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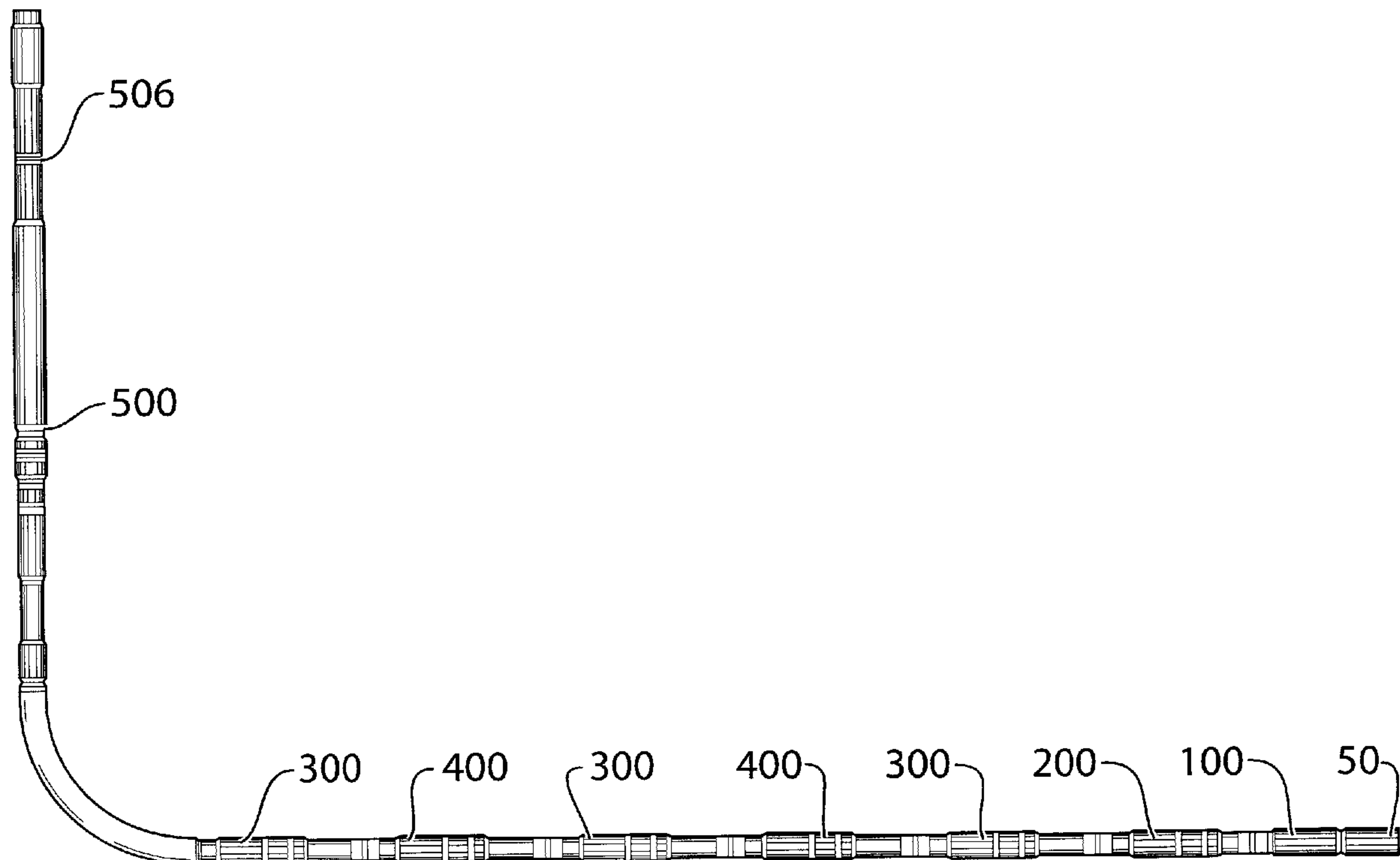
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(54) **Titre : ISOLATION DE PUITS MULTIETAGE ET FRACTURATION**

(54) **Title: MULTI-STAGE WELL ISOLATION AND FRACTURING**



(57) **Abrégé/Abstract:**

An activation tool is provided for use in a well isolation and stimulation string, The activation tool has a stationary seat for receiving a ball deployed down the string, a stationary inner body, a stationary outer body and a moving sleeve positioned between the stationary inner and stationary outer bodies and movable from an open position to a closed position by force of the ball against the seat. A first stage frac valve tool is also provided having a stationary outer body and an internal piston movable between an closed and an open position. A singular tool is further provided having a float shoe, an activation tool and integrally built with the float shoe and a first stage frac integrally built with the activation tool. A cased hole packer is further provided having an integral setting tool.

