blow out preventers.

In one embodiment the different wall thicknesses can be seen in Pin/male by Pin/male joints of mandrel compared to Box/female by Box/female joints of mandrel.

In this embodiment the wall box by box end joints' wall thicknesses are designed to be shearable in the ram blow out preventers.

Mandrel Comprised Of Double Pin End Joints and Double Box End Joints

In one embodiment the mandrel can be comprised of a plurality of double box/female by box/female end joints connected by double pin/male by pin/male end joints, wherein the double pin end joints are spaced apart at least 4, 5, 6, 7, 8, 9, 10, 12, 14, 16, 18, 20, 25, 30, 35, 40, 45, 50, 55, 60, 65, 70, 75, 80, 84, 85, 90, 95, and 100 feet. In various embodiments the double pin end joints can be spaced between any two of the above specified lengths.

In various embodiments the double pin end joints, in length, can be less than 48 inches, 46, 45, 44, 42, 40, 38, 36, 34, 32, 30, 28, 26, and 24 inches. In various embodiments the length of the double pin end joints can be between any two of the above specified lengths.

Sleeve With Two Spaced Apart Seal Units Dealing With Recessed Areas of Mandrel

In one embodiment, within the stroking length of the exterior sealing area of the mandrel with respect to the sleeve/housing includes at least one recessed area in the external sealing surface of the mandrel (which recessed area is used for supporting the weight of the drill string and swivel tool during the process of tripping in the swivel tool into the well bore). In one embodiment the mandrel includes a plurality of recessed areas spaced apart the longitudinal length of the mandrel and within the stroking length of the sleeve/housing.

In various embodiments such recessed area or areas can cause a seal unit in the sleeve/housing to lose partial or complete sealing between sleeve and mandrel when such seal unit passes over the recessed area. In various embodiments, such a partial or complete loss of sealing of one seal unit is compensated by the remaining seal of the other spaced apart sealing unit (which maintains a seal between sleeve and mandrel on the external sealing surface of the mandrel).

In various embodiments, one or more recessed areas in the external sealing portion of the mandrel includes at least one transition piece which is of a softer material than the material comprising the external sealing area of the mandrel, for example teflon compared to steel. Other examples include rubber, viton, plastic, polymer,

In one embodiment, the mandrel can be stroked/reciprocated with respect to the sleeve/housing causing one or more recessed areas in the external sealing area of the mandrel to pass through the sleeve. In one embodiment, with the sleeve having first and second spaced apart sealing, the mandrel is moved relative to the sleeve wherein:

(1) first and second seal units maintain independent sealing between sleeve and mandrel;

(2) first seal unit moves across recessed area of mandrel but second seal unit maintains seal between sleeve and mandrel; or,

(3) second seal unit moves across recessed area of mandrel but first seal unit maintains seal between sleeve and mandrel.

In one embodiment, the longitudinal length of one or more recessed areas in the mandrel can be between 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 14, 16, 18, 20, 22, 24, 26, 28, 30, 32, 34, 36, 40, 45, 50 inches; and the spacing between the spaced apart seal units in the sleeve/housing.

Sealing Inserts for Thin Walled Sections

One embodiment includes inserts for the thin walled sections of box/female by box/female joints of mandrel.

One embodiment has the inserts being slidable relative to the joint of mandrel in which the insert is contained.

One embodiment has the inserts having an internal bore transition, from small to large bore internal flow passage.

One embodiment includes the insert with an annular recess for at least partially containing an internal sealing unit.

General Method of Making Up Stroking Mandrel When On Rig

In one embodiment is provided a method of determining the stroking length of a rotating and reciprocable swivel tool at a drilling rig or platform having a floor, comprising the steps of:

(a) providing a swivel tool, the swivel tool comprising a mandrel and a sleeve, the mandrel being rotatable and reciprocable relative to the sleeve/housing, the mandrel having a first stroke length relative to the sleeve/housing;

(b) supporting in a substantially vertical direction the swivel tool at the rig;

(c) adding a mandrel joint to the top of the mandrel, such additional joint increasing the stroking length of the mandrel relative to the first stoking length;

(d) lowering the swivel tool and again supporting in a vertical direction the swivel tool in a substantially vertical direction on the rig; and

(e) repeating steps “c” and “d” unit the final stroking length of the mandrel relative to the sleeve/housing is at least 100 feet.

In various embodiments the steps “c” and “d” can be repeated until the final stroking length can be greater than about 100, 150, 200, 250, 300, 350, 400, 450, 500, 550, 600, 700, 800, 900, 1000, 1200, 1400, 1500, 1600, 1800, and 2000 feet, or any stroke lengths between any two of the specified stroke lengths.

In various embodiments a plurality of the mandrel joints include recessed areas in the exterior sealing surface, and during step “c” one of these recessed areas is used to support the swivel tool in a substantially vertical direction.

In one embodiment the plurality of recessed areas can include soft material transition sections.

In various embodiments the upper portions of the recessed areas can be frustoconical.

In various embodiments the upper portions of the recessed areas can be tapered.

On embodiment comprises a method of increasing stroke length of the mandrel while located on rig or platform.

One embodiment comprises a method of making up the mandrel while on rig or platform.

General Method Steps

In one embodiment the method can comprise the following steps:

(a) lowering the rotating and reciprocating tool to the annular BOP, the tool comprising a sleeve and a mandrel;

(b) after step “a”, having the annular BOP close on the sleeve;

(c) after step “b”, causing relative longitudinal movement between the sleeve and the mandrel; and

(d) after step “c”, performing wellbore operations.

In various embodiments the method can include one or more of the following additional steps:

(1) after step “c”, moving the sleeve outside of the annular BOP;

(2) after step “(1)”, moving the sleeve inside of the annular BOP and having the annular BOP close on the sleeve;

(3) after step “(2)”, causing relative longitudinal movement between the sleeve and the mandrel.

In one embodiment, during step “a”, the sleeve is longitudinally locked relative to the mandrel.

In one embodiment, after step “b”, the sleeve is unlocked longitudinally relative to the mandrel.

In one embodiment, after step “c”, the sleeve is longitudinally locked relative to the mandrel.

In one embodiment, during step “c” operations are performed in the wellbore.

In one embodiment, during step “(3)” operations are performed in the wellbore.

In one embodiment, during step “c” the tool is fluidly connected to a string having a bore and fluid is pumped through at least part of the string’s bore.

In one embodiment, during step “(3)” the tool is fluidly connected to a string having a bore and fluid is pumped through at least part of the string’s bore.

In one embodiment, during step “c” the tool is fluidly connected to a string having a bore and fluid is pumped through at least part of the string’s bore and fracturing operations performed.

In one embodiment, during step “(3)” the tool is fluidly connected to a string having a bore and fluid is pumped through at least part of the string’s bore and fracturing operations performed.

In one embodiment, longitudinally locking the sleeve relative to the mandrel shortens an effective stroke length of the sleeve from a first stroke to a second stroke.

In one embodiment, during step “a”, the mandrel can freely rotate relative to the sleeve.

In one embodiment, after step “b”, the mandrel can freely rotate relative to the sleeve.

In one embodiment, after step “c”, the mandrel can freely rotate relative to the sleeve.

To provide the completion engineers with the flexibility:

(a) to use the rotating and reciprocating tool while the annular BOP is sealed on the sleeve and while taking return flow up the choke or kill line (i.e., around the annular BOP); or

(b) to open the annular BOP and take returns up the subsea riser (i.e., through the annular BOP); or

(c) to open the annular BOP and move the completion string with the attached rotating and reciprocating tool out of the annular BOP (such as where the completion engineer wishes to use a jetting tool to jet the BOP stack or perform other operations requiring the completion string to be raised to a point beyond where the effective stroke capacity of the rotating and reciprocating tool can absorb the upward movement by the sleeve moving longitudinally relative to the mandrel) and, at a later point in time, reseal the annular BOP on the sleeve of the rotating and reciprocating tool (bypassing the top-drive unit).

In another embodiment the method can comprise the following steps:

(a) lowering the rotating and reciprocating tool to the annular BOP, the tool comprising a sleeve and mandrel;

(b) after step “a”, having the annular BOP close on the sleeve;

(c) after step “b”, causing relative longitudinal movement between the sleeve and the mandrel; and

(d) during and/or after step “c”, performing wellbore operations.

In various embodiments the method can include one or more of the following additional steps:

(1) after step “c”, moving the sleeve outside of the annular BOP;

(2) after step “(1)”, moving the sleeve inside of the annular BOP and having the annular BOP close on the sleeve;

(3) after step “(2)”, causing relative longitudinal movement between the sleeve and the mandrel.

In one embodiment, during step “a”, the sleeve is longitudinally locked relative to the mandrel.

In one embodiment, after step “b”, the sleeve is unlocked longitudinally relative to the mandrel.

In one embodiment, after step “c”, the sleeve is longitudinally locked relative to the mandrel.

In one embodiment, during step “c” operations are performed in the wellbore.

In one embodiment, during step “(3)” operations are performed in the wellbore.

In one embodiment, during step “c” the tool is fluidly connected to a string having a bore and fluid is pumped through the choke and/or kill of the BOP to the wellbore and returned through at least part of the string’s bore up to the rig through a right angle swivel fluid diverter.

In one embodiment, during step "(3)" the tool is fluidly connected to a string having a bore and fluid is pumped through the choke and/or kill of the BOP to the wellbore and returned through at least part of the string's bore up to the rig through a right angle swivel fluid diverter.

In one embodiment, longitudinally locking the sleeve relative to the mandrel shortens an effective stroke length of the sleeve from a first stroke to a second stroke.

In one embodiment, during step "a", the mandrel can freely rotate relative to the sleeve.

In one embodiment, after step "b", the mandrel can freely rotate relative to the sleeve.

In one embodiment, after step "c", the mandrel can freely rotate relative to the sleeve.

To provide the completion engineers with the flexibility:

(a) to use the rotating and reciprocating tool while the annular BOP is sealed on the sleeve and while pumping fluid through the choke or kill line (i.e., around the annular BOP), and fluid is returned through at least part of the string's bore up to the rig through a right angle swivel fluid diverter; or

(b) to open the annular BOP and take returns up the subsea riser (i.e., through the annular BOP); or

(c) to open the annular BOP and move the completion string with the attached rotating and reciprocating tool out of the annular BOP (such as where the completion engineer wishes to use a jetting tool to jet the BOP stack or perform other operations requiring the completion string to be raised to a point beyond where the effective stroke capacity of the rotating and reciprocating tool can absorb the upward movement by the sleeve moving longitudinally relative to the mandrel) and, at a later point in time, reseal the annular BOP on the sleeve of the rotating and reciprocating tool.

The drawings constitute a part of this specification and include exemplary embodiments to the invention, which may be embodied in various forms.

BRIEF DESCRIPTION OF THE SEVERAL VIEWS OF THE DRAWINGS

For a further understanding of the nature, objects, and advantages of the present invention, reference should be had to the following detailed description, read in conjunction with the following drawings, wherein like reference numerals denote like elements and wherein:

Figure 1 is a schematic diagram showing a deep water drilling rig with riser and annular blowout preventer.

Figure 2 is another schematic diagram of a deep water drilling rig showing a rotating and reciprocating swivel detachably connected to an annular blowout preventer, along with a ram blow out preventer mounted in the christmas tree below the annular blowout preventer.

Figure 3 is a perspective view of a conventionally available annular blowout preventer.

Figure 4 is a sectional view cut through the annular and ram blow out preventers of Figure 2 with the annular seal closed on the sleeve of the rotating and reciprocating swivel.

Figure 5 is a schematic view of one embodiment of a mandrel which includes a plurality of double box end joints connected by a plurality of mandrel subs.

Figure 6 is a perspective view of one embodiment of a rotating and reciprocal swivel with sectional mandrel having joints incorporating pin end tip sealing configuration.

Figure 7 is a side view of the rotating and reciprocal swivel of Figure 6 where the sleeve is located in its lowermost position, and the center of gravity of the swivel is identified.

Figures 8A, 8B, and 8C are perspective views of the rotating and reciprocal swivel of Figure 6 where respectively the sleeve is located in its lowermost, mid stroke, and upper most positions.

Figure 9 is a side view of the sectional mandrel having joints incorporating pin end tip sealing configuration of Figure 6.

Figure 10 is a sectional view of the sectional mandrel having joints incorporating pin end tip sealing configuration of Figure 6.

Figure 11A is a sectional view of the mandrel of Figure 6 showing one of the connection joints incorporating pin end tip sealing configuration.

Figure 11B is an enlarged sectional view of the joint of Figure 11A.

Figure 12 is a sectional view of the mandrel of Figure 6 showing a joint of mandrel having two pin ends and two connecting joints incorporating pin end tip sealing configuration.

Figure 13 is an rear end view of a seal for the mandrel joints.

Figure 14 is a sectional view of the seal shown in Figure 13.

Figure 15 is an enlarged sectional view of the seal of Figure 14.

Figure 16 is a sectional view of the mandrel of Figure 6 showing the uppermost connection joint incorporating pin end tip sealing configuration.

Figure 17 is a sectional view of the mandrel of Figure 6 showing the lowermost connection joint incorporating pin end tip sealing configuration.

Figure 18 is a sectional view of the mandrel of Figure 6 showing a double female end connection joint for receiving the pin end tip sealing configuration of one embodiment.

Figure 19 is an enlarged view of a circumferential recess for receiving the pin end tip sealing configuration of one embodiment.

Figure 20 is an enlarged view of an end shoulder for limiting movement of the slidable sealing block of one embodiment.

Figure 21 is a sectional view of the mandrel of Figure 6 showing a double female end connection joint for receiving the pin end tip sealing configuration of one embodiment, but with the slidable sealing blocks omitted.

Figure 22 is an end view of the double female end connection joint of Figure 21.

Figure 23 is a sectional side view of a slidable sealing block.

Figure 24 is an end view of the slidable sealing block of Figure 23.

Figure 25 is a sectional view of a joint of mandrel having two pin ends and two connecting joints incorporating pin end tip sealing configuration

Figure 26 is an enlarged view of one of the pin ends of the mandrel joint of Figure 25.

Figure 27 is a sectional view of the uppermost mandrel joint of the mandrel shown in Figure 6, with the joint having a pin end sealing configuration of one embodiment.

Figure 28 is an enlarged view of one of the pin ends of the mandrel joint of Figure 27.

Figure 29 is a sectional view of the lowermost mandrel joint of the mandrel shown in Figure 6, with the joint having a pin end sealing configuration of one embodiment.

Figure 30 is a left end view of the mandrel joint of Figure.

Figure 31 is a right end view of the mandrel joint of Figure 29.

Figure 32 is an enlarged view of the area showing a pressure relief area between the interstitial space of the interior of the sleeve and the exterior of the mandrel.

Figure 33 is a sectional view of the lowermost mandrel joint of the mandrel shown in Figure 6, with the joint having a pin end sealing configuration of one embodiment.

Figure 34 is an enlarged view of one of the pin ends of the mandrel joint of Figure 33, having the seal of one embodiment.

Figures 35 through 37 show the operation of mating tapered shoulders and ends for the box and pin joints of the mandrel.

Figure 38 shows a pin/male by pin/male mandrel joint with recess in its exterior sealing surface being connecting to two female tubulars.

Figures 39 through 42 show various embodiments of the pin/male by pin/male mandrel joint with recess in its exterior sealing surface.

Figure 43 is a side view of a sleeve of the mandrel shown in Figure 6.

Figure 44 is a sectional view of the sleeve shown in Figure 43, with the sealing element for the pin end removed.

Figure 45 is an enlarged sectional view of an end for the sleeve shown in Figures 43 and 44.

Figures 46 through 51 schematically show stroking and sealing of mandrel relative to sleeve where mandrel has at least one recessed area in mandrel's external sealing surface.

Figure 52A is a schematic view of the upper catch portion of sleeve where the upper seal is sealing on external sealing surface of mandrel.

Figure 52B is a schematic view of the upper catch portion of sleeve where the upper seal is not sealing on external sealing surface of mandrel.

Figure 53A is a section view of the lower catch portion of sleeve where the lower seal is sealing on external sealing surface of mandrel.

Figure 53B is a section view of the lower catch portion of sleeve where the lower seal is not sealing on external sealing surface of mandrel.

Figures 54 through 62 schematically show steps of increasing the stroking length of the mandrel when on a rig.

DETAILED DESCRIPTION

Detailed descriptions of one or more preferred embodiments are provided herein. It is to be understood, however, that the present invention may be embodied in various forms. Therefore, specific details disclosed herein are not to be interpreted as limiting, but rather as a basis for the claims and as a representative basis for teaching one skilled in the art to employ the present invention in any appropriate system, structure or manner.

During drilling, displacement, and/or completion operations it may be desirable to perform down hole operations when the annular seal of an annular blow out preventer is closed on the drill string and rotation and/or reciprocation of the drill string is desired. One such operation can be a frac (or fracturing) operation where pressure below the annular seal 71 is increased in an attempt to fracture the down hole formation.

Figures 1 and 2 show generally the preferred embodiment of the apparatus of the present invention, designated generally by the numeral 10. Drilling apparatus 10 employs a drilling platform S that can be a floating platform, spar, semi-submersible, or other platform suitable for oil and gas well drilling in a deep water environment. For example, the well drilling apparatus 10 of Figures 1 and 2 and related method can be employed in deep water of for example deeper than 5,000 feet (1,500 meters), 6,000 feet (1,800 meters), 7,000 feet (2,100 meters), 10,000 feet (3,000 meters) deep, or deeper.

In Figures 1 and 2, an ocean floor or seabed 87 is shown. Wellhead 88 is shown on seabed 87. One or more blowout preventers can be provided including stack 75 and annular blowout preventer 70. The oil and gas well drilling platform S thus can provide a floating structure S having a rig floor F that carries a derrick and other known equipment that is used for drilling oil and gas wells. Floating structure S provides a source of drilling fluid or drilling mud 22 contained in mud pit MP. Equipment that can be used to recirculate and treat the drilling mud can include for example a mud pit MP, shale shaker SS, mud buster or separator MB, and choke manifold CM.

An example of a drilling rig and various drilling components is shown in Figure 1 of United States of America patent number 6,263,982 (which patent is incorporated herein by reference). In Figures 1 and 2 conventional slip or telescopic joint SJ, comprising an outer barrel OB and an inner barrel IB with a pressure seal therebetween can be used to compensate for the relative vertical movement or heave between the floating rig S and the fixed subsea riser R. A Diverter D can be connected between the top inner barrel IB of the slip joint SJ and the floating structure or rig S to control gas accumulations in the riser R or low pressure formation gas from venting to the rig floor F. A ball joint BJ between the diverter D and the riser R can compensate for other relative movement (horizontal and rotational) or pitch and roll of the floating structure S and the riser R (which is typically fixed).

The diverter D can use a diverter line DL to communicate drilling fluid or mud from the riser R to a choke manifold CM, shale shaker SS or other drilling fluid or drilling mud receiving device. Above the diverter D can be the flowline RF which can be configured to communicate with a mud pit MP. A conventional flexible choke line CL can be configured to communicate with choke manifold CM. The drilling fluid or mud can flow from the choke manifold CM to a mud-gas buster or separator MB and a flare line (not shown). The drilling fluid or mud can then be discharged to a shale shaker SS, and mud pits MP. In addition to a choke line CL and kill line KL, a booster line BL can be used.

Figure 2 is an enlarged view of the drill string or work string 85 that extends between rig 10 and seabed 87 having wellhead 88. In Figure 2, the drill string or work string 85 is divided into an upper drill or work string and a lower drill or work string. Upper string is contained in riser 80 and extends between well drilling rig S and swivel 100. An upper volumetric section 90 is provided within riser 80 and in between drilling rig 10 and swivel 100. A lower volumetric section 92 is provided in between wellhead 88 and swivel 100. The upper and lower volumetric sections 90, 92 are more specifically separated by annular seal unit 71 that forms a seal against sleeve 300 of swivel 100. Annular blowout preventer 70 is positioned at the bottom of riser 80 and above stack 75. A well bore 40 extends downwardly from wellhead 88 and into seabed 87. Although shown in Figure 2, in many of the figures the lower completion or drill string 85 has been omitted for purposes of clarity.

Figures 1 and 2 are schematic views showing oil and gas well drilling rig 10 connected to riser 80 and having annular blowout preventer 70 (commercially available). Figure 2 is a schematic view showing rig 10 with swivel 100 separating. Swivel 100 is shown detachably connected to annular blowout preventer 70 through annular packing unit seal 71.

Figure 4 includes a schematic diagram of one embodiment of a swivel tool 100 which can rotate and/or stroke/reciprocate. With such construction drill or well string 85 can be rotated and/or stroked/reciprocated while annular blowout preventer 70 is sealed around sleeve or housing 300 of swivel tool 100. Figure 3 is a drawing of the exterior of annular blow out preventer 70.

Mandrel 110 is contained within a bore of sleeve 300. Swivel 100 includes an outer sleeve or housing 300 having a generally vertically oriented open-ended bore that is occupied by mandrel 110. Sleeve 300 provides upper catch, shoulder or flange 326 and lower catch, shoulder or flange 328.

Figure 6 is a perspective view of one embodiment of a swivel tool 100 having a rotating and reciprocal sleeve 300 with sectional mandrel 110 having joints incorporating pin end tip sealing configuration. Generally, the stroke length (relative longitudinal movement between mandrel 110 and sleeve 300) is equal to the length of the mandrel 110 (Lm) minus the length of the sleeve (Ls).

Figure 7 is a side view of the rotating and reciprocal swivel 100 where the sleeve 300 is located in its lowermost (and latched) position, and the center of gravity of the swivel 100 is identified. In this embodiment no sealing area recesses (e.g., 706, 906, etc. are shown). Figures 8A, 8B, and 8C are perspective views of the rotating and reciprocal swivel tool 100 where respectively the sleeve 300 is located in its lowermost (Figure 8A), mid stroke (Figure 8B), and upper most (Figure 8C) positions.

Without external sealing areas recesses, the overall length of mandrel 110 may be limited to the height of the derrick of the rig because the mandrel 110 will preferably be made up at the shop, as making it up in the field will likely scratch/damage the sealing areas of mandrel 110.

Figure 9 is a side view of made up mandrel 110 having joints incorporating pin end tip sealing configuration of Figure 6. Figure 10 is a sectional view of mandrel 110 having joints incorporating an inner diameter sealing as will be described below. Mandrel 110 can be comprised of joints 500, 600, 700, 800, 900, 1000, and 1100. Depending on the desired stroke length of mandrel 110, additional joints of mandrel can be used.

Figure 12 is a sectional view of mandrel 110 showing a joints 600,700,800 of mandrel 110 having two pin ends (joint 700) and two connecting joints (600,800) incorporating box/male by box/male connections, and including sealing insert 1500 having an annular recess 1540 for seal 750. Figure 11A is a sectional view of a joint of mandrel 110 which incorporates the inner diameter sealing configuration using seal 750 which is contained in mating annular recesses 728 (of joint 700) and 1540 (of joint 600). Figure 11B is an enlarged sectional view of the joint of Figure 11A.

Figure 13 is an end view of a seal 750 or 760 which can be used mating annular recesses 728 (of mandrel joint 700) and 1540 (of mandrel joint 600). Figure 14 is a sectional view of the seal 750. Figure 15 is an enlarged sectional view of the seal 750. First seal 750 can comprise first end 752, widened area of first seal 753, second end of first seal 755, tapered area of first seal 756, and vertical area of first seal 757. Tapered areas 756,756' can be used to assist second end 755 of seal 750 to enter recess 1540 of insert 1500 when joint 700 is being threaded into joint 600. Seal 750 can have inner sealing diameter 770 and outer sealing diameter 774 (which are defined by vertical walls 757).

Figure 16 is a sectional view of mandrel 110 showing the uppermost connection joint (joint 600 threaded onto joint 500) incorporating pin end tip sealing configuration. Seal 550 can be of similar construction to seal 750 shown in Figure 13. Shoulder 570 can limit stroke length of mandrel 110 relative to sleeve 300 when catch 326 contacts shoulder 570.

Figure 17 is a sectional view of mandrel 110 showing the lowermost connection joint (joint 1000 threaded onto joint 1100) incorporating pin end tip sealing configuration. Seal 1150 can be of similar construction to seal 750 shown in Figure 13. Shoulder 570 can limit stroke length of mandrel 110 relative to sleeve 300 when locking shoulder 1200 limits further movement of catch 328.

Figure 18 is a sectional view of one box/female by box/female type joint 600 of mandrel 100 showing a double female end connection joint for receiving the pin end tip sealing configuration of one embodiment. Figure 19 is an enlarged view of a circumferential recess 1540' for receiving the seal (e.g., seal 750 shown in Figures 11 and 12). Figure 20 is an enlarged view (Detail A) of an end shoulder 660 for limiting movement of the slidable sealing block 1500 of one embodiment.

Figure 21 is a sectional view joint 600, but with the slidable sealing blocks 1500,1500' omitted. Figure 22 is an end view of the double female end connection joint 600.

Figure 23 is a sectional side view of a slidable sealing block 1500. Figure 24 is an end view of the slidable sealing block 1500. On first end 1520, sealing block 1500 can include annular recess 1540, which itself can include tapered walls 1546, and vertical section 1544. Tapered walls 1546 can be constructed to match/cooperate with the tapered areas of the seal (such as tapered area 756 of seal 750). Annular recess 1540 can have nominal diameter 1550, with outer diameter 1552 and inner diameter 1554 created by vertical walls 1544. Insert 1500 can include an axial passage 1510 having at least one transitional portion 1534 to transition from the larger diameter axial passages of the box/female by box/female joints (e.g., 600, 800, 1000 etc.) to the smaller diameter axial passes of the pin/male by pin/male joints (e.g., 700, 900, etc.).

Figure 25 is a sectional view of a joint 700 of mandrel 110 having two male/pin ends 720,730 and two connecting joints incorporating pin end tip sealing configuration (annular recesses 728 and 738 respectively holding first seal 750 and second seal 760). Figure 26 is an enlarged view of the threads 722 of one end 720 of double male end mandrel joint 700.

Figure 26 is an enlarged view of one of the pin ends 720 of the mandrel joint 700 with attached seal 750 inserted into the annular recess 728. Seal 750 can be as described before and attached to annular recess 728. Joint 700 can include axial passage 710 (with diameter 712) and first threads 722 (on upper end connection 720) with second threads 732 (on lower end connection 730). Annular recess 728 can include enlarged area 729 which cooperates and holds enlarged area 753 of seal 750. Annular recess 738 can be constructed similarly with enlarged area 739.

It is noted that, when joint 700 is threaded into joints 600 and 800, seals 750 and 760 of joint 700 will both remain exterior to the projected cross section of axial passage 710 with diameter 712, but interior to the projected cross section of axial passage 610 with diameter 612 and axial passage 810 with diameter 812.

Figure 27 is a sectional view of the uppermost mandrel joint 500 of mandrel 110, with joint 500 having a pin/male end 530 incorporating seal 550 (which can be of the same configuration as seal 750 described above). Joint 500 can include shoulder 533 for limiting longitudinal movement between sleeve 300 and mandrel 110. Figure 28 is an enlarged view of one of the pin end 530. Annular recess 538 can include enlarged area 539 for holding in place seal 550. Second end 520 can include a box/female connection which can attach to additional non-mandrel string joints.

Figure 29 is a sectional view of the lowermost mandrel joint 1100 of mandrel 110, with the joint having a pin end (at end 1120) sealing configuration (seal 1150 which can be of the same construction as seal 750 described above). Figure 30 is left end view of joint 1100. Figure 31 is a right end view of joint 1100. Figure 32 is an enlarged view of the area showing a pressure relief area 1400, for relaxing/relieving pressure between the interstitial space of the interior of the sleeve 300 and the exterior of the mandrel 110 (when sleeve 300 is in its lowermost and quick locked condition). Figure 33 is a sectional view of the lowermost mandrel joint 1100. Seal 1150 on end 1120 and placed in recess 1128 (being held by enlarged area 1129 cooperating with enlarged area 1153 of seal 1150) can be used to seal between joint 1100 and the connecting box/female by box/female joint 1000. Figure 34 is an enlarged view of one of ends 1120 of joint 1100.

Mandrel Joints Include Mating Tapers To Prevent Flaring Of Box End Connection

Figures 35 through 37 show three sequence steps making a connection between a box/female end (end 630 of mandrel joint 600 being made up to end 720 of mandrel joint 700).

For purposes of clarity insert 1500 and seal 750 have been omitted from these drawings. Arrow 670 schematically indicates that joints 600 and 700 are threadably connected to each other by rotation. As tapered shoulder 721 comes close to tapered end 621 of end 630 of joint 600, the mating tapers 721,621 will tend to cause the edges of joint 600 to be compressed toward axial passageway 610, and not allow the ends of joint 600 to flare out away from axial passageway 610 when joints 600,700 are made up at higher torques.

Resistance to flaring of the box end connections keeps the exterior sealing surface 601 of joint 600 flush with exterior sealing surface 701 of joint 700. Such flushness/smoothness/levelness between mating exterior sealing surfaces (701 and 601, and by analogy the exterior sealing surfaces of other adjoining mandrel 110 joints), facilitates proper sealing between sleeve 300 and mandrel 110, along with increasing seal life of seal units 370,380 of sleeve 300.

In different embodiments the mating shoulders can have a tapered portion with a taper at about 1, 2, 3, 4, 5, 6, 6.25, 7, 8, 9, 10, 12, 13, 14, 15, and 20 degrees from a line perpendicular to the longitudinal centerline of a joint. In various embodiments the tapers can be within a range of between about any two of the specified degrees. Mating tapers can have equal magnitude but opposite tapers or slopes.

Figures 38 through 42 show various embodiments of the pin/male by pin/male mandrel joint with recess in its exterior sealing surface.

Figure 38 shows joints 600, 700, and 800 attached with exterior sealing surfaces 601, 701, and 801. Joint 700 includes recess 706 in its exterior sealing surface 701. Recess 706 can include upper transition area 740 and lower transition area 746. Transition areas can include softer transition inserts 742 and 748 as described below. Although inserts 1500, 1500', 1500", and 1500"' are shown interior seals 750 and 760 have been omitted for clarity (but are intended to be used as shown in other embodiments for with interior sealing).

Additionally, a single piece pin by pin mandrel joint 700 is shown in Figures 38 to 55, however, it is contemplated that the pin by pin sub can be two pieces (such as shown in Figures 54 through 62 where mandrel joint 700 is comprised of joint 700' having the recess 706 and being a box by pin join in combination with joint 700" being a pin by pin joint the combination being a pin by pin joint with recess 706).

Figures 39 through 42 show pin by pin mandrel joint 700 with recess 706. Recess 706 can include upper transition area 740 and lower transition area 746. Transition areas can include softer transition inserts 742 and 748. Joint 700 can include tapered shoulders 723 and 733 as described in other embodiments.

Figure 43 is a side view of a sleeve 300. Figure 44 is a sectional view of sleeve 300, with the sealing elements removed from its ends. Figure 45 is an enlarged sectional view (Detail A) of an end of sleeve 300.

Mandrel Is Shearable For Ram Blow Out Preventer Regardless of Vertical Position of Mandrel

The wall thickness 604, 804, 1004, etc. of box end joints 600, 800, 1000, etc. will be such that the walls can be sheared by one of the rams 2010, 2020, 2030, and/or 2040 of plurality of stacked ram blow out preventers 2000.

The preferred wall thickness for 604, 804, 1004, etc. can be selected from the set of thicknesses in inches less than about 1, 15/16, 7/8, 13/16, 3/4, 11/16, 10/16, 9/16, 8/16, 7/16, 6/16, 5/16, 4/16, 3/16, and 1/4. In various embodiments the wall thickness can be between any two of the specified thicknesses.

In one embodiment the spacing between double pin subs 700, 900, etc. is such that at any one point in time only one of such subs 700, 900, and/or another double pin sub can be aligned with a ram of a plurality of stacked ram blow out preventers.

Figure 4 is a sectional view cut through the annular 70 and ram 2040 blow out preventers with the annular seal 71 closed on the sleeve 300 of the rotating and reciprocating swivel 100. Mandrel 110 which comprises mandrel joints 600, 800, 1000 connected together by double pin subs 700, 900 are also schematically shown in Figure 4.

Schematically shown in Figure 4 is the spacing L_2 between subs 700 and 800 is such that at any one point in time only one of subs 700 or 900 can be aligned with a ram of a ram blow out preventer 2000. Plurality of stacked ram blow out preventers 2000 can include rams 2010, 2020, 2030, and 2040. Distance 2050 is between rams 2010 and 2020. Distance 2052 is between rams 2010 and 2030. Distance 2054 is between rams 2030 and 2040. Distance 2056 is between rams 2020 and 2040. Distance 2058 is between rams 2020 and 2030.

In this embodiment none of the distances 2050, 2052, 2054, 2056, and/or 2058 can fall within the range of:

L_1 +/- (L_4 + L_6) (as shown in Figures 4 and 5).

In this manner there is no possibility that more than one ram (2010, 2020, 2030, and/or 2040) can land on a double pin sub 700, 900, etc., regardless of the amount of longitudinal stroking reciprocation of mandrel 110 relative to sleeve 300, or the longitudinal position of mandrel 110 relative to ram blow out preventer 2000 (assuming that sleeve 300 is not positioned in ram blow out preventer 2000).

In one embodiment the length of any double box end joint 600, 800, 1000 etc. is greater than at least about 4 feet. In other embodiments the length is at least greater than about 5, 6, 7, 8, 9, 10, 12, 14, 15, 16, 18, 20, 25, 30, 35, and 40 feet. In other embodiments the length is between any two of the above specified lengths.

The wall thickness 604, 804, 1004, etc. of double box end joints 600, 800, 100, etc. will be such that the walls can be sheared by one of the rams 2010, 2020, 2030, and/or 2040 of ram blow out preventer 2000.

Swivel 100 can be comprised of mandrel 110 and sleeve or housing 300. Sleeve or housing 300 can be rotatably, strokably/reciprocably, and/or sealably connected to mandrel 110. Accordingly, when mandrel 110 is rotated and/or reciprocated sleeve or housing 300 can remain stationary to an observer insofar as rotation and/or reciprocation is concerned. Sleeve or housing 300 can fit over mandrel 110 and can be rotatably, reciprocably, and sealably connected to mandrel 110.

Sleeve or housing 300 can be rotatably connected to mandrel 110 by one or more bushings and/or bearings, preferably located on opposed longitudinal ends of sleeve or housing 300.

Sleeve or housing 300 can be sealingly connected to mandrel 110 by a one or more seals (e.g., packing units 370 and 380), preferably spaced apart and located on opposed longitudinal ends of sleeve or housing 300. The seals can seal the gap 315 between the interior 310 of sleeve or housing 300 and the exterior of mandrel 110.

Sleeve or housing 300 can be reciprocally connected to mandrel 110 through the geometry of mandrel 110 which can allow sleeve or housing 300 to slide relative to mandrel 110 in a longitudinal direction (such as by having a longitudinally extending distance H_T of the exterior surface of mandrel 110 a substantially constant diameter).

Swivel 100 can be made up of mandrel 110 to fit in line of a drill or work string 85 and sleeve or housing 300 with a seal and bearing system to allow for the drill or work string 85 to be rotated and reciprocated at swivel 100 where annular seal unit 71 is closed on sleeve 300. This can be achieved by locating swivel 100 in the annular blow out preventer 70 where annular seal unit 71 can close around sleeve or housing 300 forming a seal between sleeve or housing 300 and annular seal unit 71.

The amount of reciprocation (or stroke) can be controlled by the difference between the height H_T of mandrel 110 and the length Ls of the sleeve or housing 300. As shown in Figure 6, the stroke of swivel 100 can be the difference between height H_T of mandrel 110 and length 350 of sleeve or housing 300.

Figures 7 and 8 show a sectional view through the sleeve 300 and mandrel 110. In one embodiment sealing units 370 and 380 can be two way seals. One advantage of using two sets of sealing units 370 and 380 which each seal in opposite longitudinal directions is that the sleeve 300 and mandrel 110, even where one or more of the double pin subs (e.g., 700, 900, etc.) with its recessed portion (e.g., 706, 906, etc.) is passing through the sealing unit, the spaced apart sealing unit can still seal against fluid flow. This backup sealing ability assists in maintaining sealing during vertical movement of mandrel 110 relative to sleeve 300.

Maintaining Sealing Between Mandrel and Sleeve During Rotation and/or Stroking/Reciprocation Where Mandrel Includes One Or More Recessed Areas In Its Exterior Sealing Surface

Figures 46 through 51 schematically illustrating stroking/reciprocating motion of sleeve or housing 300 relative to mandrel 110. In this embodiment mandrel 110 can have one or more recessed areas (e.g., 706, 906, etc.) in its exterior sealing surfaces (e.g., 601, 701, 801, 901, 1001, etc.) but still maintain a seal between sleeve/housing 300 and mandrel 110.

Sealing is maintained notwithstanding sleeve 300 (and one of the sealing units) passing over one of the recessed areas in the external sealing surface of mandrel 110 by the remaining spaced apart sealing unit still maintaining a seal between sleeve 300 and mandrel 110. In this embodiment sleeve 300 includes spaced apart sealing units 370,380 located respectively under catches 326,328.

In these figures arrows 3000,3001,3002,3003, 3004, and 3005 schematically indicate downward movement of mandrel 110 relative to sleeve 300. Additionally, arrows 3010,3011,3012,3013, 3014, and 3015 schematically indicate upward movement of mandrel 110 relative to sleeve 300.

The height L_m of mandrel 110 compared to the overall length L_s 350 of sleeve or housing 300 can be configured to allow sleeve or housing 300 to stroke/reciprocate (e.g., slide up and down) relative to mandrel 110. Figures 46 through 51 are schematic diagrams illustrating stroking/reciprocation and/or rotation between sleeve or housing 300 along mandrel 110 (allowing reciprocation and/or rotation between drill or work string 85 when annular seal 71 of annular blow out preventer 70 is closed and sealed on sleeve 300, and drill or work string 85, thereby sealing the bore hole from above – with the sleeve being closed in annular blow out preventer being shown in Figure 2).

In Figures 46 through 51 (in such order) with arrows 3000, 3001, 3002, 3003, 3004 and 3005 schematically indicate a downward stroke of mandrel 110 relative to sleeve 300 in the direction of arrow 3000. In Figures 46 through 51 (in reverse order of Figure 51 down to Figure 46) with arrows 3010, 3011, 3012, 3013, 3014, and 3015 schematically indicate an upward stroke of mandrel 110 relative to sleeve 300. During stroking of mandrel 110 relative to sleeve 300, packing units 370 and 380 maintain a seal between sleeve 300 and mandrel 110, while annular seal 71 maintains a seal on sleeve 300 thereby sealing wellbore 40.

In Figures 46 and 47, arrows 3000,3001 schematically indicate that mandrel 110 is moving downward relative to sleeve or housing 300, where a double pin end sub 900 is located above the level of upper catch 326 (and upper packing unit 370) of sleeve 300. While upper packing unit 370 may not maintain a seal when double pin end sub 900 passes through (e.g., recessed area 906 causing a break in the sealing between packing unit 370 and sub 900 as shown in Figure 52B), lower packing unit 380 (in lower catch 328) maintains a seal between sleeve 300 and mandrel 110 (as shown in Figure 53A), while annular seal 71 of annular blow out preventer 70 maintains a seal on sleeve 300 thereby sealing wellbore 40.

In Figure 48, arrow 3002 schematically indicates that mandrel 110 continues to stroke downwardly relative to sleeve or housing 300, where a double pin end sub 900 (and recess 906) is located between upper catch 321 (and upper packing unit 370) and lower catch 328 (and lower packing unit 380). Now both packing units 370 and 380 maintain a seal between sleeve 300 and mandrel 110 (as shown in Figures 52A and 53A), while annular seal 71 maintains a seal on sleeve 300 thereby sealing wellbore 40.

In Figure 49, arrow 3003 schematically indicates that mandrel 110 continues to stroke downwardly relative to sleeve or housing 300, where now a double pin end sub 900 is located at the level of lower catch 328 (and lower packing 380 unit) of sleeve 300. While packing unit 380 may not maintain a seal when recess 906 of double pin end sub 900 passes through (e.g., recessed area 906 causing a break in the sealing as shown in Figure 53B), upper packing unit 370 maintains a seal between sleeve 300 and mandrel 110 (as shown in Figure 52A), while annular seal 71 maintains a seal on sleeve 300 thereby sealing wellbore 40.

Figures 50 and 51 schematically indicate continued downwardly stroking of mandrel 110 through sleeve or housing 300 wherein the next recessed joint (double pin sub 700 with recessed area 706) will pass through sleeve 300. The spaced apart sealing units 370 and 380 of sleeve will either jointly or singularly maintain a seal between sleeve 300 and mandrel 110 when one of these sealing units passes over the recessed area (similar to that described with Figures 46 through 49 regarding joint 900 and recess 906). In Figure 50 both packing units 370 and 380 maintain a seal between sleeve 300 and mandrel 110 (as shown in Figures 52A and 53A), while annular seal 71 maintains a seal on sleeve 300 thereby sealing wellbore 40. In Figure 51, while packing unit 370 may not maintain a seal when double pin end sub 700 passes through (e.g., recessed area 706 causing a break in the sealing as shown in Figure 52B), packing unit 380 maintains a seal between sleeve 300 and mandrel 110 (as shown in Figure 53A), while annular seal 71 maintains a seal on sleeve 300 thereby sealing wellbore 40.

On the other hand, an upward stroking movement of mandrel 110 through sleeve 300 is schematically indicated by arrows 3015,3014,3013,3012,3011, and 3010 in the reverse order of Figures 51 through 46.

In the above described manner a seal can be maintained between mandrel 110 and sleeve 300 notwithstanding various recesses in the sealing area of mandrel 110 that sleeve 300 sees during relative stroking/reciprocation movement of mandrel 110 relative to sleeve 300.

Adjusting Stroking Length Of Mandrel - - Double Box End Mandrel Can Be of Different Heights Which Can Be Made Up On the Rig

Figure 5 shows is a swivel tool 100 with mandrel 110 and sleeve 300. Figure 5 is a schematic view of one embodiment of a mandrel 110 which includes a plurality of double box end joints (600, 800, 1000) connected by a plurality of double pin end subs (700, 900).

The overall stroking height H_T of double box mandrel 110 can be equal to the sum of the lengths of the joints and subs making it up. In this case the overall height H_T of mandrel 110 is equal to $L_1 + L_2 + L_3 + L_4 + L_6$. To change the overall height H_T (to be either more or less) different numbers of mandrel joints 600, 800, 1000 can be used to make up mandrel 110. Another way to change the overall height H_T of mandrel 110 is to use mandrel joints 600, 800, 1000 of different lengths.

Double box end joint 600 can be of a length L_1, and can include longitudinal passage with a box connection at its upper end 620 along with box connection at its lower end 630.

Double box end joint 800 can be of a length L_2, and can include longitudinal passage with a box connection at its upper end 820 along with box connection 850 at its lower end 830.

Double box end joint 1000 can be of a length L_3, and can include longitudinal passage 1010 (not shown) with a box connection at its upper end 1020 along with box connection at its lower end 1030.

Double pin sub 700 can comprise upper end 720, lower end 730 along with longitudinal passage 710. Sub 700 can also include upper shoulder 723, lower shoulder 733, and recessed area 706.

Recessed area 706 can be used for supporting mandrel 110 after joints 600, 800, 1000, etc. have been connected to each other forming mandrel 110. Supporting mandrel 110 using one of the recessed areas of the mandrel without gripping the sealing surfaces of joints 600,800,1000, etc. for supports prevents such surfaces from being scratched and/or damaged thus causing problems or failure of a seal between mandrel 110 and sleeve 300 (i.e., sealing with seal units 370 and/or 380). Additionally, supporting mandrel 110 using one of the recessed areas in the double pin subs, where such subs are damaged, allows replacement of the subs 700, 900, etc., while protecting (and preventing the requirement to replace) the more expensive double box end mandrel joint pieces 600, 800, 1000, etc.

Box connection of lower end 630 for joint 600 can be threadably connected to upper end 710 of double pin sub 700. Box connection of the upper end 820 of mandrel joint 800 can be threadably connected to lower end 730 of double pin sub 700.

Figure 5 is a close up sectional and schematic view of the connections between three double box end joints 600, 800, 1000 and two double pin end subs 700, 900. Here mandrel joints 600, 800, and 1000 are being connected using double pin end subs 700 and 900.

Double pin sub 900 can comprise upper end 920, lower end 930 along with longitudinal passage 910. Sub 900 can also include upper shoulder 923, lower shoulder 933, and recessed area 906.

Box connection as the lower end 630 of joint 600 can be threadably connected to upper end 720 of double pin sub 700. Box connection at the upper end 820 of mandrel joint 800 can be threadably connected to lower end 730 of double pin sub 700.

Box connection at the lower end 830 of joint 800 can be threadably connected to upper end 910 of double pin sub 900. Box connection at the upper end 1020 of mandrel joint 1000 can be threadably connected to lower end 930 of double pin sub 900.

Now, recessed areas 706, or 906 can be used for supporting made up mandrel 110 after joints 600, 800, 1000, etc. have been connected to each other forming mandrel 110. Supporting mandrel 110 in the recessed areas 706,906 (i.e., non-sealing areas) without grabbing onto the sealing surfaces of joints 600,800,1000, etc. prevents such surfaces from being scratched and/or damaged thus causing problems or failure of a seal between mandrel 110 and sleeve 300 (i.e., sealing with seal units 370 and/or 380).

In one embodiment, mandrel 110 of swivel tool 100 can be at least partially lengthened while being tripped downhole.

Figures 54 through 62 show various steps of adjusting the stroking length of mandrel 110 while at the rig. These are schematic figures where in all cases the stroking length of mandrel 110 is contemplated as being substantially straight in the longitudinal direction although the schematic drawings may have copying errors which appear to indicate a partially bent mandrel 110.

In one embodiment is provided a method of determining the stroking length of a rotating and reciprocable swivel tool 100 at a drilling rig or platform having a floor, comprising the steps of:

(a) providing a swivel tool 100, the swivel tool 100 comprising a mandrel 110 and a sleeve 300, the mandrel 110 being rotatable and reciprocable relative to the sleeve/housing 300, the mandrel 110 having a first stroke length relative to the sleeve/housing (shown in Figure 54);

(b) supporting in a substantially vertical direction the swivel tool 100 at the rig 10 (shown in Figure 54 where tool 100 is supported by rig elevators on rig floor using recessed area 906);

(c) adding a mandrel joint to the top of the mandrel 110, such additional joint increasing the stroking length of the mandrel 110 relative to the first stoking length (shown in Figure 55 where the mandrel joint is selected from a plurality of mandrel joints such as those shown in Figure 56 - - the made up mandrel 110' is shown in Figure 57);

(d) lowering the swivel tool and again supporting in a vertical direction the swivel tool in a substantially vertical direction on the rig (schematically shown between Figures 54 and 57 with the down arrow and, in Figure 57 mandrel 110' is supported by elevator using recess 706); and

(e) repeating steps "c" and "d" until the final stroking length of the mandrel 110 relative to the sleeve/housing is at least 100 feet.

In various embodiments the steps "c" and "d" can be repeated until the final stroking length can be greater than about 100, 150, 200, 250, 300, 350, 400, 450, 500, 550, 600, 700, 800, 900, 1000, 1200, 1400, 1500, 1600, 1800, and 2000 feet, or any stroke lengths between any two of the specified stroke lengths.

In various embodiments a plurality of the mandrel joints include a recessed areas (e.g., 706, 906, etc.) in the exterior sealing surface, and during step "c" the one of these recessed areas are used to support the swivel tool in a substantially vertical direction.

In one embodiment the plurality of recessed areas can include soft material transition sections.

In various embodiments the upper portions of the recessed areas can be frustoconical.

In various embodiments the upper portions of the recessed areas can be tapered.

One embodiment comprises a method of increasing stroke length of mandrel while located on rig or platform.

One embodiment comprises a method of making up the mandrel while on rig or platform.

Well-bore fracturing

In one embodiment swivel tool 100 can be used in well bore fracturing process.

"Hydraulic fracturing," sometimes simply referred to as "fracturing," is a common stimulation treatment. A treatment fluid for this purpose is sometimes referred to as a "fracturing fluid." The fracturing fluid is pumped at a high flow rate and high pressure down into the wellbore and out into the formation. The pumping of the fracturing fluid is at a high flow rate and pressure that is much faster and higher than the fluid can escape through the permeability of the formation. Thus, the high flow rate and pressure creates or enhances a fracture in the subterranean formation.

Creating a fracture means making a new fracture in the formation. Enhancing a fracture means enlarging a pre-existing fracture in the formation.

For pumping in hydraulic fracturing, a "frac pump" is used, which is a high-pressure, high-volume pump. Typically, a frac pump is a positive-displacement reciprocating pump. These pumps generally are capable of pumping a wide range of fluid types, including corrosive fluids, abrasive fluids and slurries containing relatively large particulates, such as sand. Using a frac pump, the fracturing fluid may be pumped down into the wellbore at high rates and pressures, for example, at a flow rate in excess of 100 barrels per minute (3,100 US gallons per minute) at a pressure in excess of 5,000 pounds per square inch ("psi"). The pump rate and pressure of the fracturing fluid may be even higher, for example, pressures in excess of 10,000 psi are not uncommon.

To fracture a subterranean formation typically requires hundreds of thousands of gallons of fracturing fluid. Further, it is often desirable to fracture at more than one downhole location. For various reasons, including the high volumes of fracturing fluid required, ready availability, and historically low cost, the fracturing fluid is usually water or water-based. Thus, fracturing a well may require millions of gallons of water.

When the formation fractures or an existing fracture is enhanced, the fracturing fluid suddenly has a fluid flow path through the crack to flow more rapidly away from the wellbore. As soon as the fracture is created or enhanced, the sudden increase in flow of fluid away from the well reduces the pressure in the well. Thus, the creation or enhancement of a fracture in the formation is indicated by a sudden drop in fluid pressure, which can be observed at the well head.

After it is created, the newly-created fracture will tend to close after the pumping of the fracturing fluid is stopped. To prevent the fracture from closing, a material must be placed in the fracture to keep the fracture propped open. This material is usually in the form of an insoluble particulate, which can be suspended in the fracturing fluid, carried downhole, and deposited in the fracture. The particulate material holds the fracture open while still allowing fluid flow through the permeability of the particulate. A particulate material used for this purpose is often referred to as a "proppant." When deposited in the fracture, the proppant forms a "proppant pack," and, while holding the fracture apart, provides conductive channels through which fluids may flow to the wellbore. For this purpose, the particulate is typically selected based on two characteristics: size range and strength.

During wellbore fracturing operations the annular blowout preventer 70 is closed to maintain pressure while fracturing operations are performed. However, during fracturing operations the string of piping/tubing/drill string 85 is moved longitudinally and/or rotated relative to the closed annual blow out preventer 70.

However, this vertical movement creates a problem with extreme frictional drag involved with closing the annular blowout preventer 70 rubber seal element 71 on the drill pipe 85. The reason this is a problem is that during wellbore fracturing the drill pipe 85 must be stripped upwards through the closed annular seal 71 which tends to damage to the annular seal 71. Damage risks increase where tool joints (i.e., portions of the string having larger diameters) are stripped through the closed annular seal 71.

In one embodiment, for a fracturing job, the number of zones and lengths of each zone can be identified in order to determine the amount of stroke length required for a fracturing job. In this embodiment, swivel tool 100 can be used in string 85 where the annular blow out 70 preventer is closed on sleeve 300. In this embodiment the length of the mandrel 110 required to achieve the required stroke length for overall traversing of formation zones between mandrel 110 and sleeve 300 can be calculated.

There is long felt but unsolved need to have a swivel tool 100 including a mandrel 110 that can be made up to a desired length while at the rig 10 to accommodate fracturing operations. There is long felt but unsolved need to have a swivel tool 100 including a mandrel 110 that is shearable relative to a plurality of stacked ram type blow out preventers 2000 regardless of the position of the mandrel 110 relative to the stack of ram type blow out preventers 2000.

In one embodiment the mandrel 110 can be configured to a predetermined length off site from the well 10 to be fractured to the length required to achieve the calculated stroke length required, and then mandrel 110 is transported to rig 10.

In one embodiment the mandrel 110 can be made up onsite at rig 10, during the tripping in process, to a predetermined selected stroke length for the well to be fractured to achieve the calculated required stroke length.

Example Fracturing Job:

If 1,000 foot stroke length is calculated as being required for a job to cover the estimated zones, the actual stroke length of the mandrel 110 can include a 50% factor of safety for stroke length making the nominal stroke length of 1,500 feet. This factor of safety can be used to account for possible miscalculations while spacing out.

In one embodiment, the swivel tool 100 with stroking mandrel 110 can be partially made up at a site remote from rig 10. In one embodiment swivel tool 100 partially being made up includes the bottom latch sub 1100 and at least one stroking mandrel joint 1000 with the sleeve/housing 300 being slidably connected to this mandrel 110 and placed in a quick lock condition for transport.

On the top of the mandrel 110 will be a pin by box elevator sub 160. In addition a plurality of mandrel joints are included (both box by box and pin by pin).

Below the swivel can be the bottom hole assembly for performing downhole fracturing operations.

In one embodiment the rotating and reciprocating swivel tool 100 can be lowered from the rig floor F into the riser 80. In one embodiment the sleeve/housing 300 is lowered in a quick locked condition relative to mandrel 110.

In one embodiment, as the swivel tool 100 is being lowered the stroke length of the swivel tool 100 can be increased to a desired stroke length. As the swivel tool 100 is being lowered additional joints of mandrel 110 can be added to the mandrel 110 to obtain the desired stroke length between the sleeve/housing 300 and the mandrel 110. After the number of joints of mandrel 110 to obtain the desired stroke length are attached the makeup of the swivel tool 100 is completed by attaching the limiting sub 500 (with limiting shoulder 570) to the top of made up mandrel 110 thereby creating the desired stroke length.

The swivel tool 100 is continued to be lowered by now adding joints of pipe (e.g., drill pipe) while lowering the entire string 85. After this, during the continued process of lowering the swivel tool 100, joints of piping/tubing/drill string can be added while the swivel tool 100 is being lowered to where the annular blow out preventer 70 (i.e., annular seal) is closed on the sleeve 300.

In one embodiment the swivel tool 100 is lowered until the sleeve/housing 300 has passed below the annular blow out preventer 70, and then the sealing element 71 of the annular blow out preventer 70 is at least partially closed on mandrel 110 before the swivel tool 100 is raised slowly until the top of the sleeve/housing 300 contacts the bottom of the sealing element 71 of the annular blow out preventer 70.

Next, the sealing element 71 is opened and the sleeve/housing 300 is raised and positioned such that the external sealing area (e.g., the area between catches 326,328) of the sleeve/housing 300 is located adjacent the sealing element 71 of the annular blow out preventer 70, and the sealing element 71 of the annular blow out preventer 70 is at least partially closed on the sealing area of the sleeve 300.

Next, the sleeve/housing 300 is raised until the base of the lower catch 328 contacts the bottom of the sealing element 71. Next, the sealing element 71 is fully closed on the sealing surface of the sleeve 300.

Next the string 85 (including mandrel 110) is lowered relative to the sleeve/housing 300 to longitudinally unlock the sleeve/housing 300 relative to the mandrel 110.

Next, downhole operations can be begun while the sealing element 71 of the annular blow out preventer 70 remains sealed against the sleeve/housing 300.

During these subsequent downhole operations the mandrel 110 (and attached string 85) can be stroked and/or rotated relative to the sleeve/housing 300 without the closed sealing element 71 of the annular blow out preventer 70 seeing any differential movement thereby protecting the sealing element 71 from damage.

Once the sleeve/housing 300 of the swivel tool 100 is located in the closed annular blow out preventer 70, downhole operations (e.g., fracturing operations) can be started by lowering the 1,500 foot stroke length of the mandrel 110 from its uppermost stroke position (where the sleeve/housing 300 is in its longitudinally locked position) to any desired lower position of the attached wellbore fracturing tools (up to the mandrel's lowermost stroking position where sleeve contacts shoulder 570). The longitudinal movement of the mandrel 110 (and attached string 85) relative to the sleeve 300 can be at the operator's desired speed, and can include rotation of the mandrel 110 (and attached string 85) relative to the sleeve/housing 300 if desired by the operator.

Once the wellbore fracturing tools are in place then the zones of the formation can be isolated relative to the fracturing tool (by conventional methods) and fracturing pumping can commence.

Once the sand slurry (with contained proppant) is completely pumped into the zone to be fractured, pumping can be stopped, and the wellbore fracturing tools with attached string 85 and mandrel 110 lifted up the wellbore 40 to the next zone. During this step the stroking mandrel 110 is raised relative to the sleeve/housing 300 which sleeve/housing 300 is continued to be sealed upon by the annular sealing element 70.

Once the tools are located in the next zone above then, the same operation of pumping is repeated for each zone moving up the wellbore 40.

Benefits of the swivel tool 100 include but are not limited to:

(1) no differential movement between the annular seal 71 and any item being raised or lowered in the wellbore 40 while the annular seal 71 remains closed on the sleeve/housing 300;

(2) no stripping of tool joints through a closed annular blowout preventer 70.

Once multiple zones have been fractured, the job is complete, while the seal 71 remains closed on sleeve 300, mandrel 110 can be raised relative to the sleeve/housing 300 until the sleeve/housing 300 enters a latched state at the upper portion of the stroke length of the mandrel 110. Next, the sealing element 71 of the annular blow out preventer 70 can be opened and the swivel tool 100 with attached string 85 tripped out of the hole 40.

<u>Equipment needed to run special drill pipe</u>

- Box/female by box/female joints (e.g., 600, 800, 1000, etc.) of mandrel 110 of tubular/piping (which preferably are about 30 feet in overall length).
- Pin/male by pin/male mandrel tubular/piping tool joints (e.g., 700, 900, etc.) of tubular/piping (which preferably are about 30 inches in overall length, and include a recessed elevator groove e.g., 706, 906, etc.)
- Pup joints (e.g. joint 2100 in figures 54, 55, 58, and 51) for lifting and handling the mandrel 110 during make-up and break-out at rig 10.
- False rotary
- 2-sets of special 5" elevators
- Special non-scaring make-up tongs
- Hand operated strap tongs
- Stabbing guide
- Hand file
- Scouring pads
- Cleaning solvents
- Dope

While certain novel features of this invention shown and described herein are pointed out in the annexed claims, the invention is not intended to be limited to the details specified, since a person of ordinary skill in the relevant art will understand that various omissions, modifications, substitutions and changes in the forms and details of the device illustrated and in its operation may be made without departing in any way from the spirit of the present invention. No feature of the invention is critical or essential unless it is expressly stated as being "critical" or "essential."

The following is a parts list of reference numerals or part numbers and corresponding descriptions as used herein:

LIST FOR REFERENCE NUMERALS

Reference Numeral	Description
10	drilling rig/well drilling apparatus
22	drilling fluid or mud
40	well bore
70	annular blowout preventer
71	annular seal unit
75	stack
80	riser
85	drill or work string
87	seabed
88	well head
90	upper volumetric section
92	lower volumetric section
100	swivel
110	mandrel
126	upper end
128	lower end
300	swivel sleeve or housing
310	interior section
315	gap
326	upper catch, shoulder, flange

328	lower catch, shoulder, flange
350	Ls - - overall length of sleeve or housing with attachments on upper and lower ends
370	first seal
380	second seal
500	upper stroke limiting mandrel joint
510	longitudinal passage
512	diameter of longitudinal passage
520	upper end
522	threads
530	lower end
532	threads
533	tapered shoulder
538	recess for seal
539	enlarged area of recess for seal
550	seal
552	first end
553	widened area of seal
555	second end of seal
556	tapered area of seal
557	vertical area of seal
570	shoulder
600	double box end mandrel joint
601	exterior sealing surface
602	interior surface
604	wall thickness
610	longitudinal passage
612	inner diameter
620	upper end
621	tapered shoulder
622	threads

623	tapered area
630	lower end
632	threads
633	tapered area
660	shoulder
670	arrow
672	arrow
700	double pin end mandrel joint
701	exterior sealing surface
704	wall thickness
706	recessed area
710	longitudinal passage
712	diameter
720	upper end
721	tapered shoulder
722	threads
723	tapered shoulder
728	recess for first seal
729	widened area of first recess
730	lower end
731	tapered shoulder
732	threads
733	tapered shoulder
738	recess for second seal
739	widened area of second recess
740	upper taper
742	transition insert
746	lower transition
748	transition insert
750	first seal
752	first end

753	widened area of first seal
755	second end of first seal
756	tapered area of first seal
757	vertical area of first seal
760	second seal
770	inner diameter
774	outer diameter
800	double box end mandrel joint
801	exterior sealing surface
802	interior surface
804	wall thickness
810	longitudinal passage
812	inner diameter
820	upper end
830	lower end
850	seal
900	double pin end mandrel joint
901	exterior sealing surface
906	recessed area
910	longitudinal passage
920	upper end
923	tapered shoulder
930	lower end
933	tapered shoulder
1000	double box end mandrel joint
1001	exterior sealing surface
1004	wall thickness
1010	longitudinal passage
1012	inner diameter
1020	upper end
1030	lower end

1100	lower shouldered mandrel joint
1110	longitudinal passage
1112	inner diameter
1120	upper end
1122	threads
1128	recess for seal
1129	enlarged area of recess for seal
1130	lower end
1132	threads
1150	seal
1153	widened area of seal
1155	second end of seal
1156	tapered area of seal
1157	vertical area of seal
1200	limiting shoulder
1300	locking shoulder
1400	recessed area for relaxing internal pressure between sleeve and mandrel
1500	female adjustable sealing unit
1502	exterior surface
1510	longitudinal passage
1520	first end
1522	reduced inlet
1530	second end
1532	enlarged inlet
1534	tapered section
1540	recess for seal
1544	vertical section
1546	tapered area
1550	diameter of recess
1552	outer diameter of recess

1554	inner diameter of recess
1560	O-ring recess
1562	O-ring
2000	plurality of ram blow out preventers
2010	first ram blow out preventer
2012	arrow
2020	second ram blow out preventer
2022	arrow
2030	third ram blow out preventer
2032	arrow
2040	fourth ram blow out preventer
2042	arrow
2050	distance between first and second rams
2052	distance between first and third rams
2054	distance between third and fourth rams
2056	distance between second and fourth rams
2058	distance between second and third rams
2100	lifting sub
2500	double pin end mandrel joint
2506	recessed area in external sealing surface
2600	double box end mandrel joint
2700	double pin end mandrel joint
2706	recessed area in external sealing surface
2800	double box end mandrel joint
2900	double pin end mandrel joint
2906	recessed area in external sealing surface
3000	double box end mandrel joint
3001	arrow indicating downward movement
3002	arrow indicating downward movement
3003	arrow indicating downward movement
3004	arrow indicating downward movement

3005	arrow indicating downward movement
3010	arrow indicating upward movement
3011	arrow indicating upward movement
3012	arrow indicating upward movement
3013	arrow indicating upward movement
3014	arrow indicating upward movement
3015	arrow indicating upward movement
3100	double pin end mandrel joint
3106	recessed area in external sealing surface
ABOP	annular blow out preventer
BJ	ball joint
BL	booster line
CM	choke manifold
CL	choke line
CM	choke manifold
D	diverter
DL	diverter line
F	rig floor
IB	inner barrel
KL	kill line
MP	mud pit
MB	mud gas buster or separator
OB	outer barrel
R	riser
RAM BOP	ram blow out preventer
RF	flow line
S	floating structure or rig
SJ	slip or telescoping joint
SS	shale shaker

All measurements disclosed herein are at standard temperature and pressure, at sea level on Earth, unless indicated otherwise. All materials used or intended to be used in a human being are biocompatible, unless indicated otherwise.

It will be understood that each of the elements described above, or two or more together may also find a useful application in other types of methods differing from the type described above. Without further analysis, the foregoing will so fully reveal the gist of the present invention that others can, by applying current knowledge, readily adapt it for various applications without omitting features that, from the standpoint of prior art, fairly constitute essential characteristics of the generic or specific aspects of this invention set forth in the appended claims. The foregoing embodiments are presented by way of example only; the scope of the present invention is to be limited only by the following claims.

CLAIMS

We claim:

1. A method of creating a rotating and reciprocating swivel tool while located on a drilling rig or platform having a specified stroke length, comprising the steps of:

(a) providing a swivel tool, the swivel tool comprising a mandrel and a sleeve/housing, the mandrel being rotatable and reciprocable relative to the sleeve/housing, the mandrel having a first stroke length relative to the sleeve/housing;

(b) supporting in a substantially vertical direction the swivel tool at the rig;

(c) adding a mandrel joint to the top of the mandrel, such additional joint increasing the stroking length of the mandrel relative to the first stoking length;

(d) lowering the swivel tool and again supporting in a vertical direction the swivel tool in a substantially vertical direction on the rig; and

(e) repeating steps "c" and "d" until the final stroking length of the mandrel relative to the sleeve/housing is at least 100 feet.

2. The method of claim 1, wherein steps "c" and "d" can be repeated until the final stroking length can be greater than about 150 feet.

3. The method of claim 1, wherein steps "c" and "d" can be repeated until the final stroking length can be greater than about 300 feet.

4. The method of claim 1, wherein steps "c" and "d" can be repeated until the final stroking length can be greater than about 500 feet.

5. The method of claim 1, wherein steps "c" and "d" can be repeated until the final stroking length can be greater than about 1000 feet.

6. The method of claim 1, wherein steps "c" and "d" can be repeated until the final stroking length can be greater than about 1500 feet.

7. The method of claim 1, wherein in step "e" a plurality of the mandrel joints include at least one recessed area in the exterior sealing surface, and during step "c" one of these recessed areas are used to support the swivel tool in a substantially vertical direction on the rig.

8. The method of claim 7, wherein at least one of the recessed areas includes soft material transition sections.

9. The method of claim 7, wherein the upper portions of the recessed areas are be frustoconical.

10. The method of claim 7, wherein the upper portions of the recessed areas are tapered.

11. A mandrel pin and box end assembly for joining mandrel joint ends having a longitudinal flow passage therethrough having a longitudinal axis, comprising:

first and second joints of mandrel,

the first joint having a pin end portion at one extremity,

the second joint having a box end portion at one extremity,

the pin end portion having a pin end annular planer face, and annular groove opening to the annular planer face, the pin annular groove having a longitudinal axis which is parallel to the longitudinal axis of the longitudinal flow passage;

the box end portion having a box end annular planer face, and annular groove opening to the annular box face, the box annular groove having a longitudinal axis which is parallel to the longitudinal axis of the longitudinal flow passage;

the pin annular groove and box annular groove cooperating to define an annular sealing chamber;

the annular sealing chamber containing a cylindrical packing unit.

12. The assembly of claim 11, wherein the planer face of the box end portion is slidable along the longitudinal axis.

13. The assembly of claim 12, wherein the planer face of the box end portion is connected to the body of the box end joint using an interference fit.

14. The assembly of claim 11, wherein the packing unit has uncompressed and compressed states, and in an uncompressed state the packing unit has an inner radius equal to or less than the inner radius of the annular sealing chamber.

15. The assembly of claim 11, wherein the packing unit is resilient.

16. The assembly of claim 11, wherein the sealing chamber has a plurality of cylindrical walls which are nested with respect each other.

17. The assembly of claim 16, wherein one of the grooves of either the pin or box end groove has a tapered portion and a non-tapered portion, wherein the tapered portion is located farther away from the planer face than the non-tapered portion.

18. The assembly of claim 17, wherein the groove walls are tapered in the range of 1 to 10 degrees.

19. The assembly of claim 11, wherein the packing unit is symmetrical about its radial axis.

20. The assembly of claim 11, wherein the sealing chamber and the box and/or pin groove are symmetrical about a radial midplane.

21. The assembly of claim 11, wherein a gasket with a main body having first and second ends is contained in the annular pin and annular box grooves, wherein the main body of the gasket is axially compressed when positioned in the sealing chamber.

22. The assembly of claim 21, wherein the second end of the gasket has sharp corners and the box or pin groove has sharp corners adjacent the boreline wherein fluid entrapment is reduced.

23. The assembly of claim 21, wherein the main body of the gasket in an uncompressed state is generally rectangular in shape with radiused edges.

24. The assembly of claim 21, wherein the second end of the gasket in an uncompressed state is generally rectangular in shape with sharp corners.

25. The assembly of claim 21, wherein a radial width of the main body of the gasket in an uncompressed state is substantially equal to the radial width of the sealing chamber.

26. The assembly of claim 21, wherein an axial width of the main body of the gasket in an uncompressed state is greater than the axial width of the sealing chamber.

27. The assembly of claim 21, wherein an axial width of the second portion of the gasket in an uncompressed state is greater than the axial width of the groove.

28. A joint and seal ring assembly for joining and sealing threaded pipe or tube ends that define an axial flow passage therethrough, comprising:

first and second ends, each of the ends being at a respective one of the tube ends;

the axial flow passage having first and second internal diameters;

each end having opposed end faces with side walls cooperating to define an annular recess comprising a seal chamber and a circumferentially continuous groove opening radially inward from the seal chamber to the axial flow passage, the radial groove being positioned between the first and second internal diameters of the axial flow passage;

a gasket comprising a main body and a radially inward second portion in the uncompressed state; and

the main body of the gasket being positioned within the seal chamber.

29. The assembly of claim 28, wherein the gasket is resilient.

30. The assembly of claim 28, wherein the main body of the gasket in an uncompressed state has an inner radius equal to or less than the inner radius of the seal chamber wall forming an interference fit occurs.

31. A marine oil and gas well drilling apparatus comprising:

(a) a marine drilling platform;

(b) a drill string that extends between the marine drilling platform and a formation to be drilled, the drill string having a flow bore;

(c) a mandrel having upper and lower end sections and connected to and rotatable with upper and lower sections of the drill string, the mandrel having an external diameter and including a longitudinal passage forming a continuation of a flow bore of the drill string sections, the mandrel being comprised of at least one joint having double box ends with the joint being severable by a ram blow out preventer;

(d) a sleeve having a longitudinal sleeve passage and an internal diameter, the sleeve being rotatably connected to the mandrel; and

(e) an interstitial space between the internal diameter of the sleeve and the external diameter of the mandrel.

32. The apparatus of claim 31, wherein the mandrel includes two double box end joints which are connected by a double pin end sub.

33. A method of using a reciprocating swivel in a drill or work string, the method comprising the following steps:

(a) lowering a rotating and reciprocating tool to an annular blow out preventer, the tool comprising a mandrel and a sleeve, the sleeve being reciprocable relative to the mandrel and the mandrel including at least one joint having double box ends with the joint being severable by a ram blow out preventer, the sleeve having two spaced apart sealing units, the swivel including an interstitial space between the sleeve and the mandrel with first and second spaced apart sealing units each sealing the interstitial space;

(b) after step “a”, having the annular blow out preventer close on the sleeve; and

(c) after step “b”, causing relative longitudinal movement between the sleeve and the mandrel.

34. The method of claim 33, wherein in step “a” the mandrel includes two double box end joints which are connected by a double pin end sub, and in step “c” when the double pin end sub is at the same longitudinal position as the first sealing unit, the first sealing unit loses its seal of the interstitial space, but the second sealing keeps its seal of the interstitial space.

35. The method of claim 34, wherein after the double pin end sub passes by the first sealing unit, the first sealing unit regains its seal of the interstitial space.

36. The method of claim 35, wherein when the double pin end sub is at the same longitudinal position as the second sealing unit, the second sealing unit loses its seal of the interstitial space, but the first sealing keeps its seal of the interstitial space.

37. The method of claim 36, wherein after the double pin end sub passes by the second sealing unit, the second sealing unit regains its seal of the interstitial space.

38. The method of claim 33, wherein in step “a” the mandrel includes two double box end joints which are connected by a double pin end sub, and in step “c” when the double pin end sub is at the same longitudinal position as the second sealing unit, the second sealing unit loses its seal of the interstitial space, but the first sealing keeps its seal of the interstitial space.

39. The method of claim 38, wherein after the double pin end sub passes by the second sealing unit, the second sealing unit regains its seal of the interstitial space.

40. The method of claim 39, wherein when the double pin end sub is at the same longitudinal position as the first sealing unit, the first sealing unit loses its seal of the interstitial space, but the second sealing keeps its seal of the interstitial space.

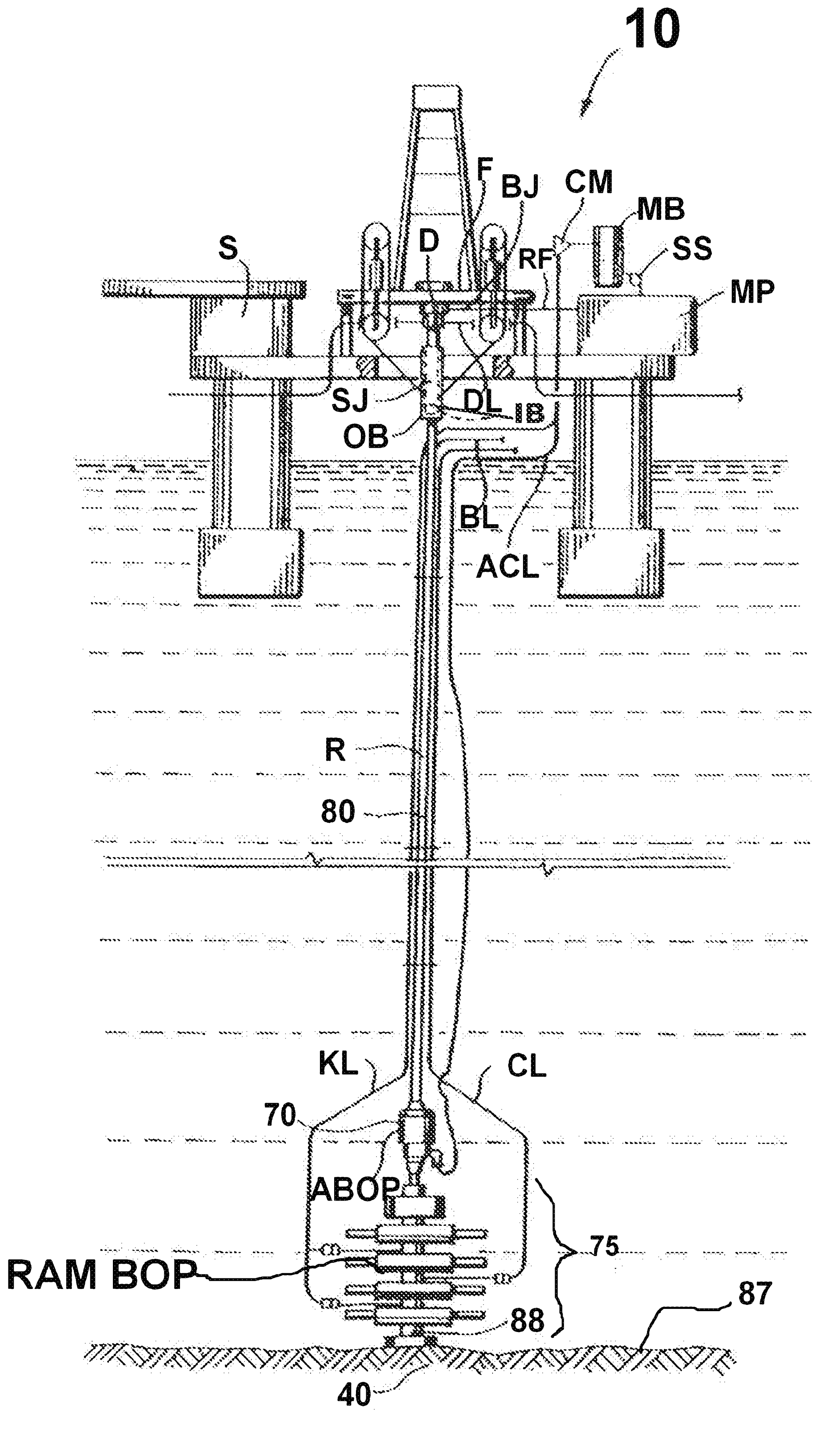
41. The method of claim 40, wherein after the double pin end sub passes by the first sealing unit, the first sealing unit regains its seal of the interstitial space.

42. The method of claim 41, further comprising the step of after step “c”, moving the sleeve outside of the annular blow out preventer.

43. The method of claim 42, further comprising the step of moving the sleeve back inside of the annular blow out preventer and having the annular blow out preventer close on the sleeve.

44. The method of claim 43, further comprising the step of, after moving the sleeve back inside the annular blow out preventer causing relative longitudinal movement between the sleeve and the mandrel and activating a quick lock/quick unlock system from an unlocked state to a locked state.

45. The invention as substantially disclosed and described.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BJ
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MB
D
S
RF
SS
MP
SJ
DL
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OB
BL
ACL
R
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KL
CL
70
ABOP
75
RAM BOP
87
88
40

FIG. 1

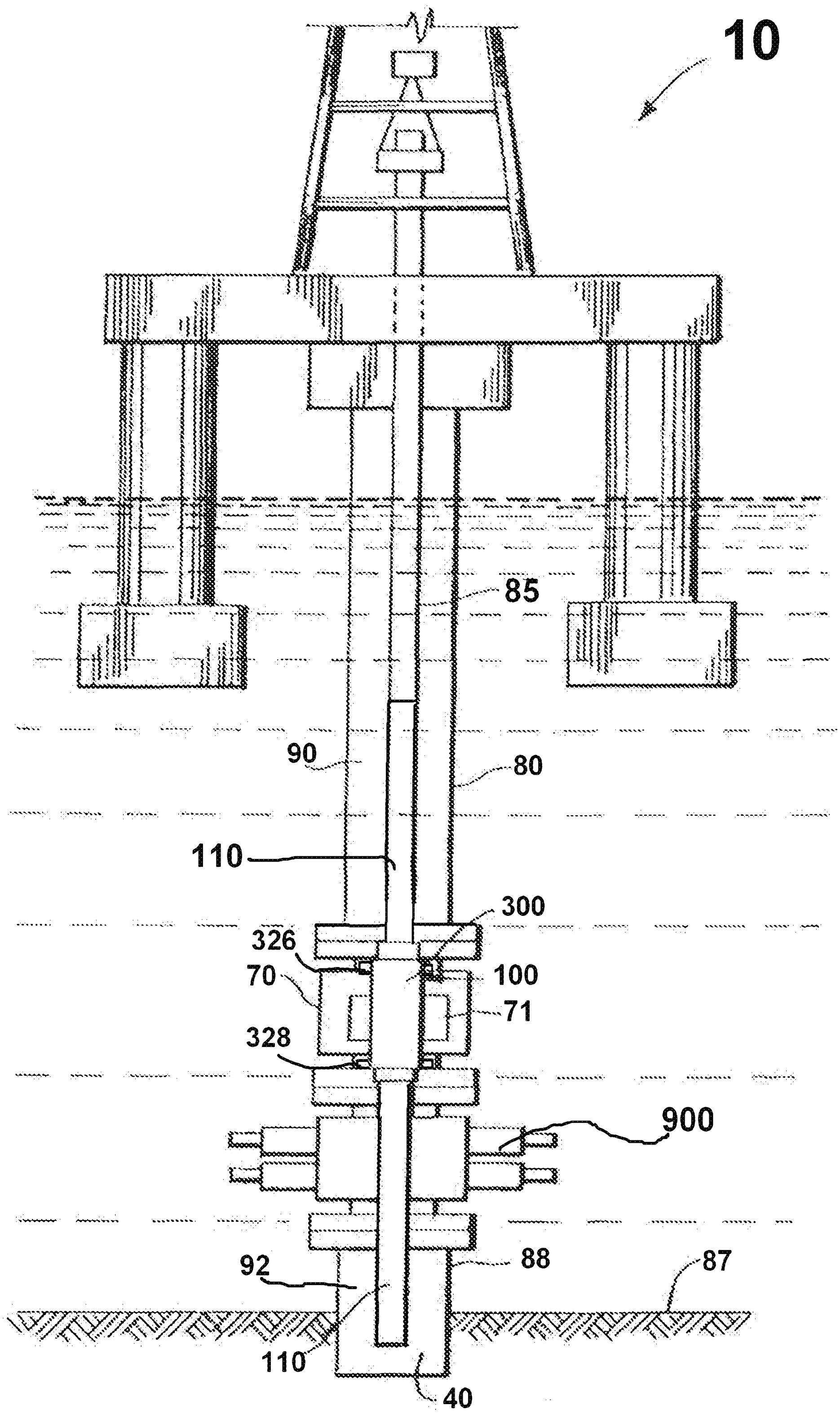
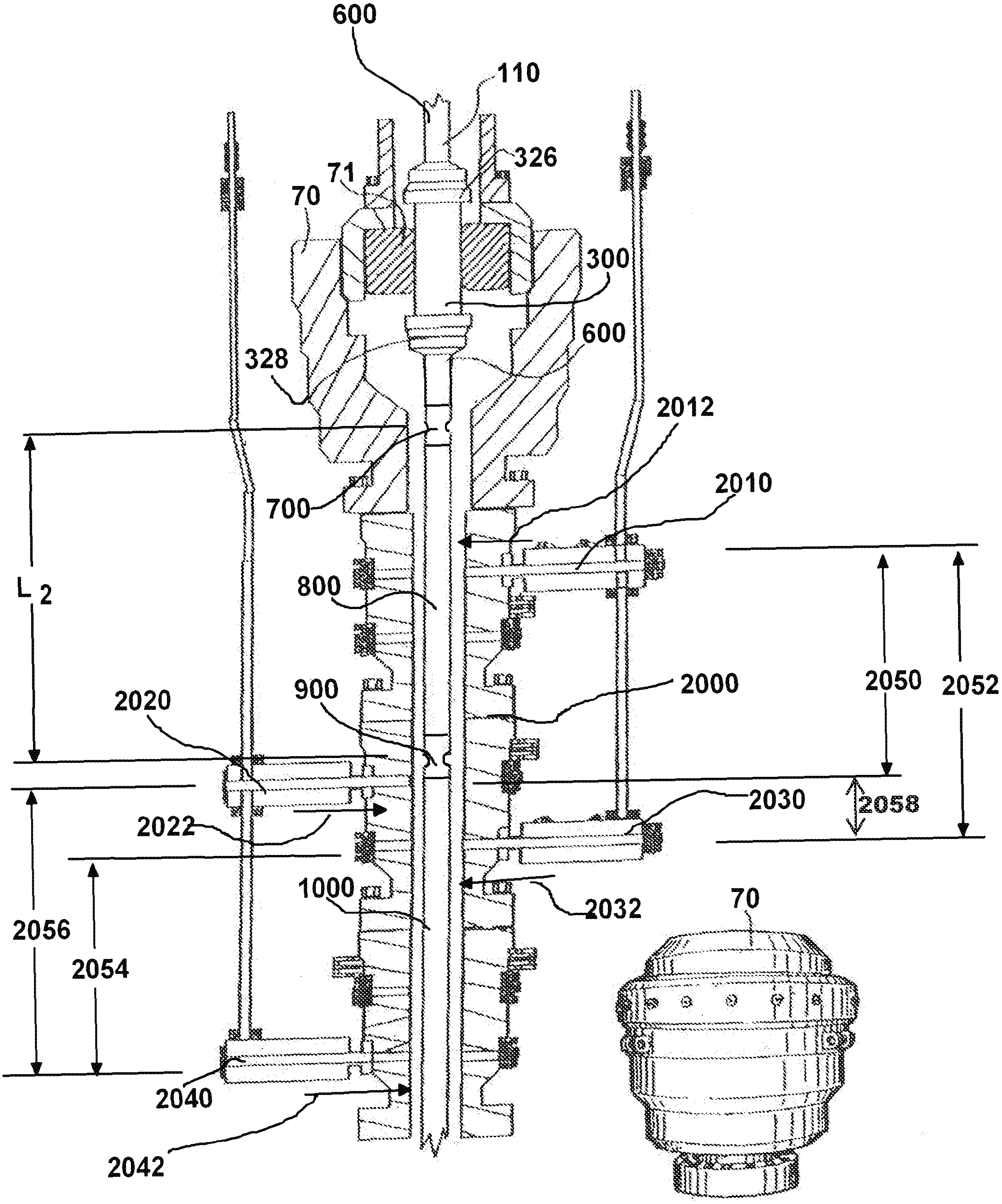


FIG. 2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L 2
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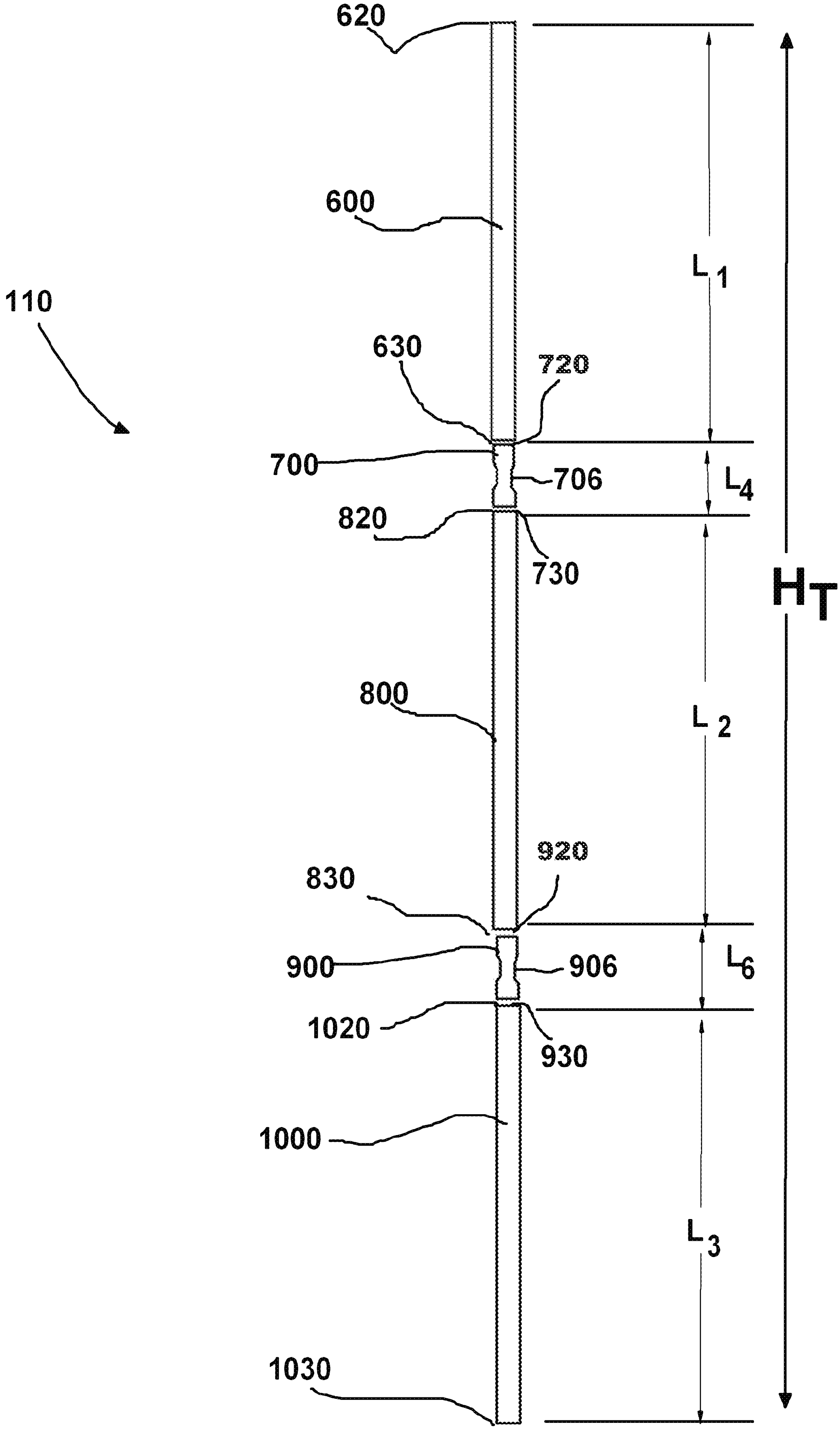
2032
2056
2054
2040
2042
70

FIG. 4

FIG. 3



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600
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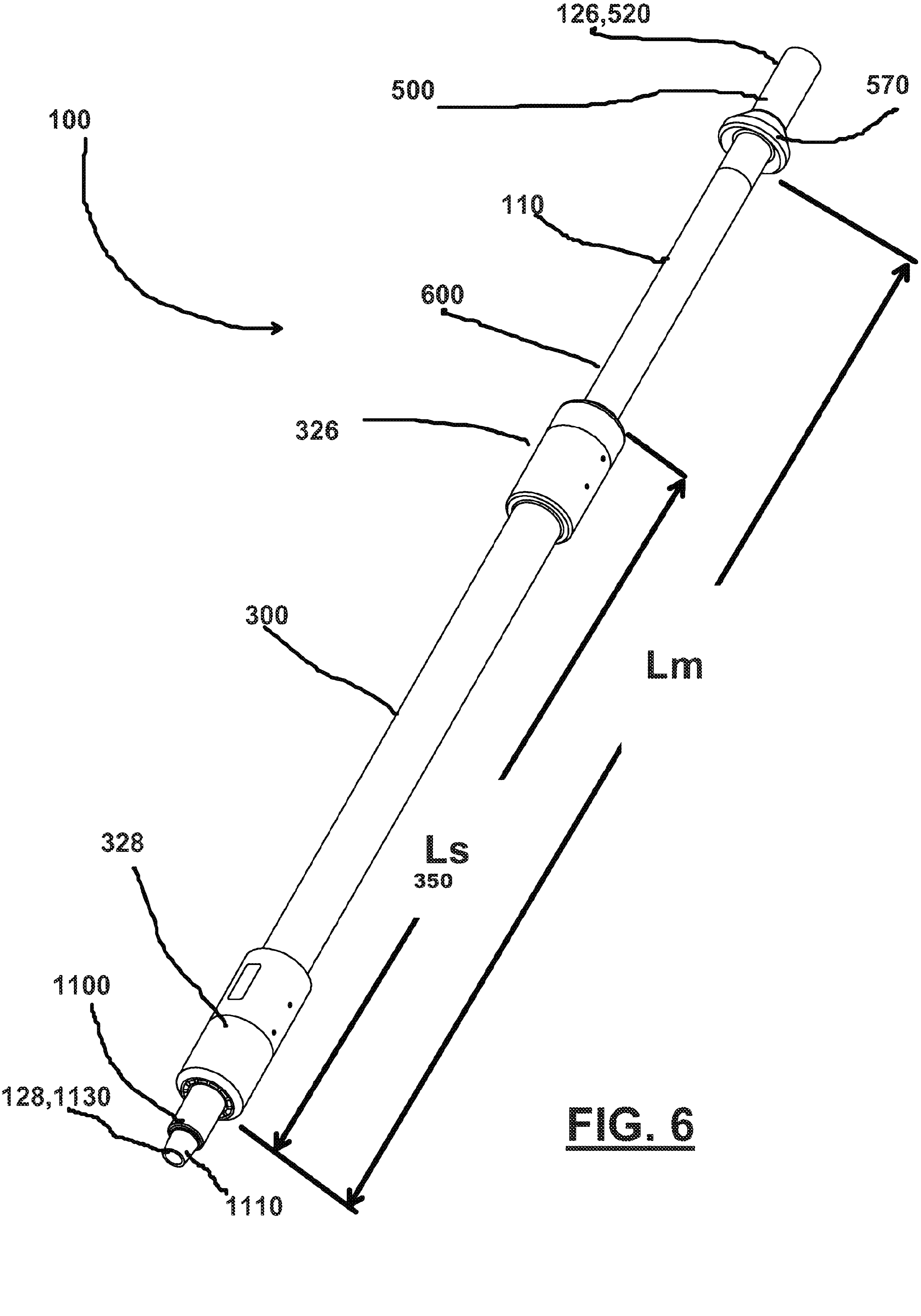
630
720
700
706
820
730
800
830
920
900
906
1020
930
1000
1030
L 1
L4
L 2
L6
L 3
HT

FIG. 5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326
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Ls
350
328
1100
128,1130
1110

FIG. 6

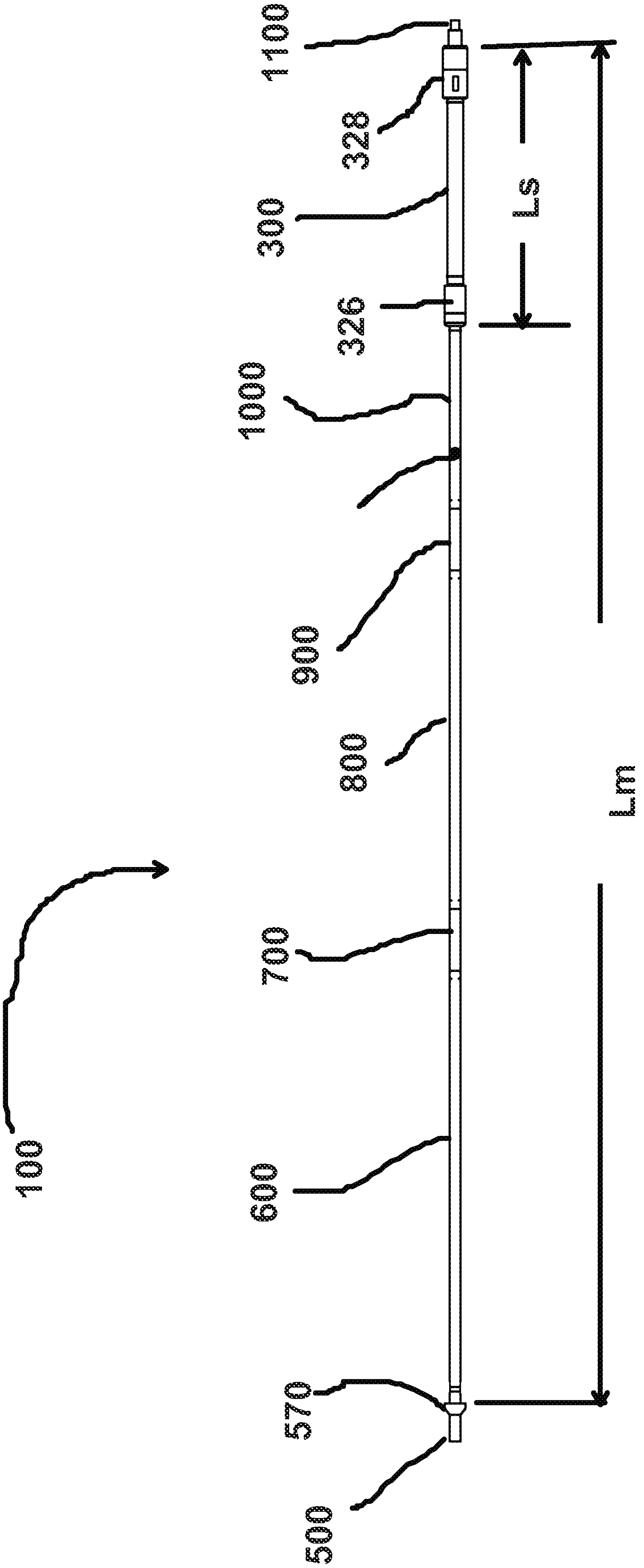

FIG. 7

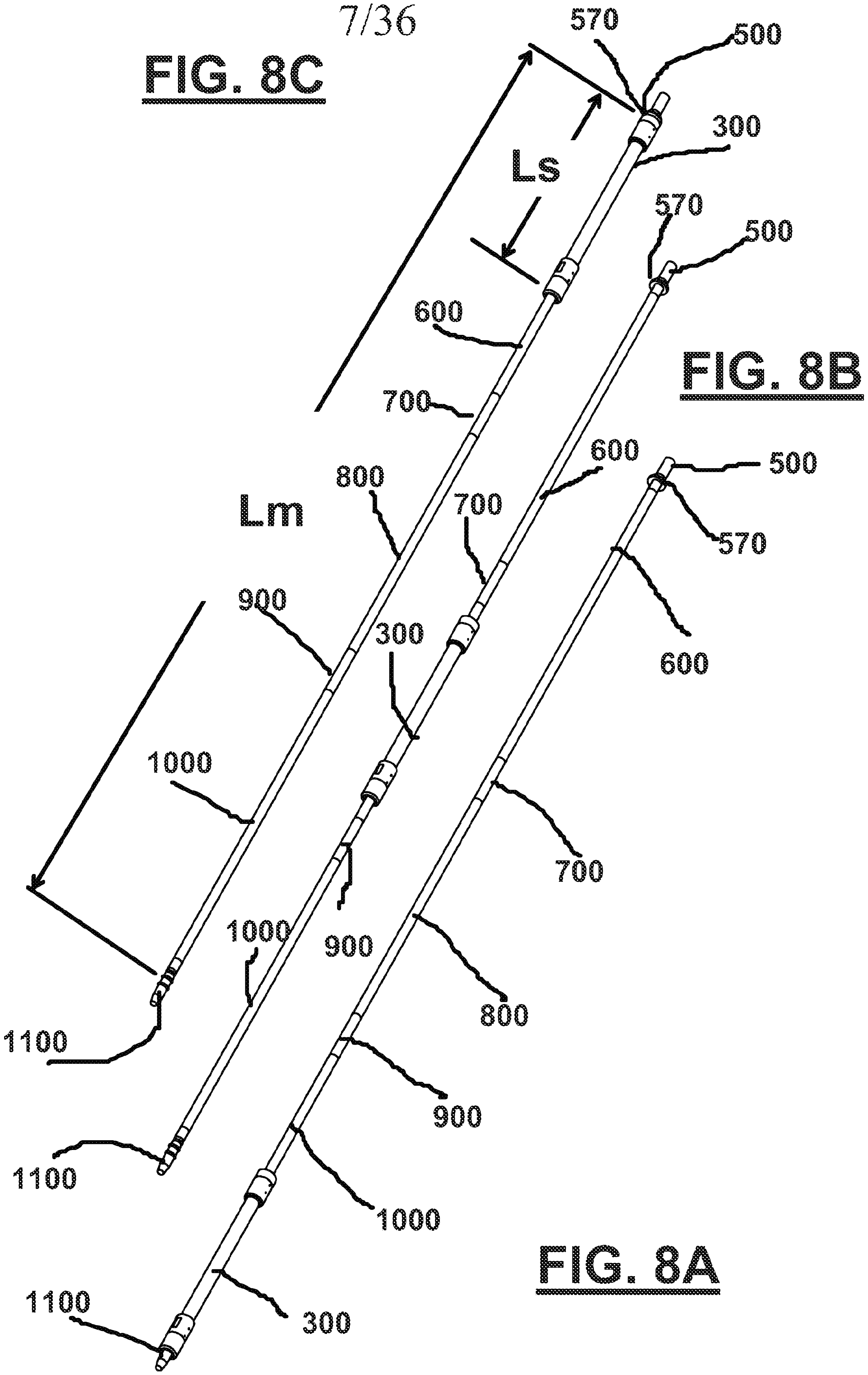
FIG. 8C
570
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300
Ls
Lm
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700
800
900
1000
1100
FIG. 8B
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700
300
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1100
500
570
600
700
800
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1000
300
1100
FIG. 8A

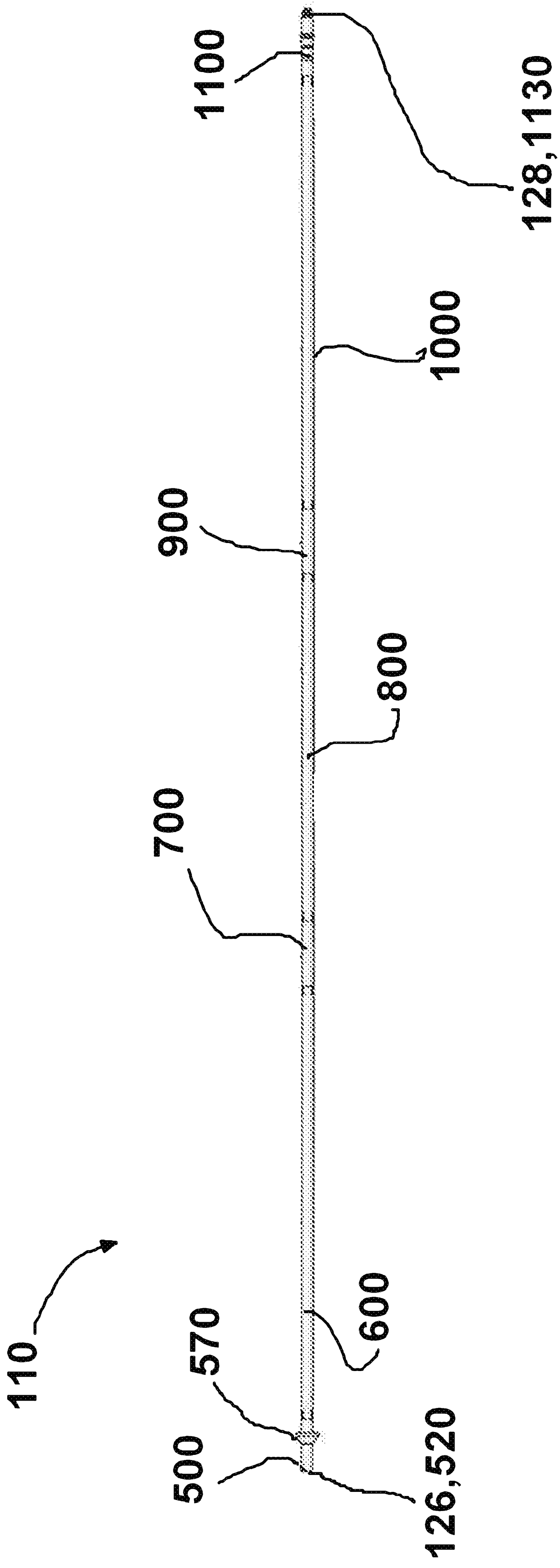


FIG. 9

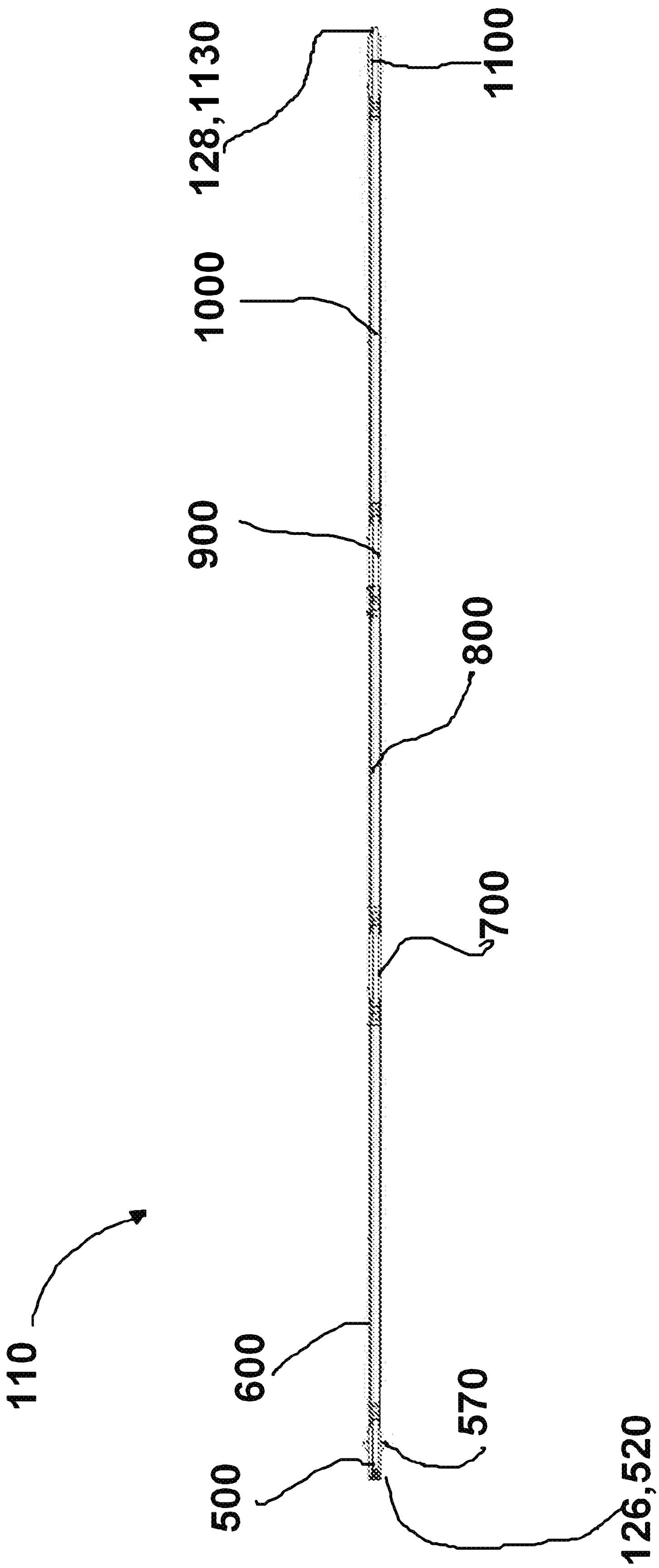


FIG. 10

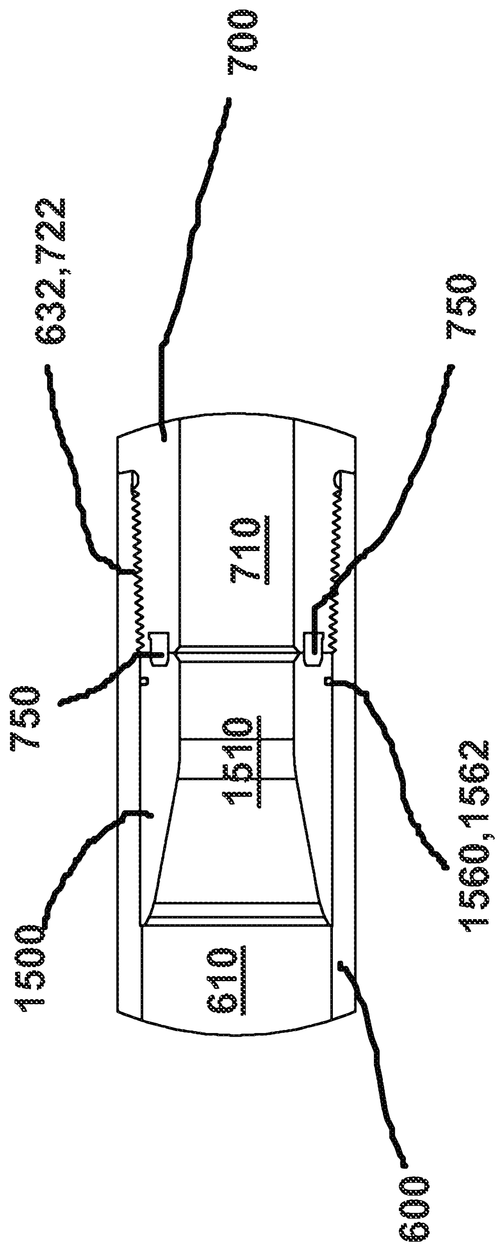


FIG. 11A

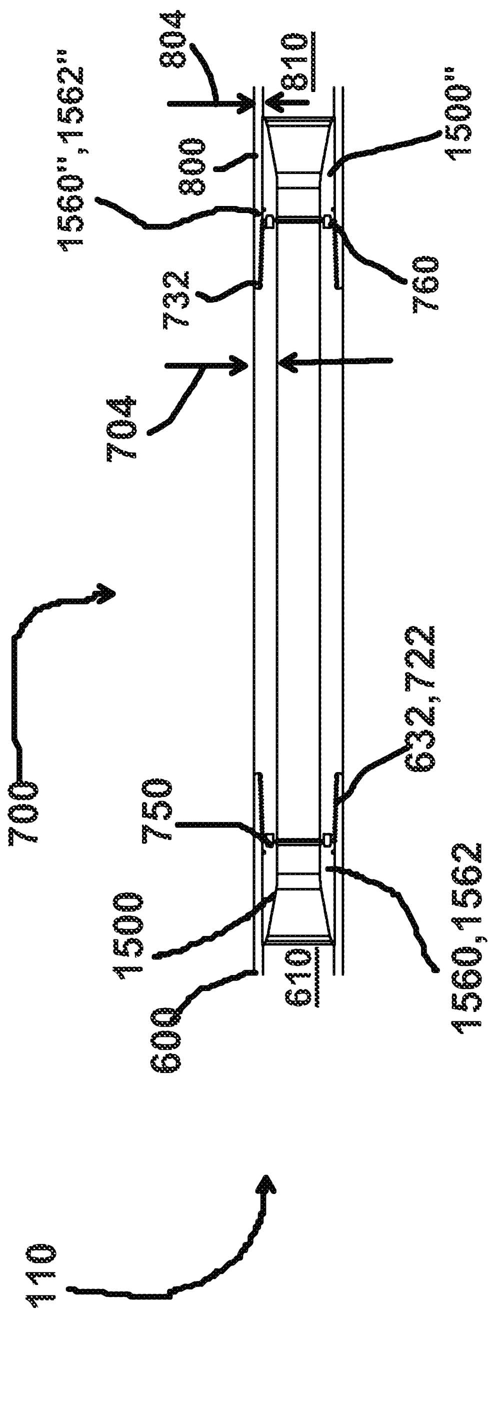


FIG. 12

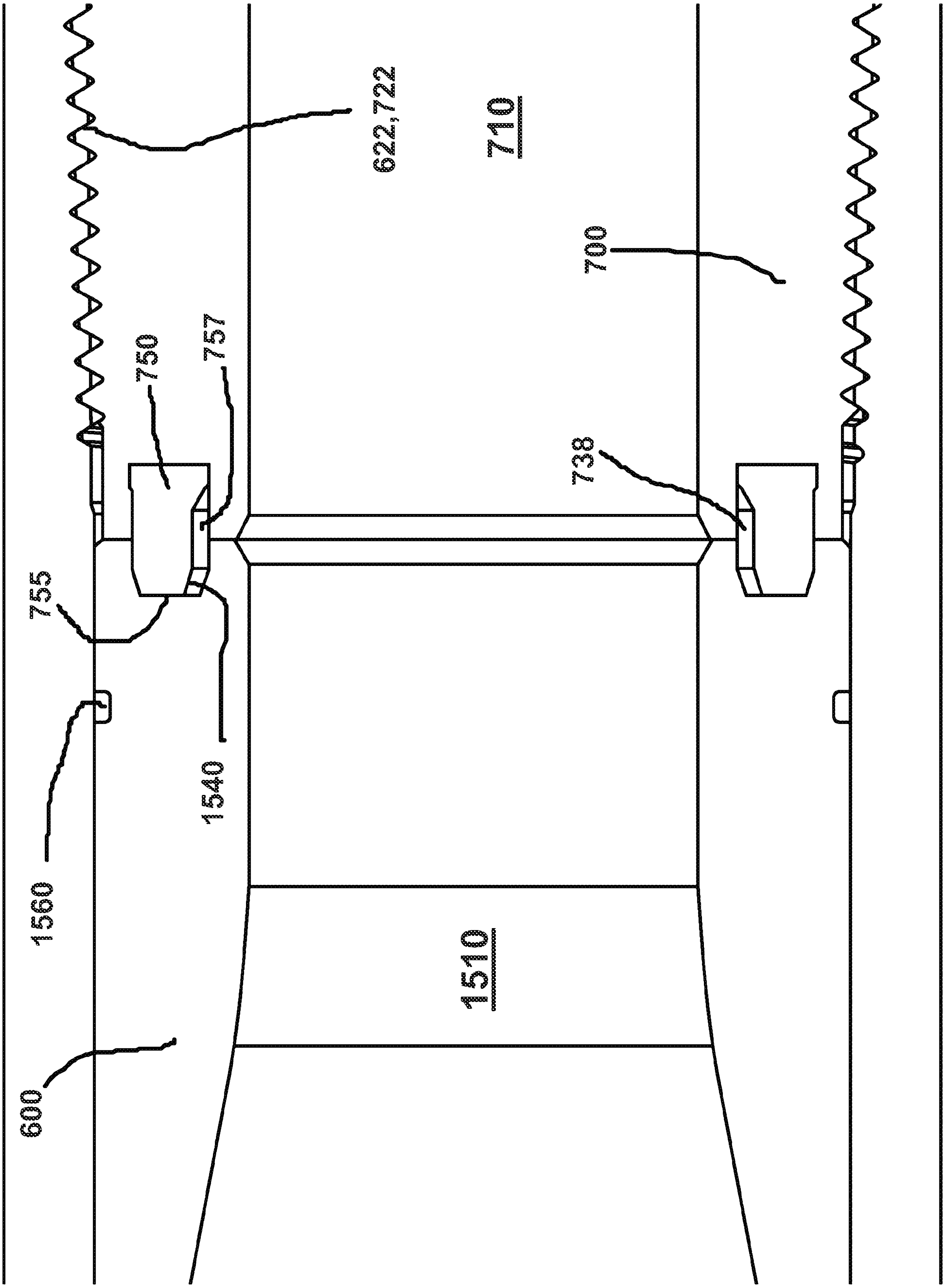


FIG. 11B

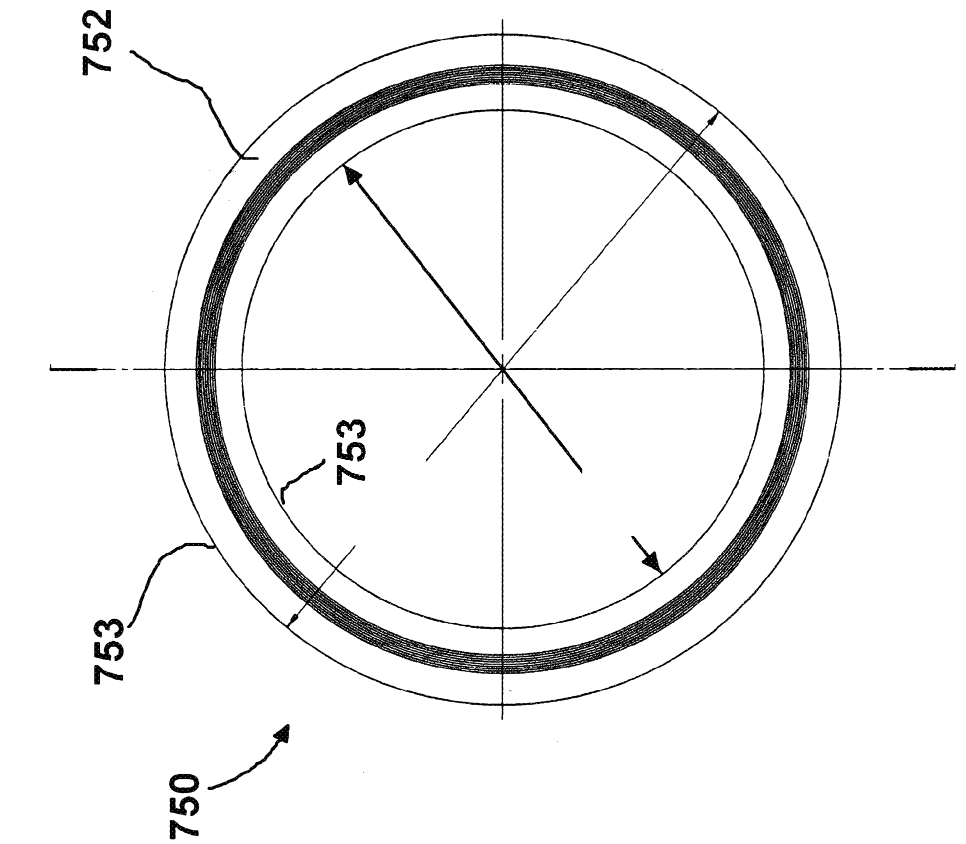


FIG. 13

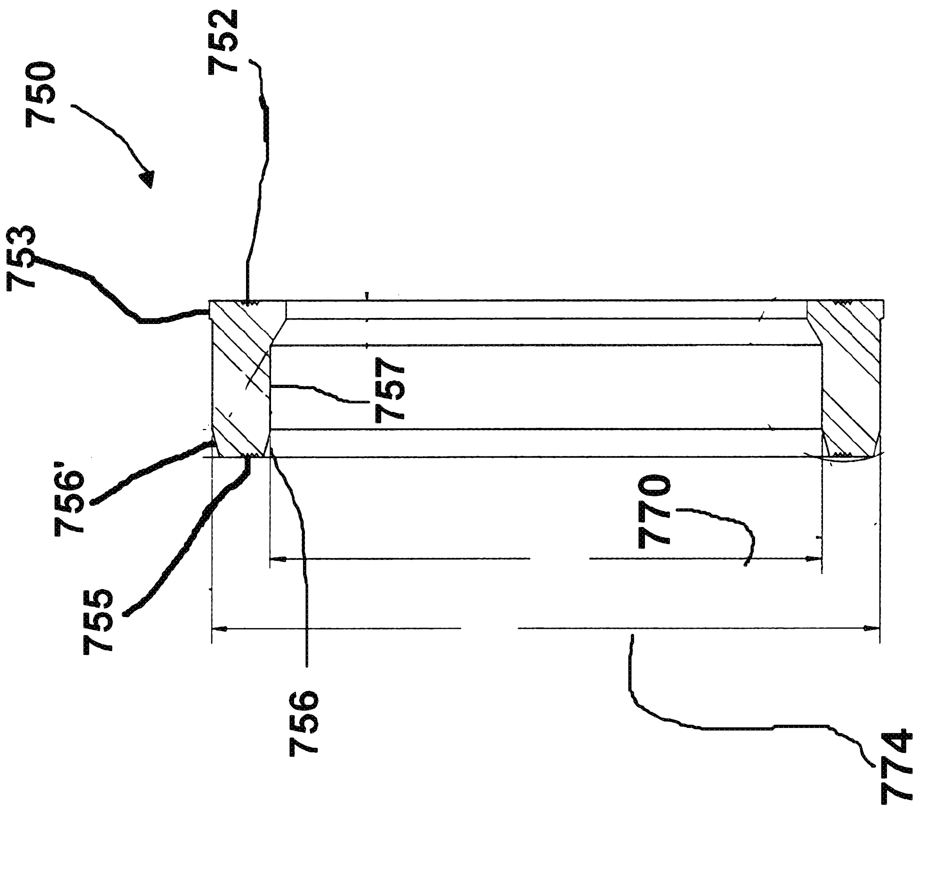


FIG. 14

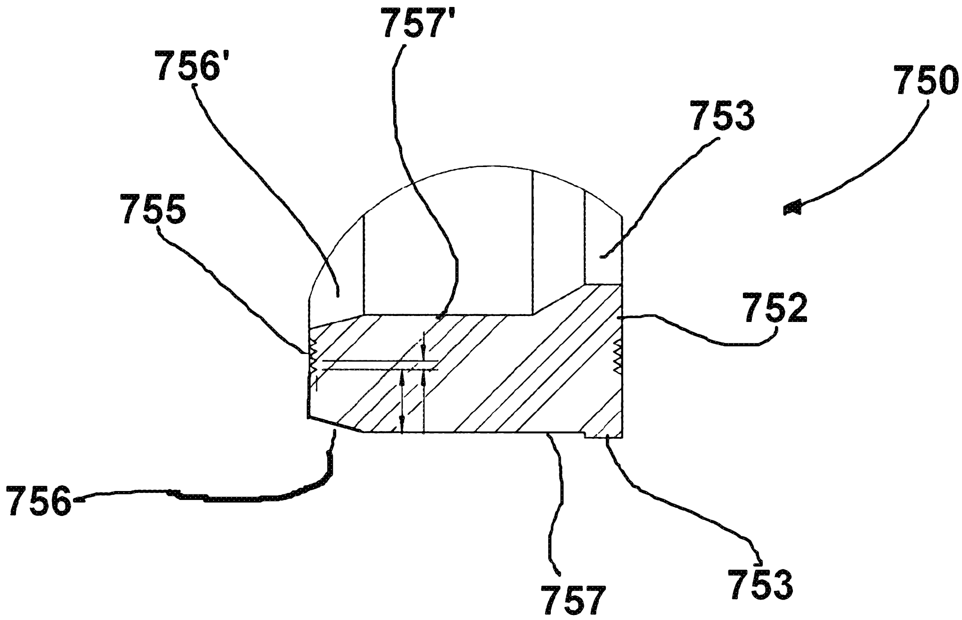
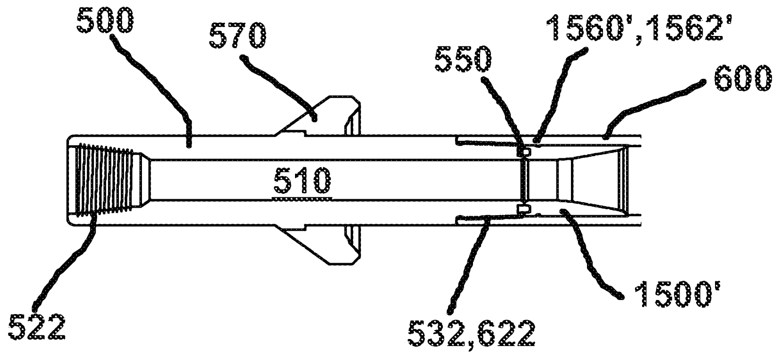


FIG. 15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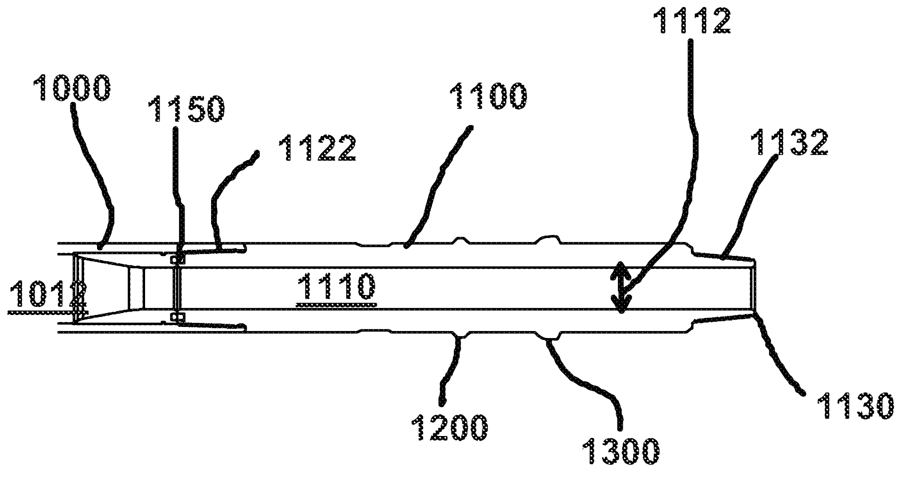
600
510
522
532,622
1500'

FIG. 16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1300
1130

FIG. 17

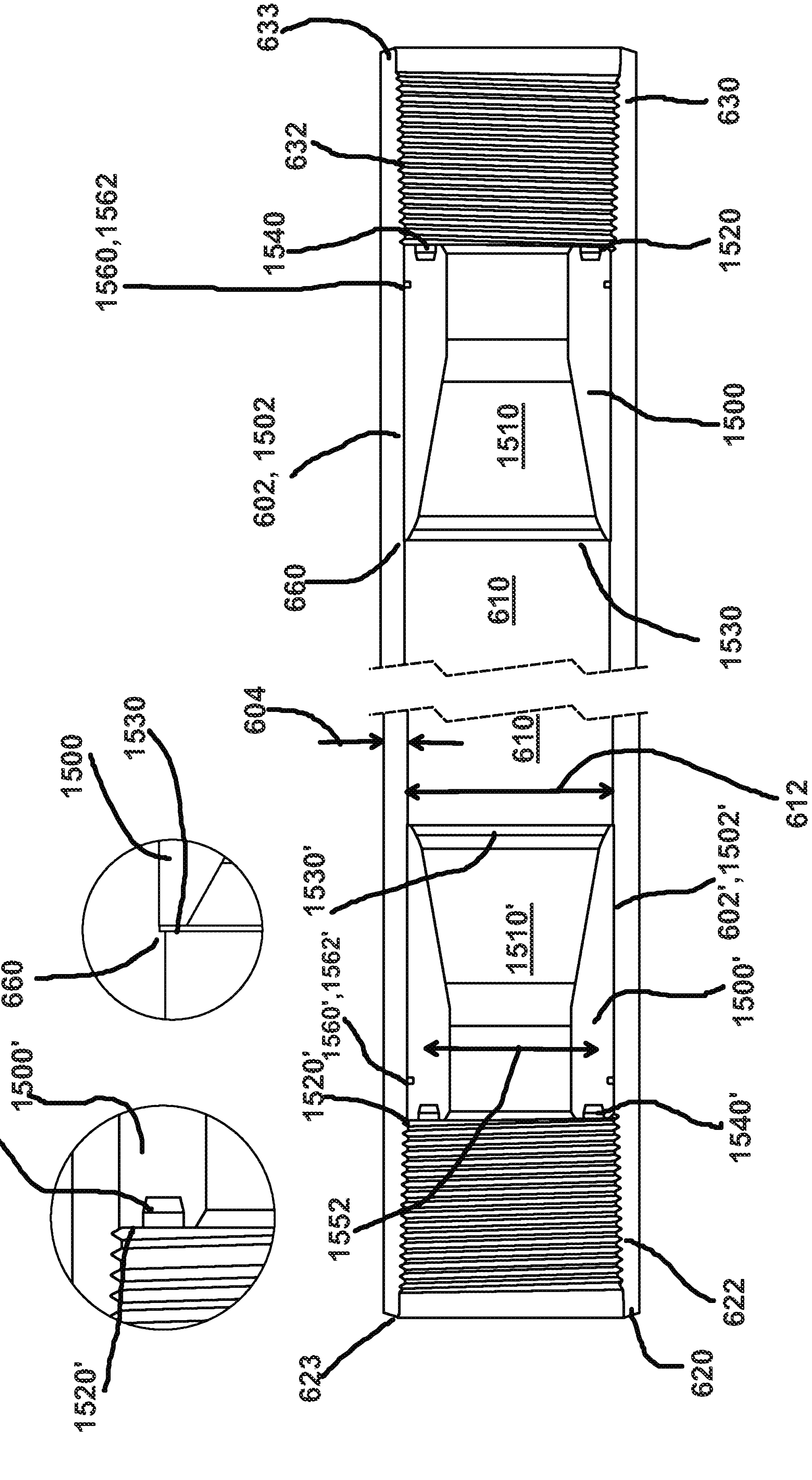

FIG. 18

FIG. 19

FIG. 20

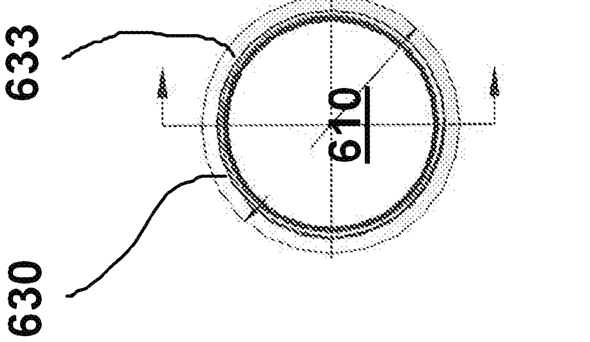

FIG. 22

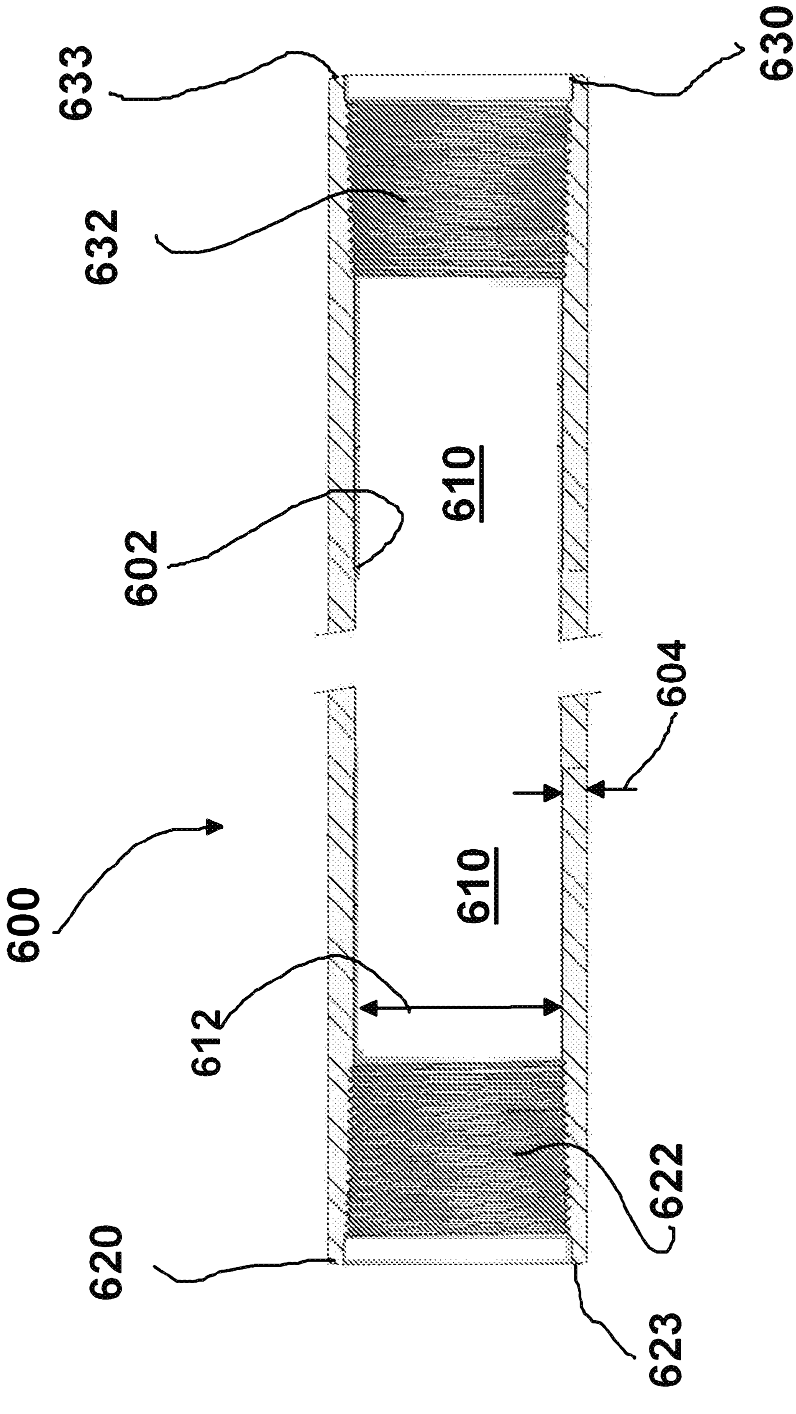

FIG. 21

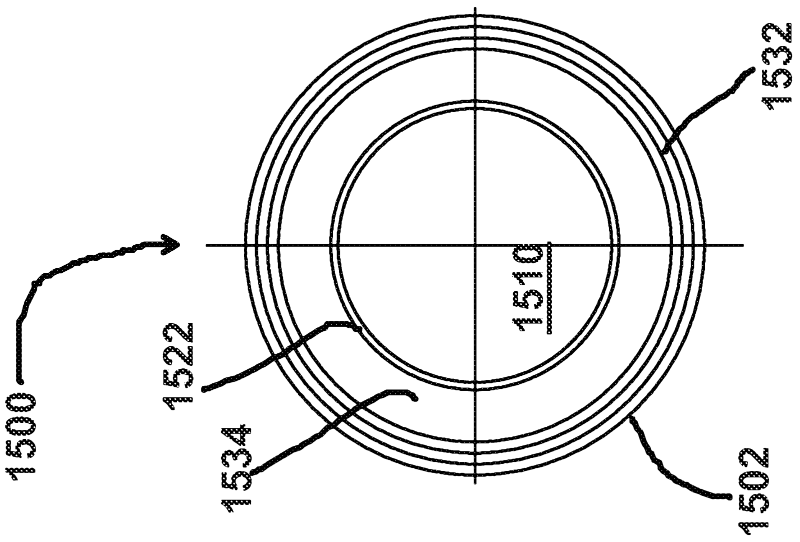
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FIG. 24

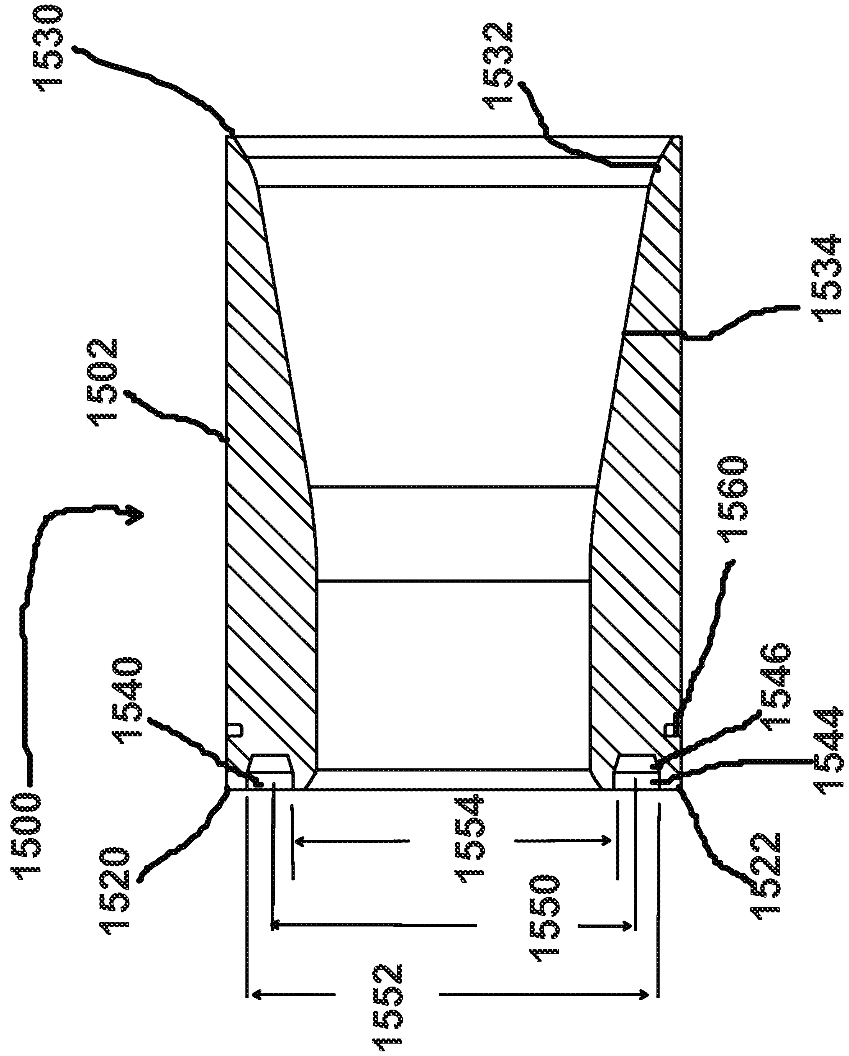
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FIG. 23

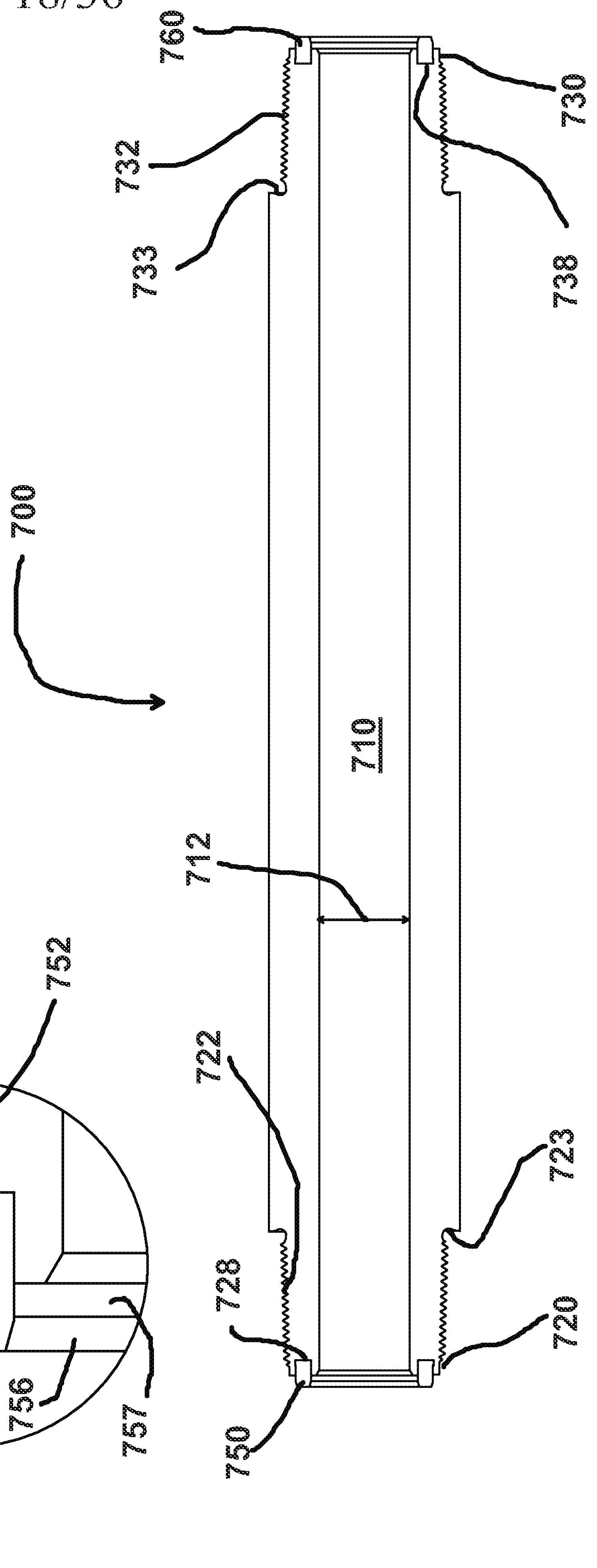
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FIG. 25

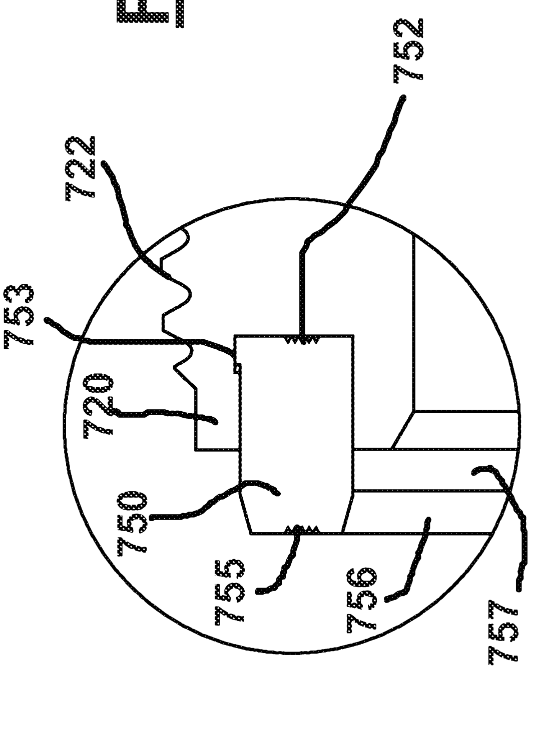
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FIG. 26

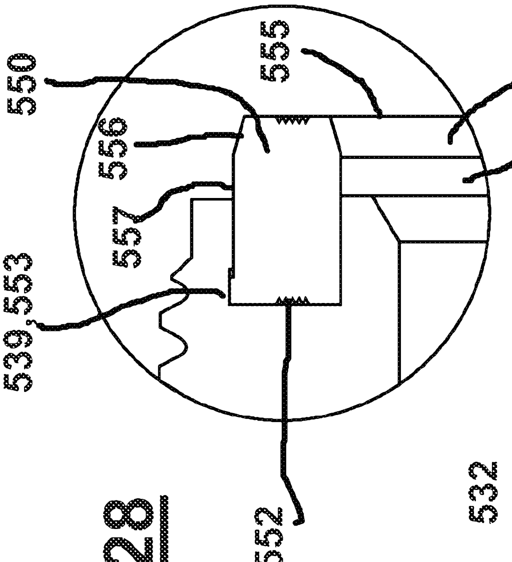
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FIG. 28

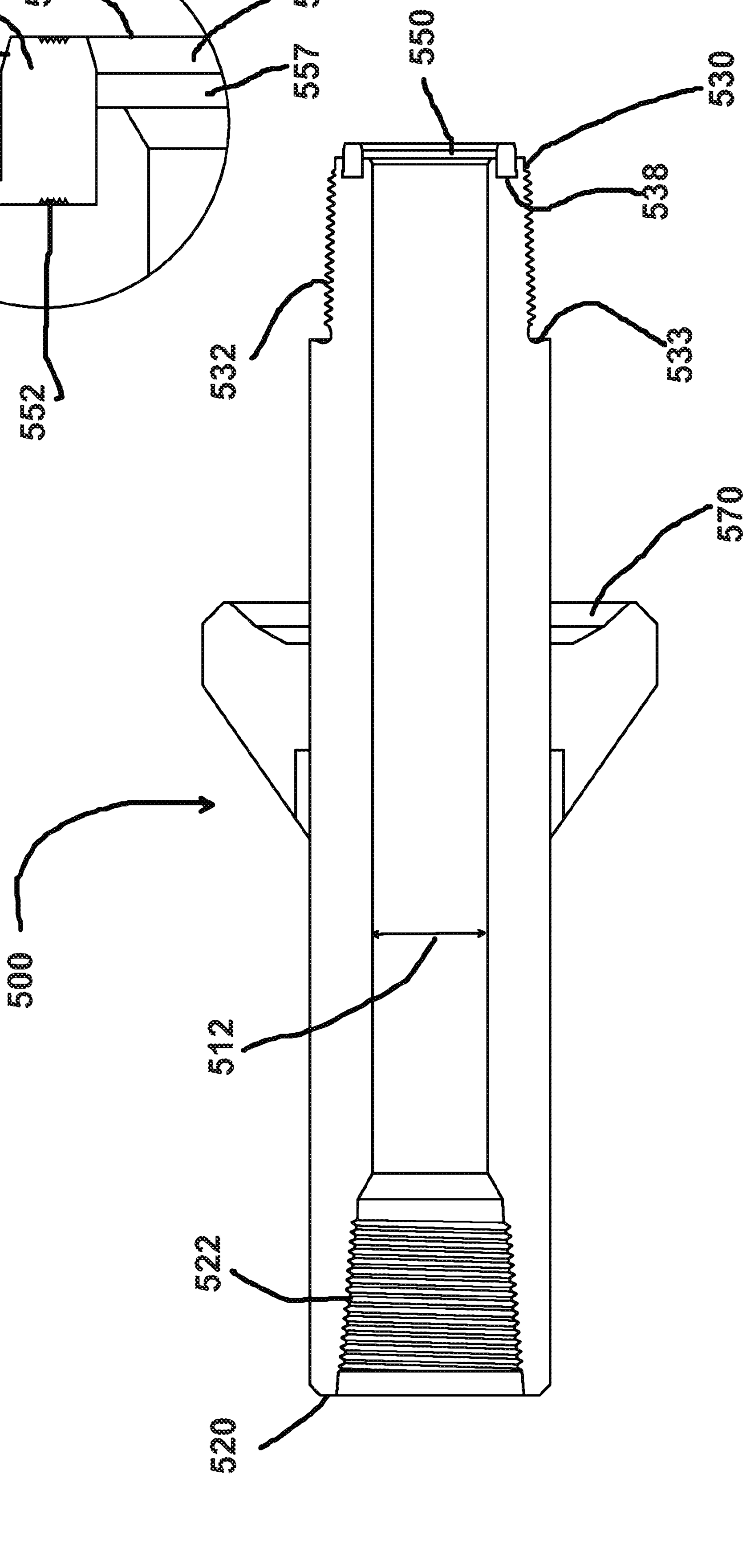
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FIG. 27

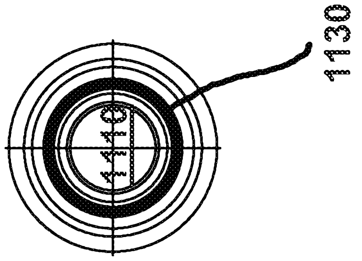


FIG. 31

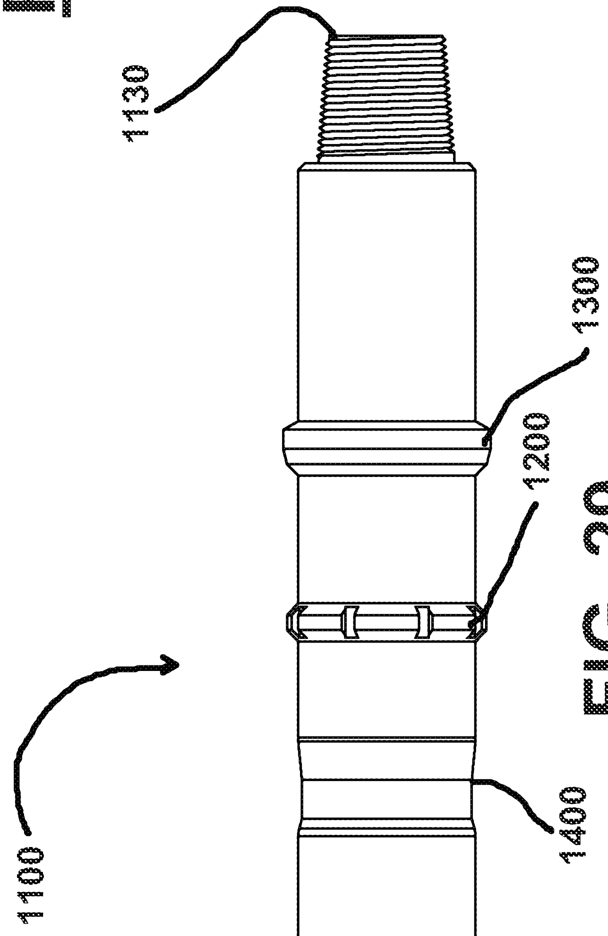


FIG. 29

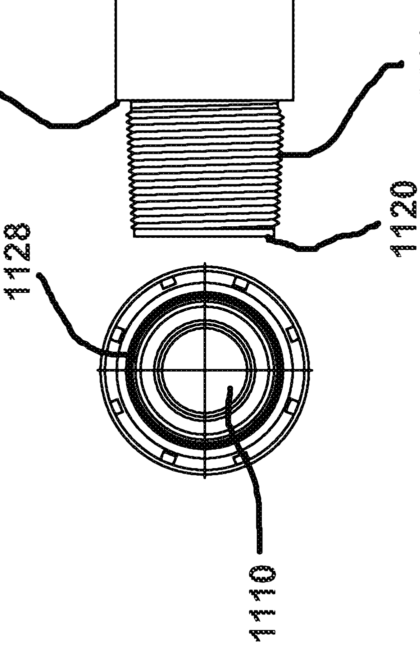


FIG. 30

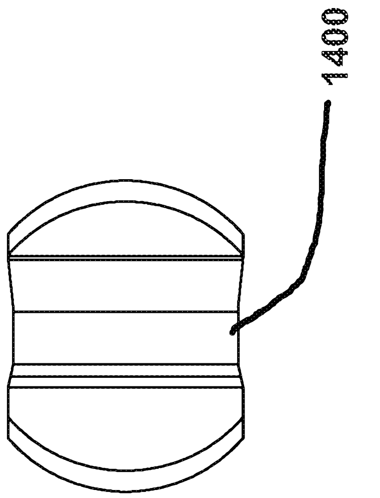
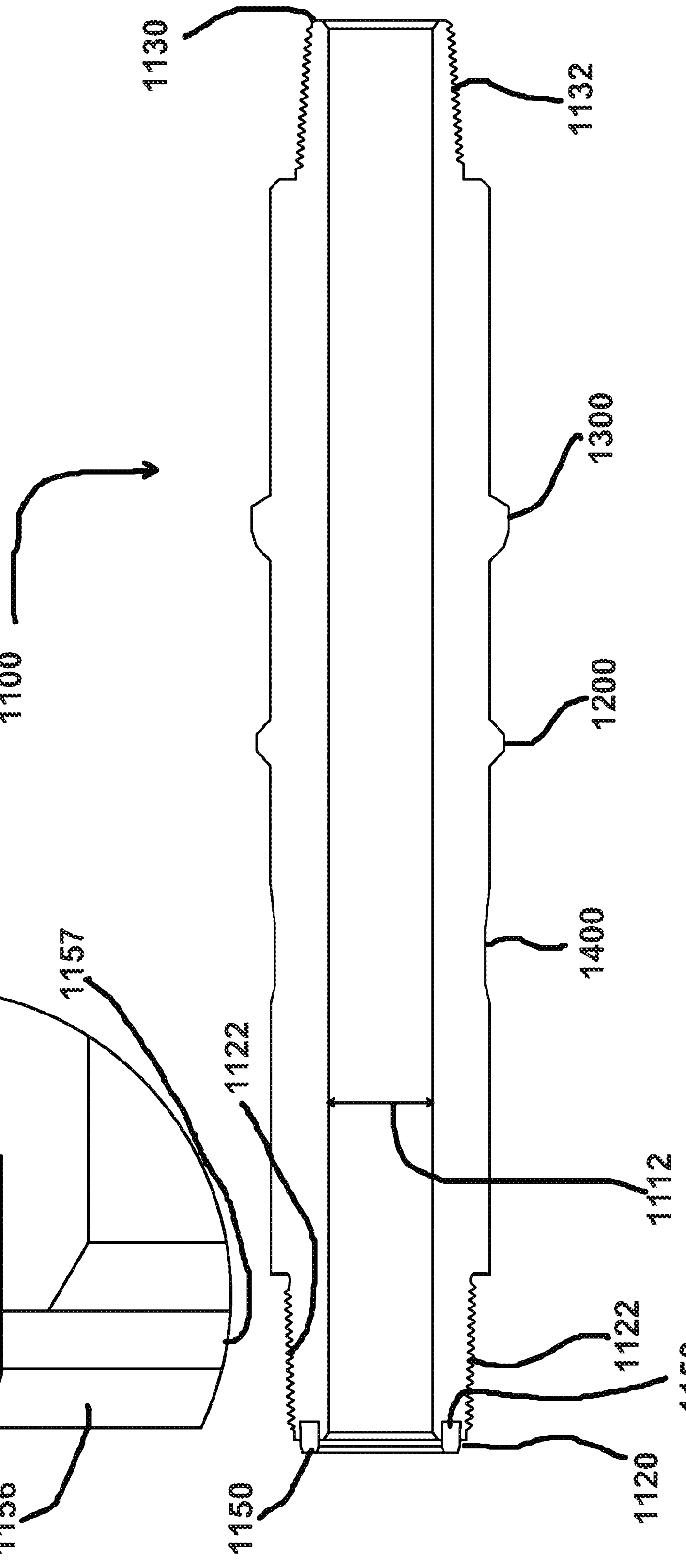


FIG. 32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1150
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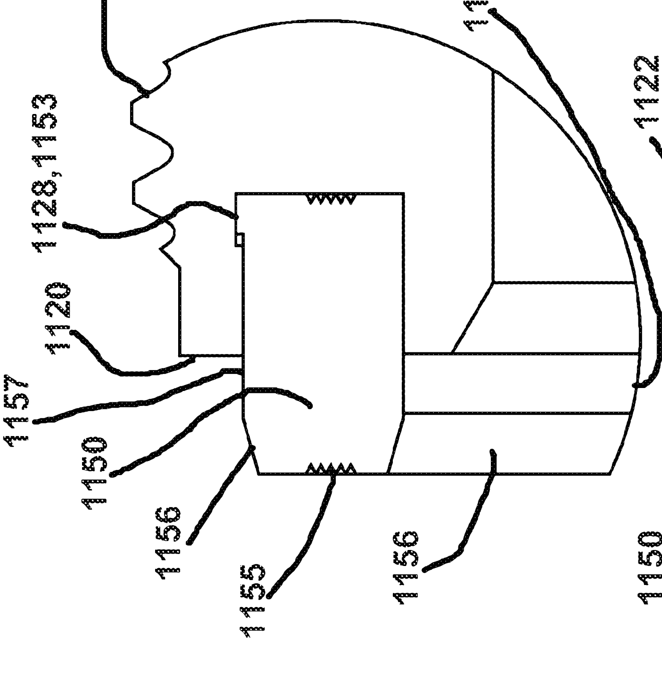
FIG. 33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1155
1156

FIG. 34

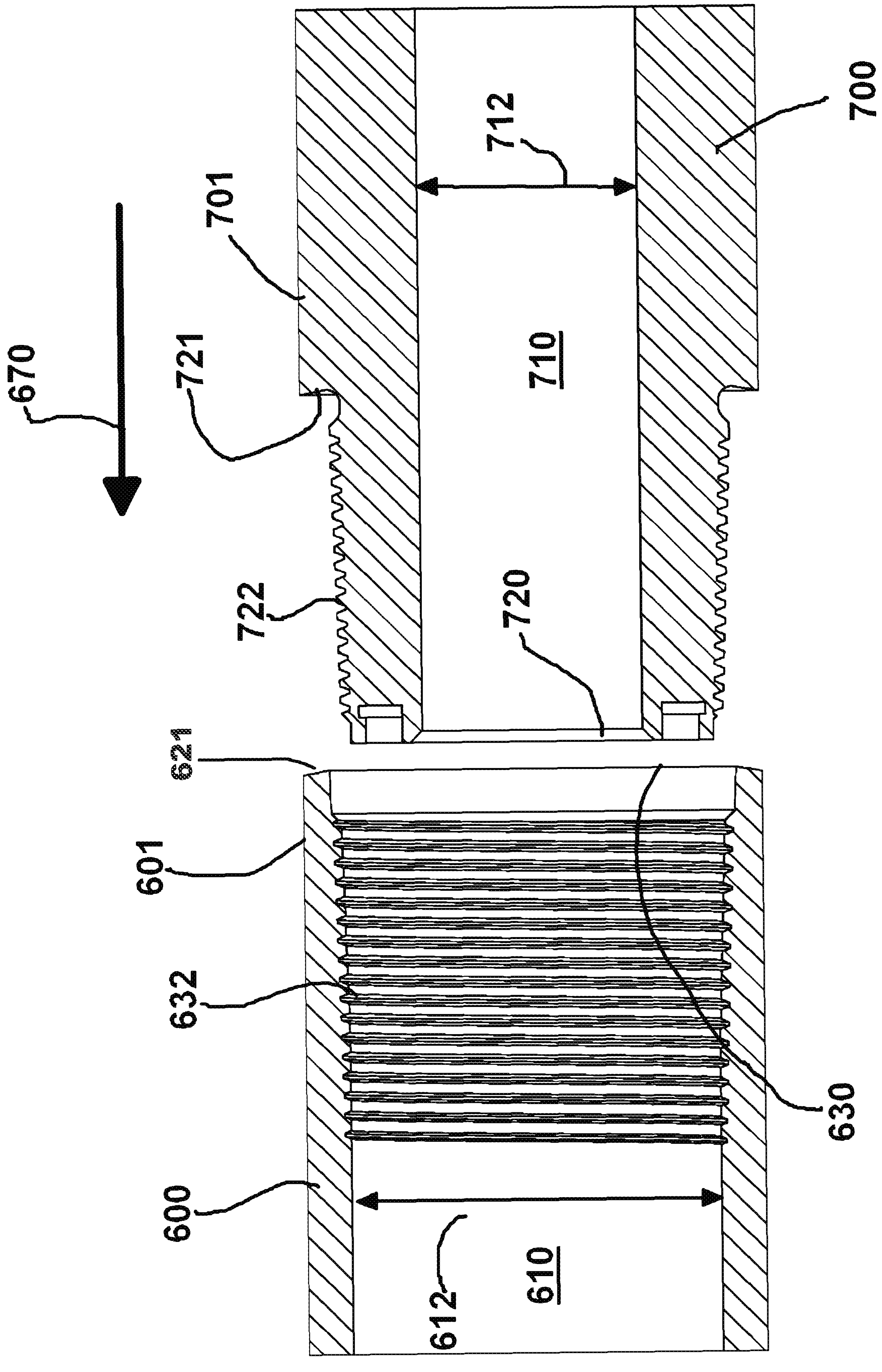


FIG. 35

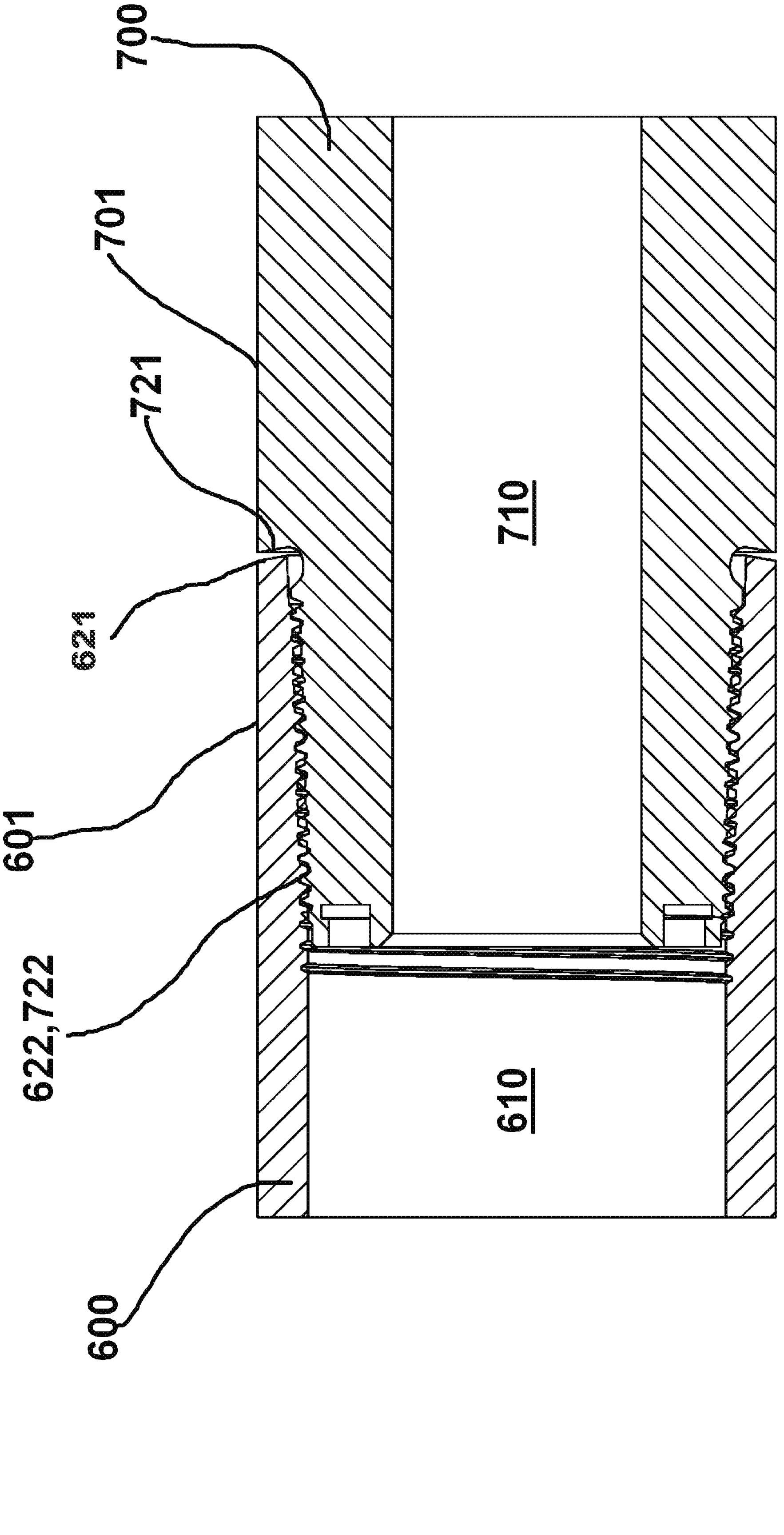


FIG. 36

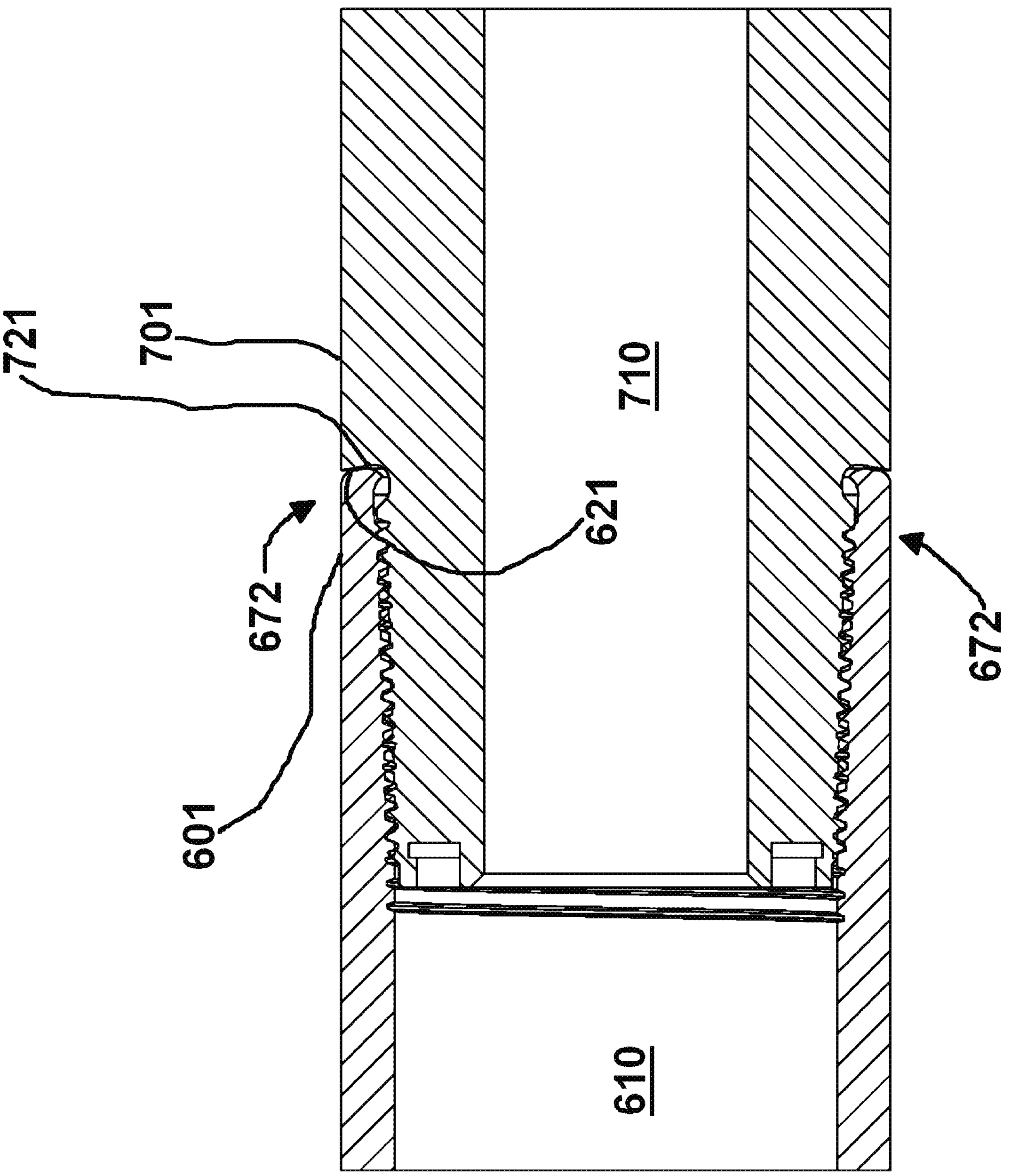
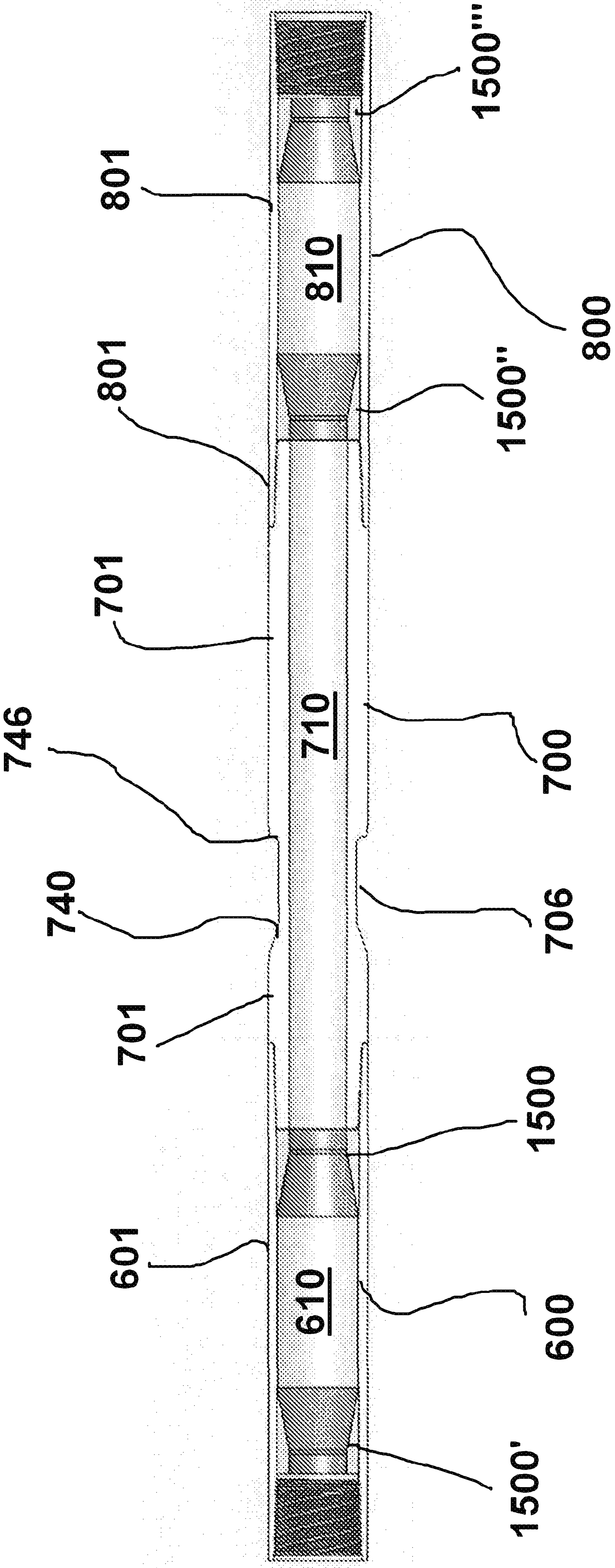


FIG. 37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1500''
701
710
700
746
740
706
701
1500
601
610
600
1500'

FIG. 38

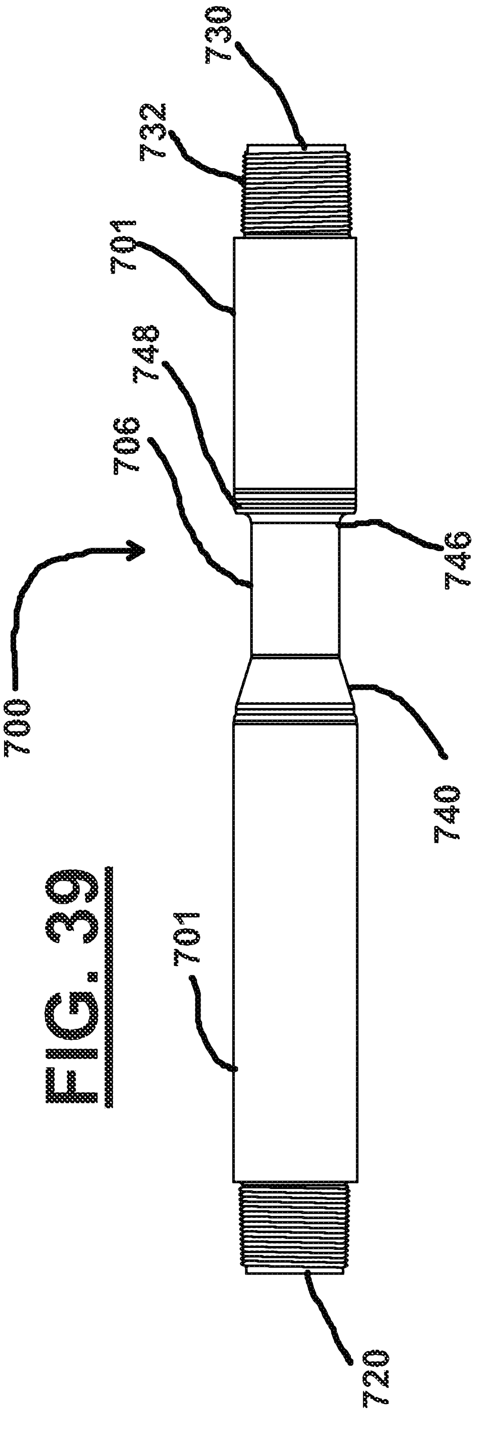


FIG. 39

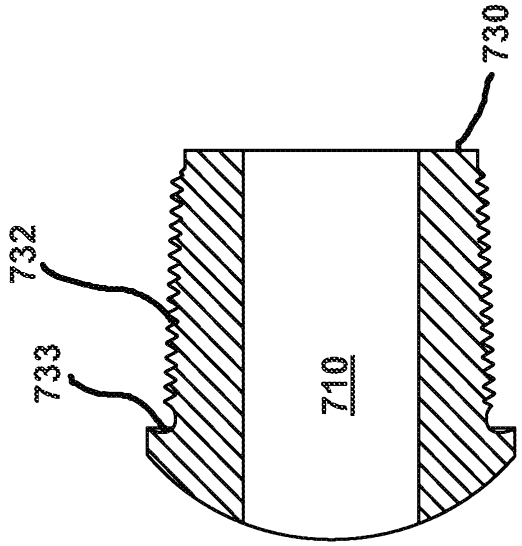


FIG. 42

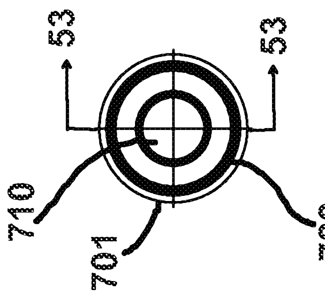


FIG. 40

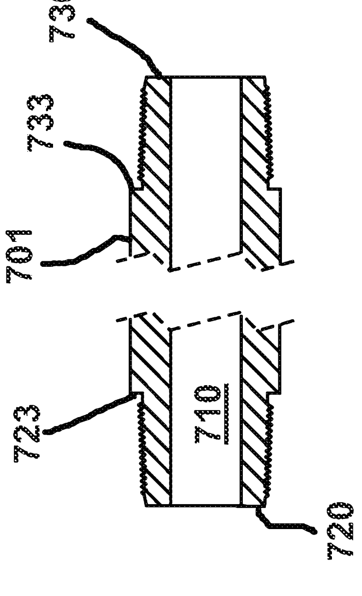


FIG. 41

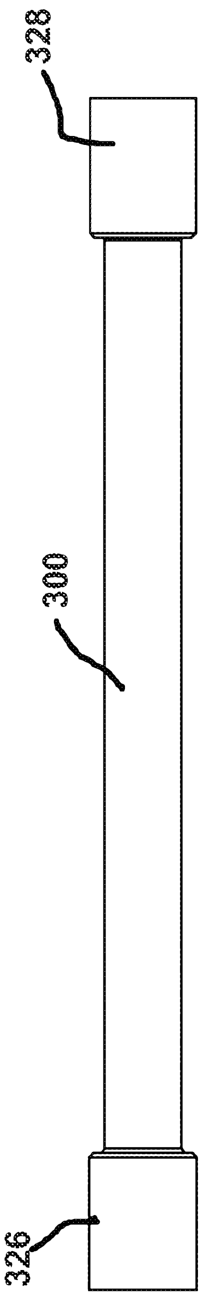


FIG. 43

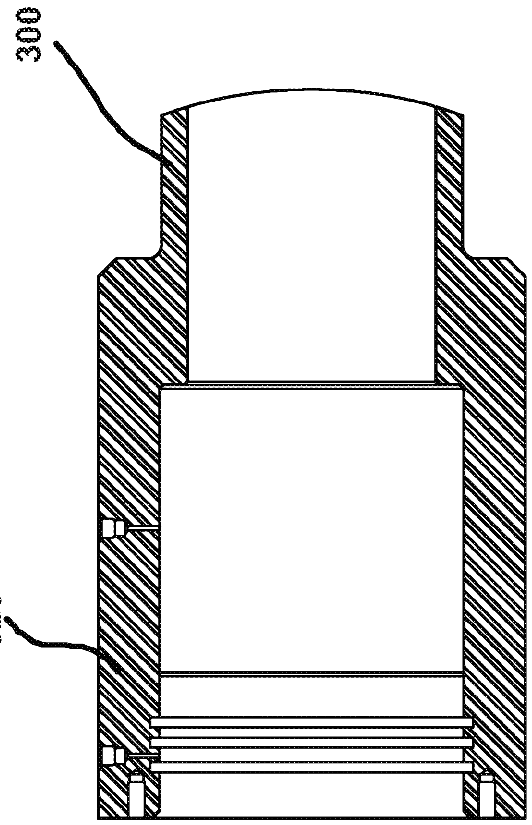


FIG. 45

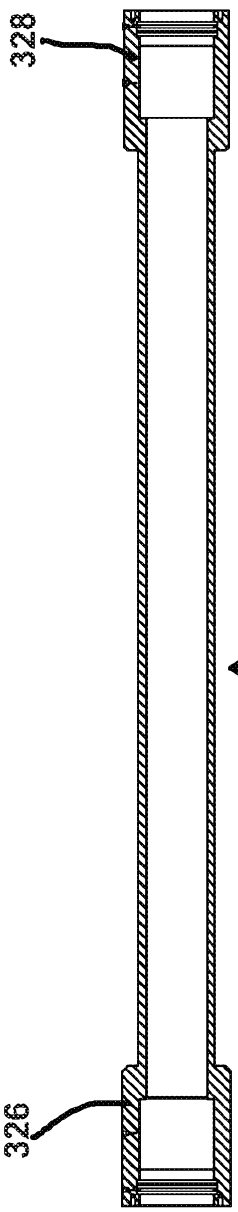


FIG. 44

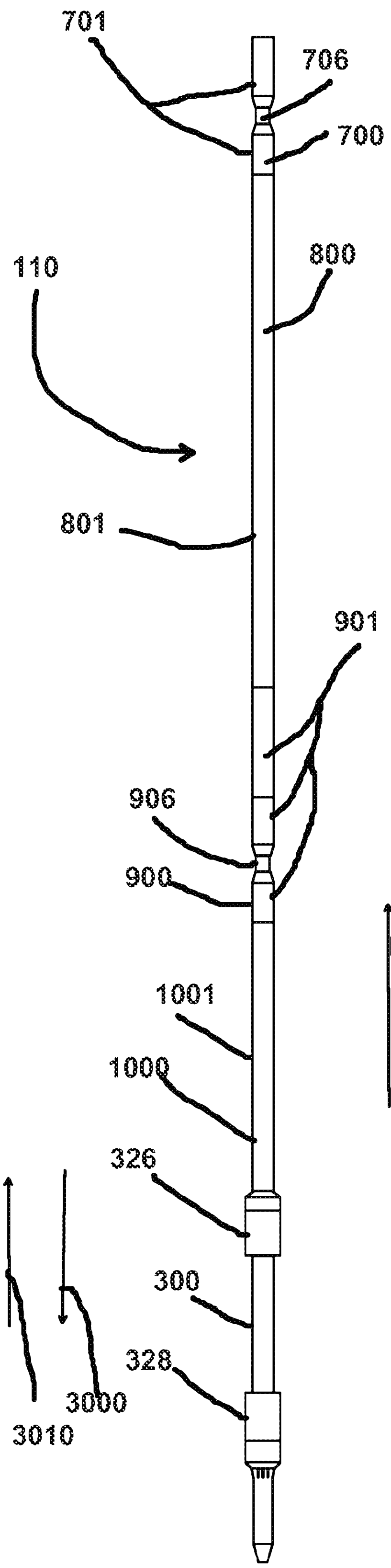


FIG. 46

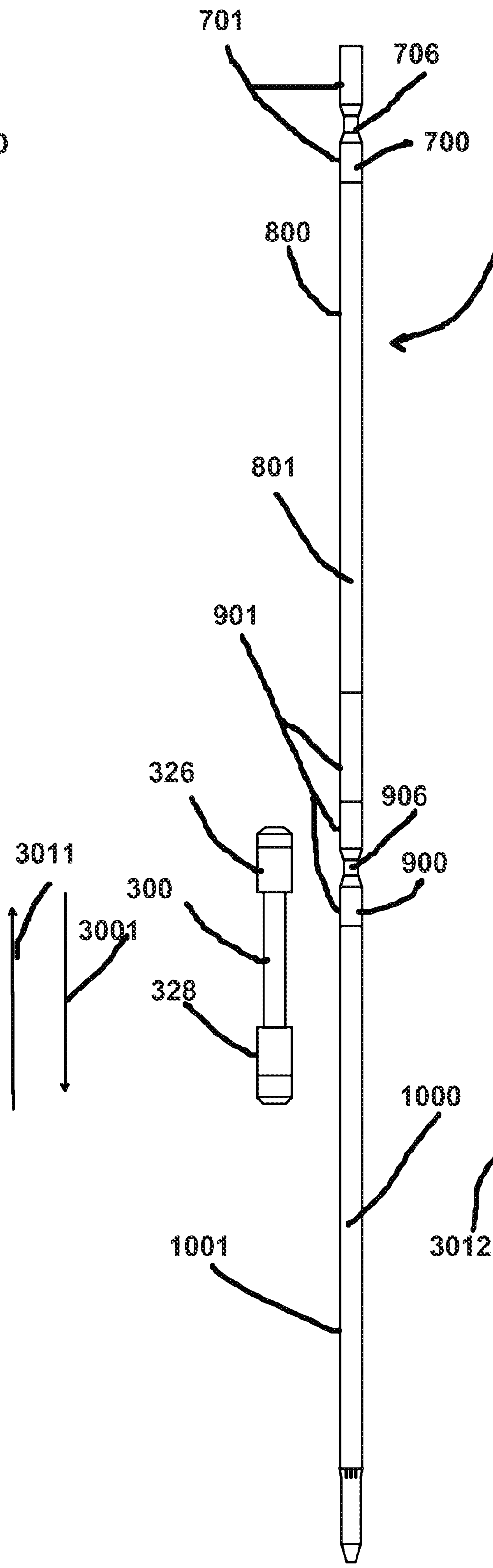


FIG. 47

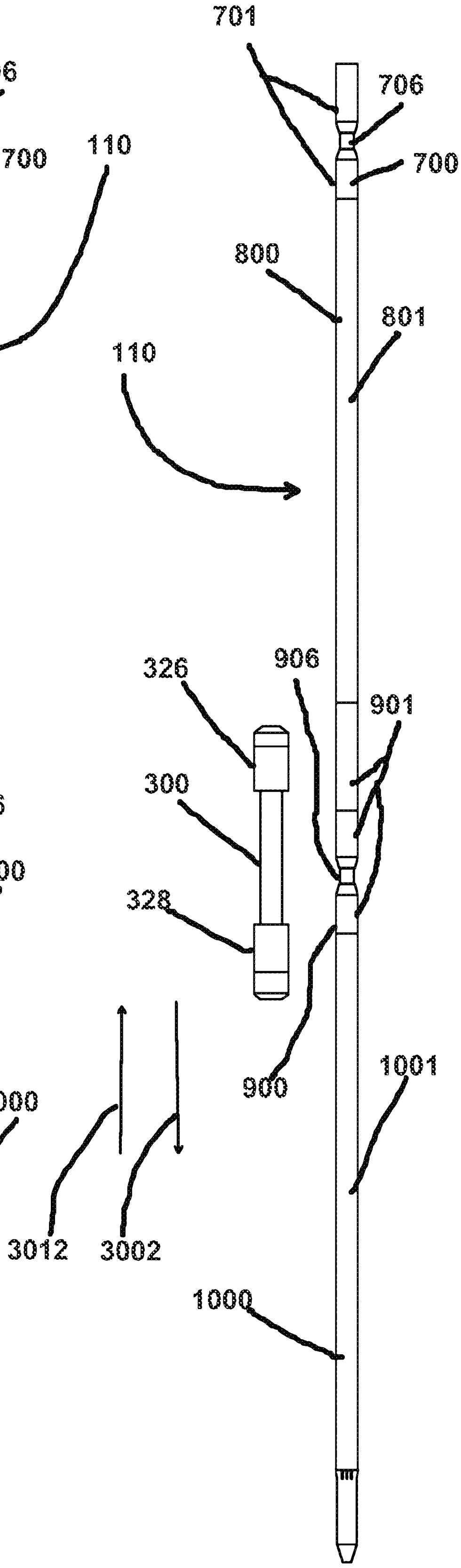


FIG. 48

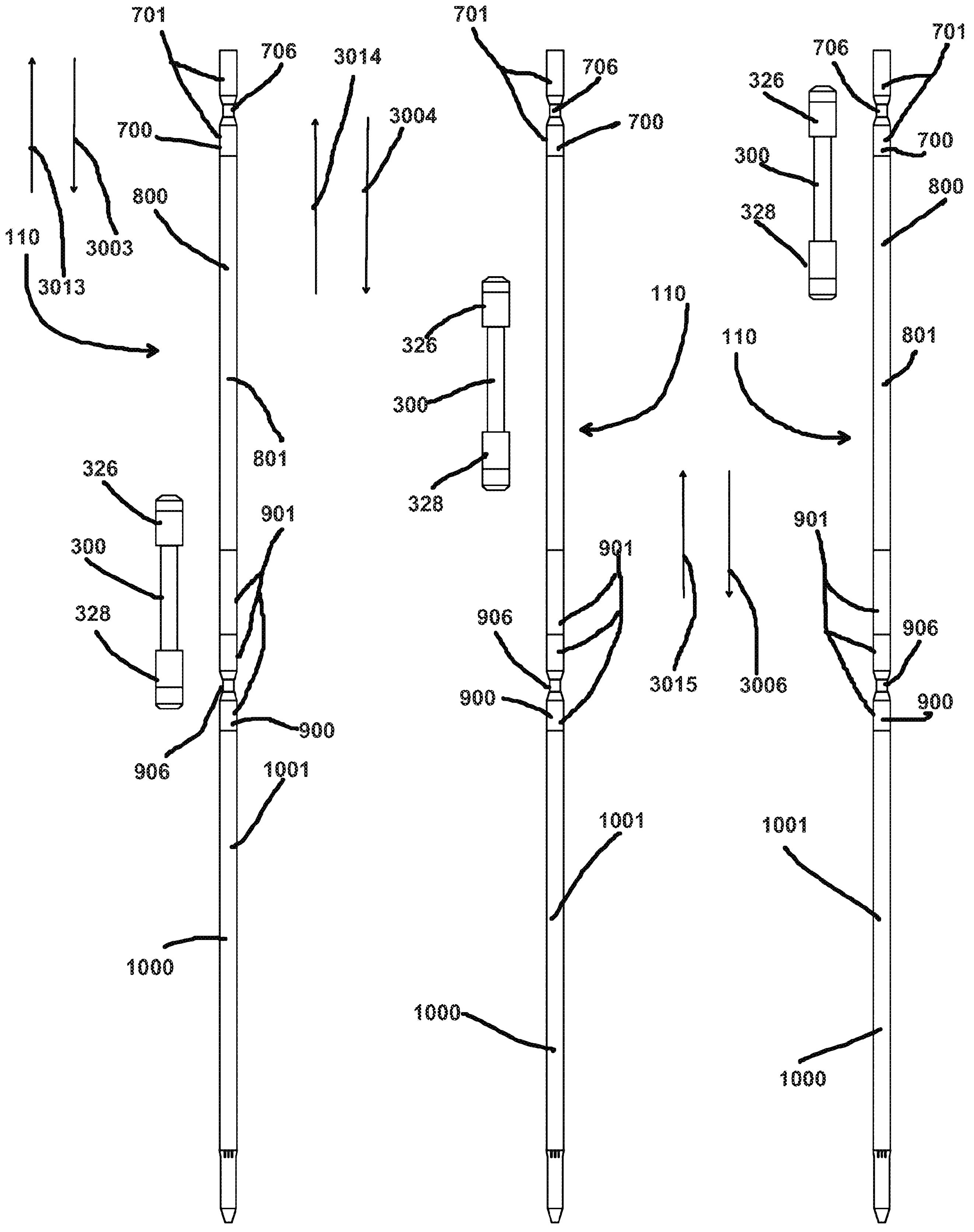


FIG. 49 FIG. 50 FIG. 51

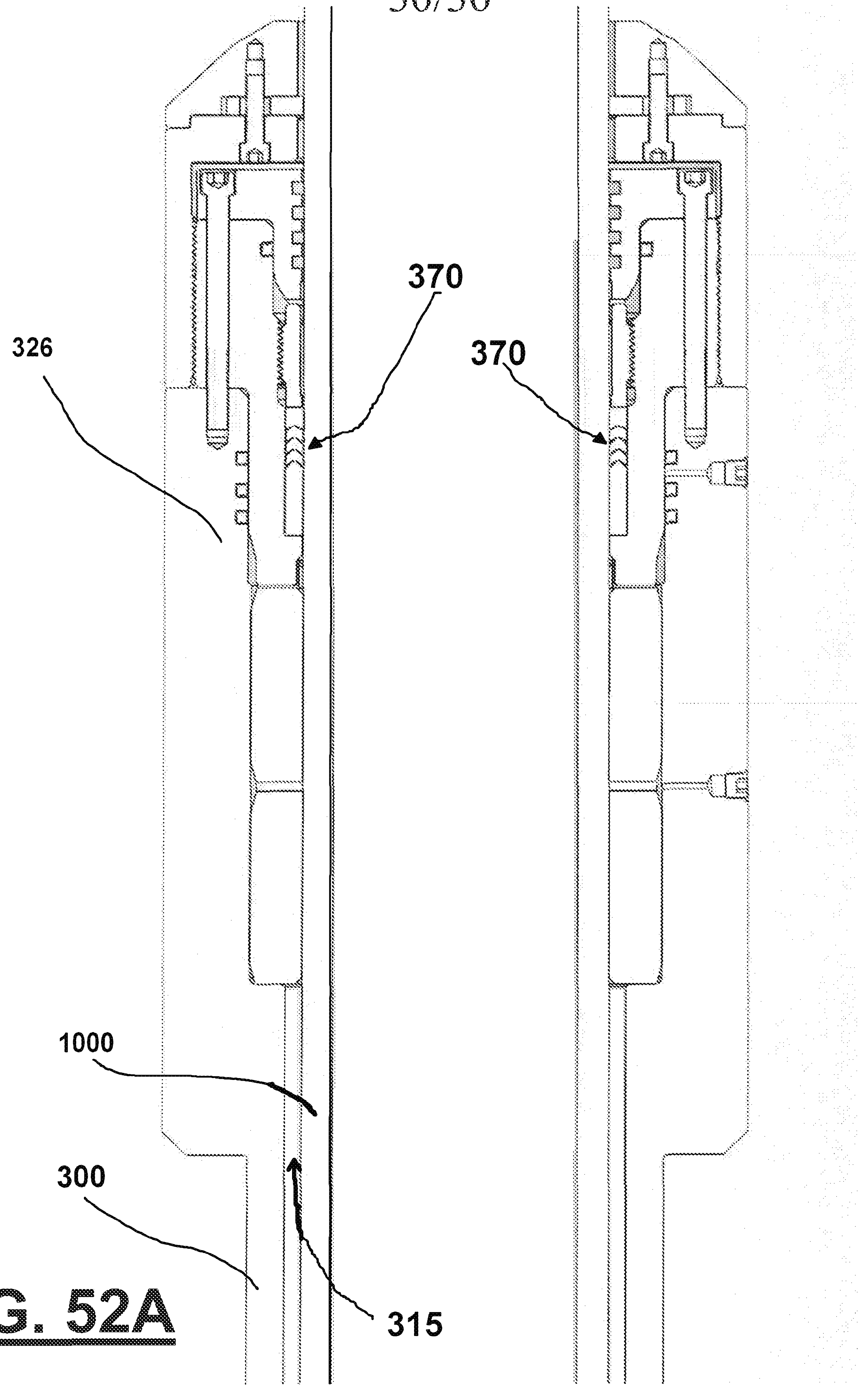


FIG. 52A

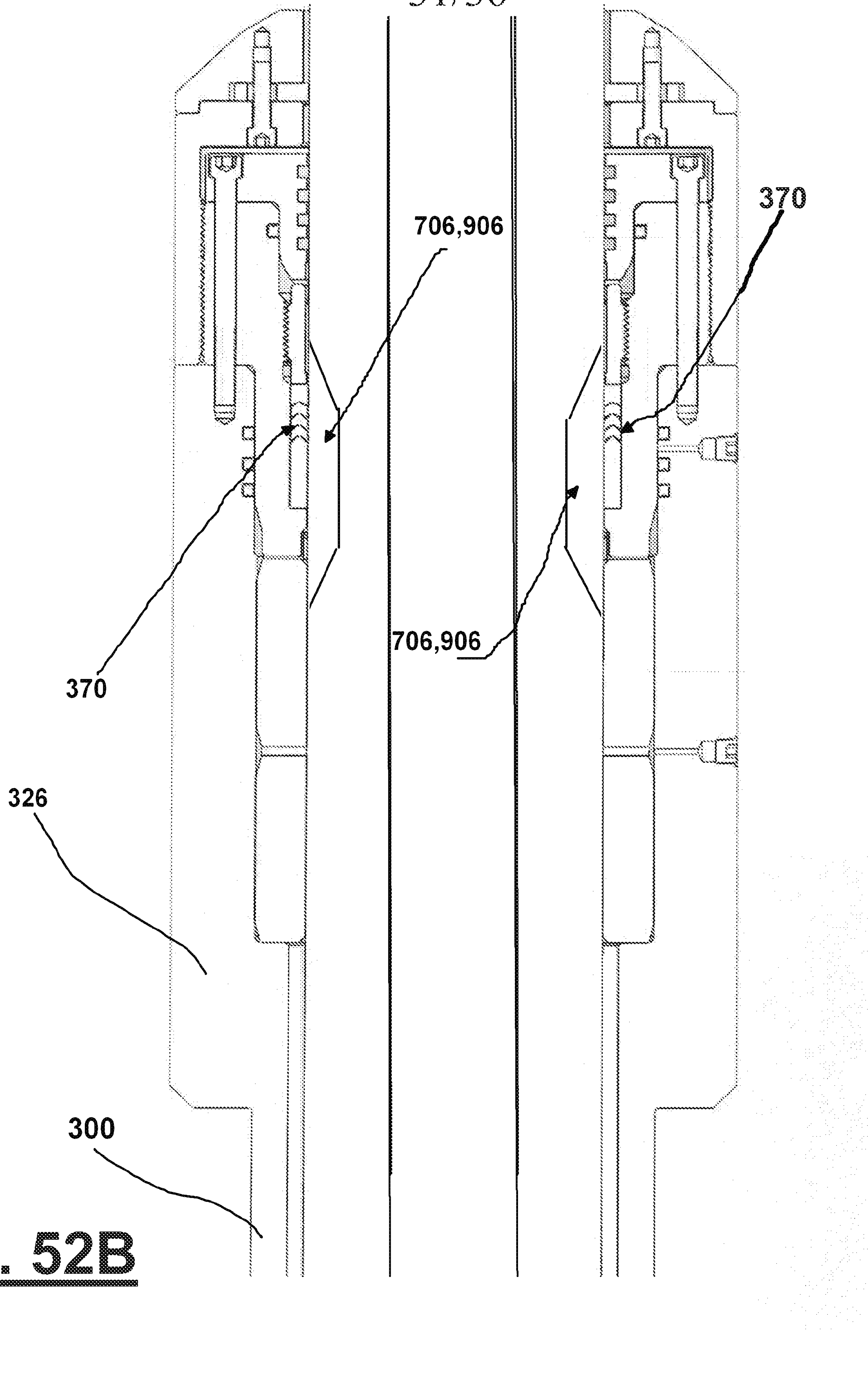


FIG. 52B

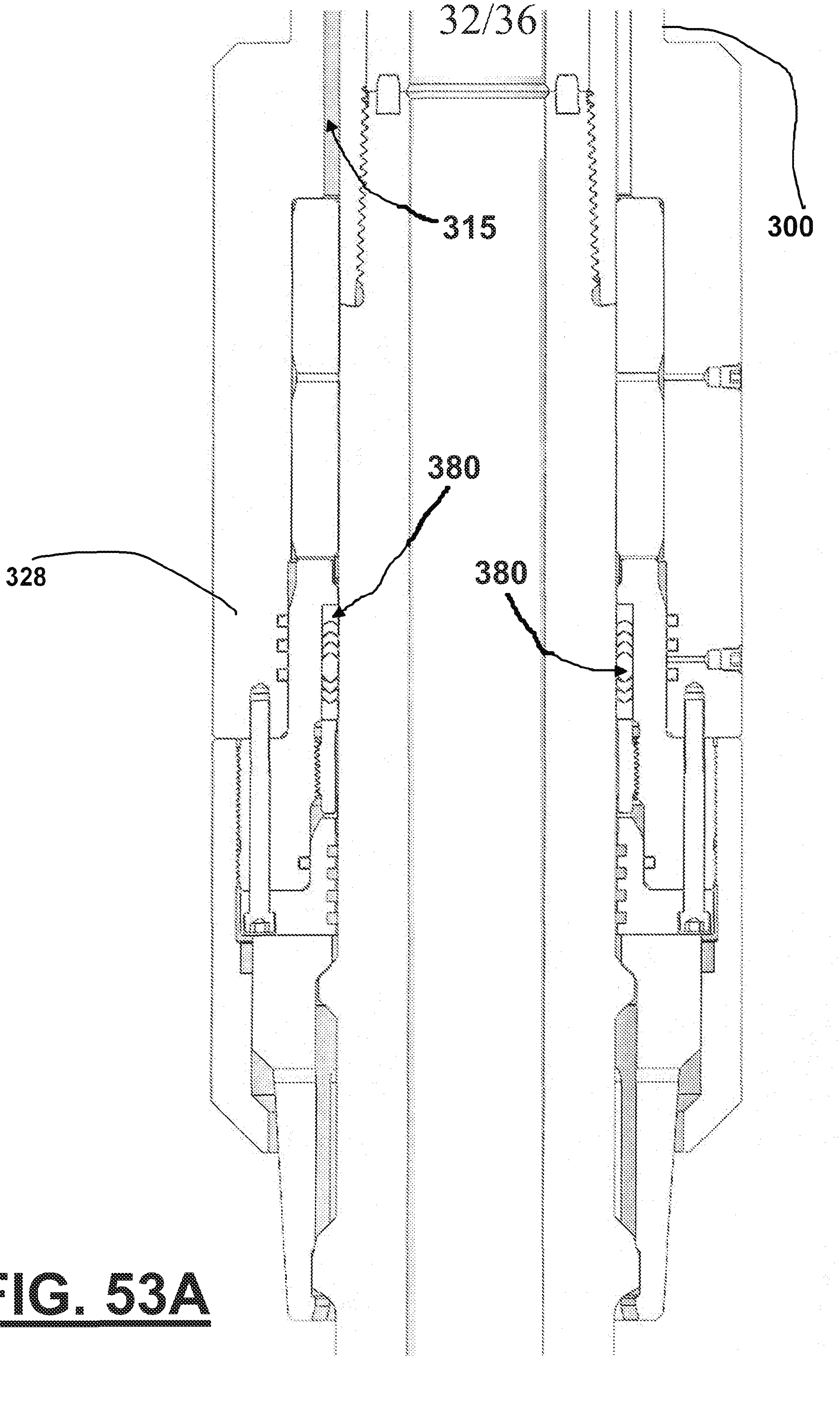


FIG. 53A

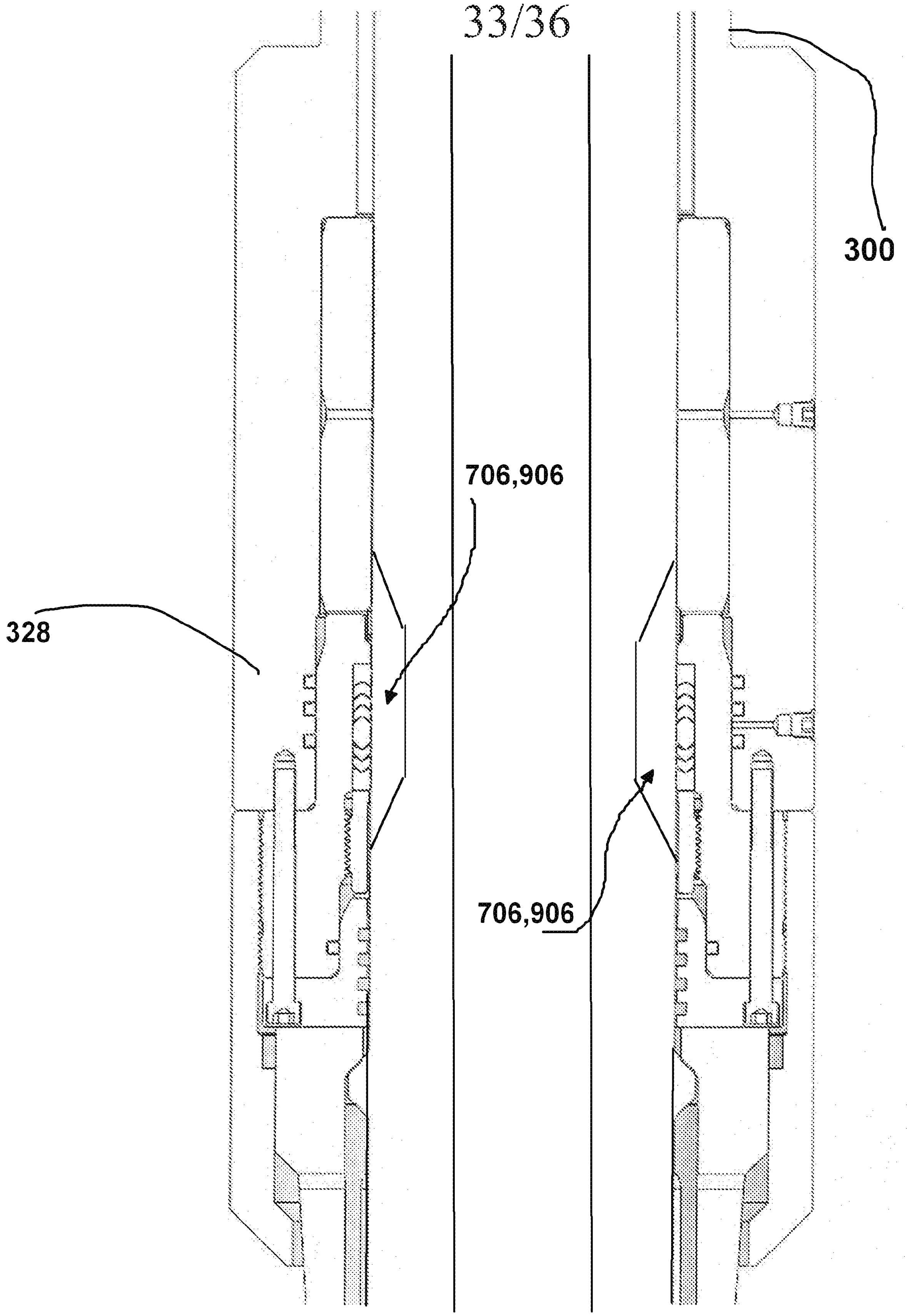


FIG. 53B

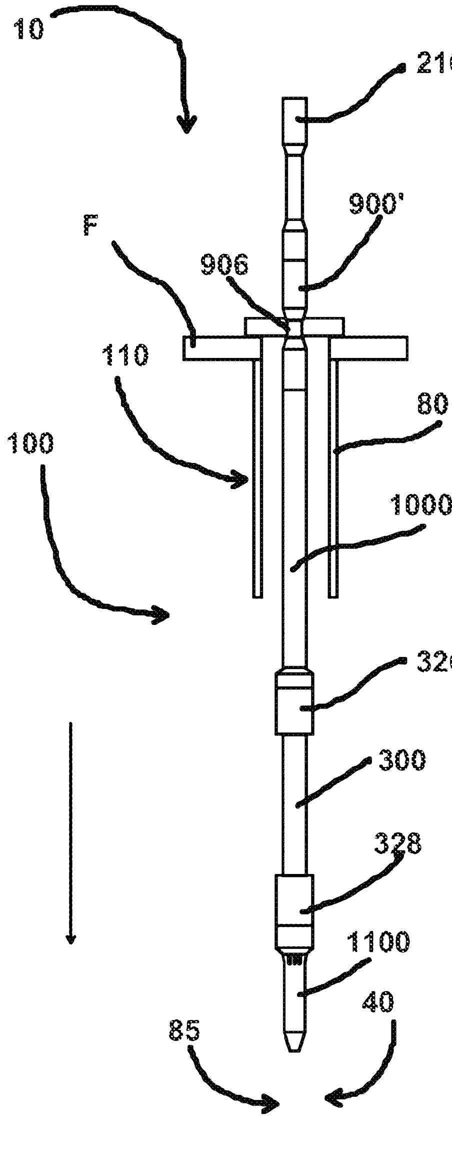


FIG. 54

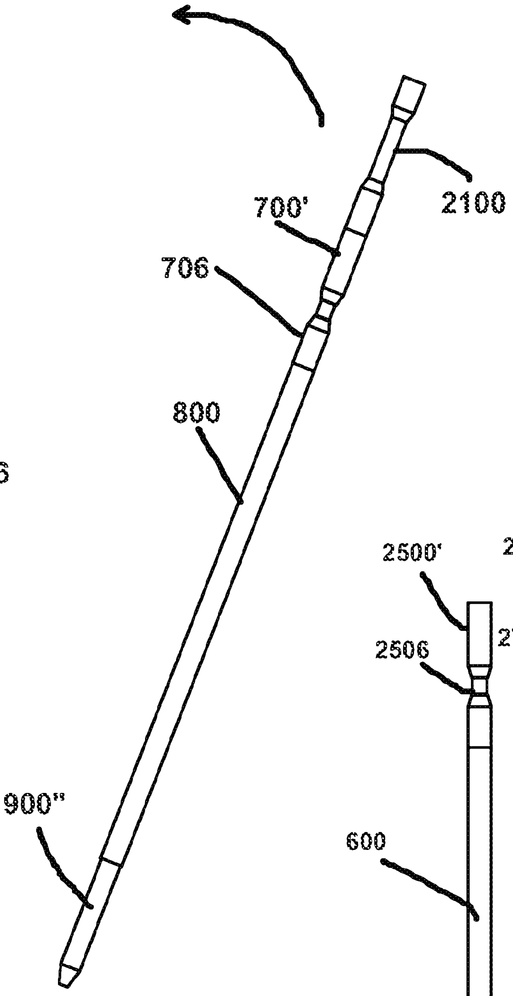


FIG. 55

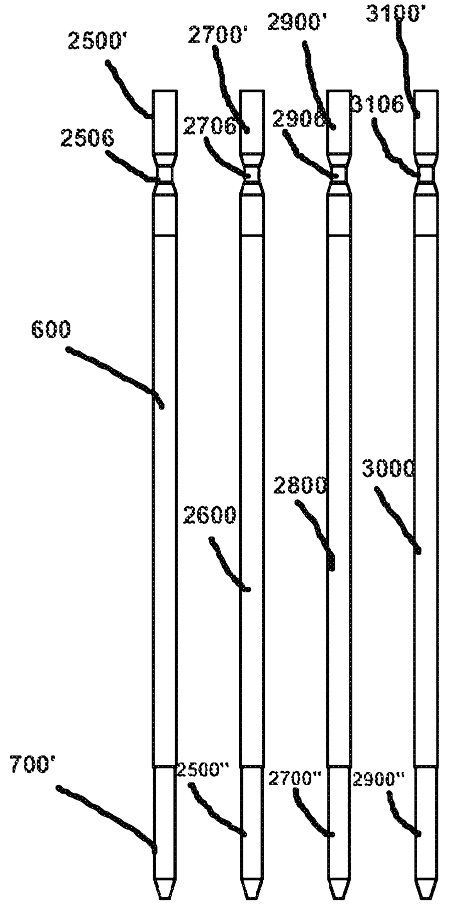


FIG. 56

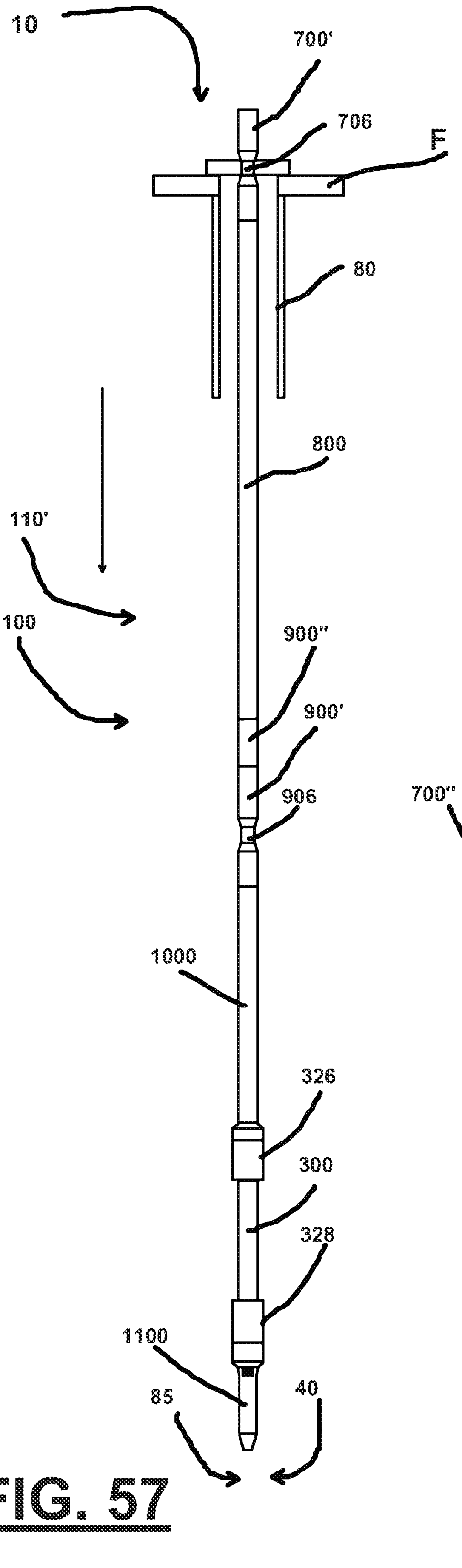


FIG. 57

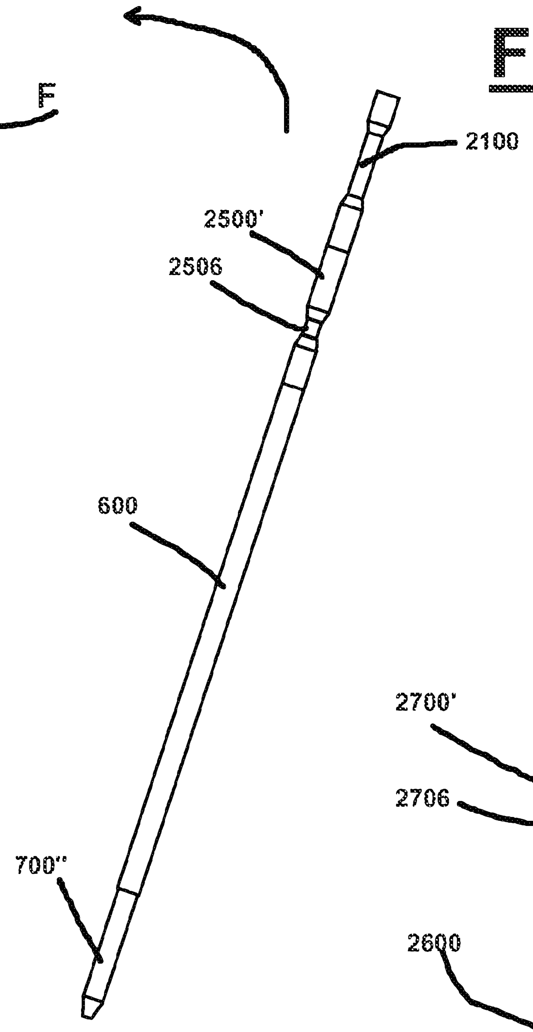


FIG. 58

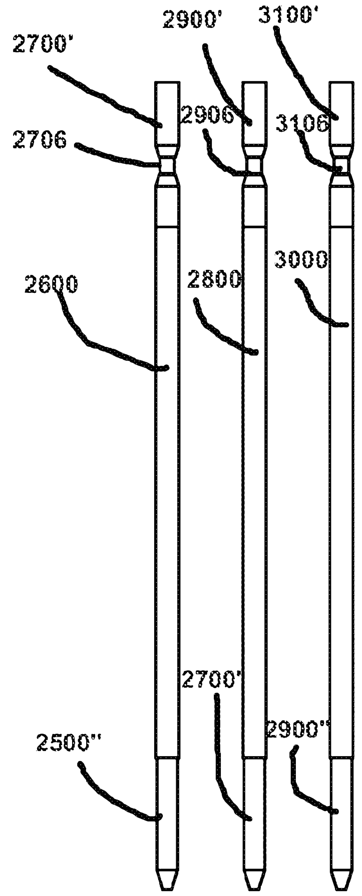


FIG. 59

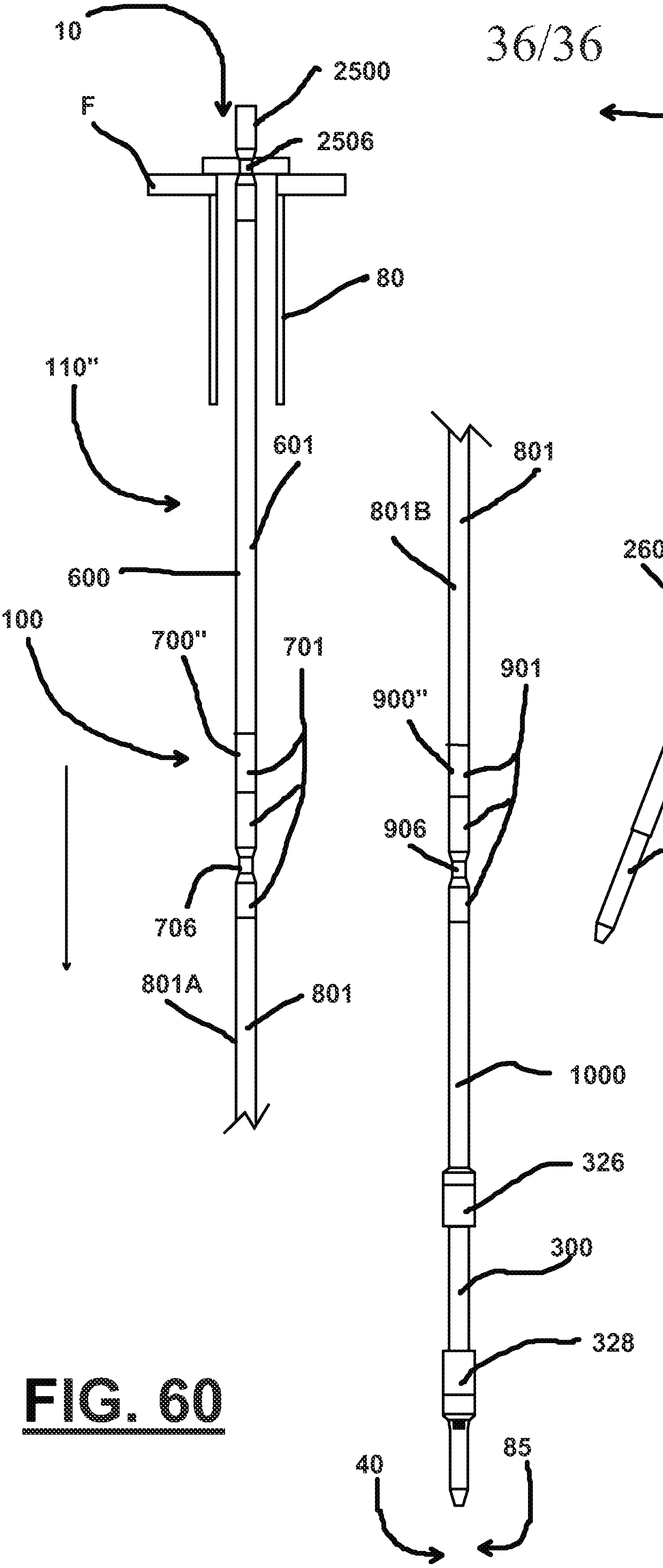
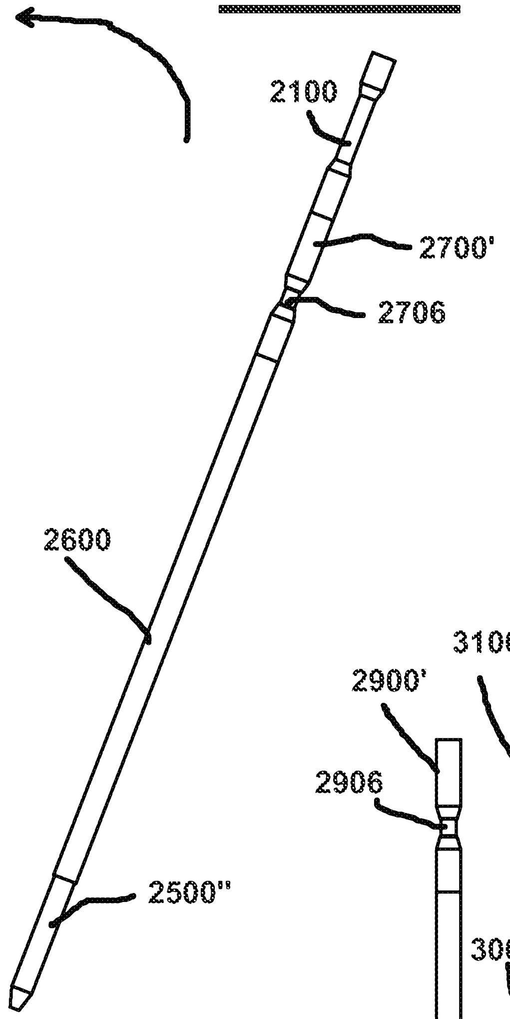


FIG. 60

FIG. 61



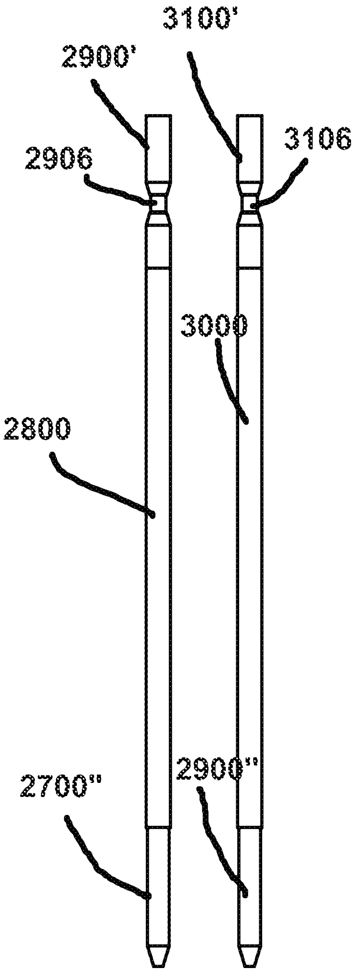


FIG. 62