Abstract

An activation tool is provided for use in a well isolation and stimulation string, The activation tool has a stationary seat for receiving a ball deployed down the string, a stationary inner body, a stationary outer body and a moving sleeve positioned between the stationary inner and stationary outer bodies and movable from an open position to a closed position by force of the ball against the seat. A first stage frac valve tool is also provided having a stationary outer body and an internal piston movable between an closed and an open position. A singular tool is further provided having a float shoe, an activation tool and integrally built with the float shoe and a first stage frac integrally built with the activation tool. A cased hole packer is further provided having an integral setting tool.

Multi-Stage Well Isolation and Fracturing

Field of Invention

The present invention relates to devices for multi-stage, horizontal well isolation and fracturing.

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Background of the Invention

An important challenge faced in oil and gas well production is producing hydrocarbons that are locked into formations and not readily flowing. In such cases, treatment or stimulation of the formation is necessary to fracture the formation and provide passage of hydrocarbons to the wellbore, from which it can be brought to the surface and produced.

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Fracturing of formations via horizontal wellbores traditionally involves pumping a stimulant fluid through either a cased or open hole section of the wellbore and into the formation to fracture the formation and produce hydrocarbons therefrom.

In many cases, multiple sections of the formation are desirably fractured either simultaneously or in stages. Tubular strings for the fracturing of multiple stages of a formation typically include one or more fracturing tools separated by one or more packers.

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In some circumstances frac systems are deployed in cased wellbores, in which case perforations are provided in the cemented in system to allow stimulation fluids to travel through the fracturing tool and the perforated cemented casing to stimulate the formation beyond. In other cases, fracturing is conducted in uncased, open holes.

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In the case of multistage fracturing, multiple frac valve tools are used in a sequential order to frac sections of the formation, typically starting at a toe end of the wellbore and moving progressively towards a heel end of the wellbore.

Many configurations have been developed in the field to frac multiple stages of a formation. However, a need still exists for a fracturing system that will ensure stimulation of the formation from a toe end to a heel end of the wellbore, while being simple in construction, small in size and effective at fracturing formations in multiple stages

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Summary of the Invention

An activation tool is provided for use in a well isolation and stimulation string, said activation tool comprising a stationary seat for receiving a ball deployed down the string, a stationary inner body, a stationary outer body and a moving sleeve positioned between the stationary inner and stationary outer bodies and movable from an open position to a closed position by force of the ball against the seat.

A first stage frac valve tool is also provided for use in a well stimulation string, said first stage frac valve tool comprising a stationary outer body and an internal piston movable between an closed and an open position.

A singular tool is further provided comprising a float shoe, an activation tool comprising a stationary seat for receiving a ball deployed down the string, a stationary inner body, a stationary outer body and a moving sleeve positioned between the stationary inner, stationary outer bodies and movable from an open position to a closed position by force of the ball against the seat and integrally built with the float shoe and a first stage frac valve comprising a stationary outer body and an internal piston movable between an closed and an open position and integrally built with the activation tool.

A cased hole packer is further provided comprising an integral setting tool.

Brief Description of Drawings

Figure 1 is a schematic diagram of a horizontal well fitted with the tools of the present invention;

Figure 2 is a cross-sectional view of one example of the activation tool of the present invention, in various stages of use;

Figure 3 is a cross sectional view of one example of the first stage frac valve tool of the present invention, in various stages of use;

Figure 4 is a cross sectional view of one example of the cased hole packer of the present invention,

Figure 5 is a cross sectional view of the cased hole packer of the present invention, showing a first means of deployment;

Figure 6 is a cross sectional view of the cased hole packer of the present invention, showing a collet type latch seal assembly;

5 Figure 7 is a cross-sectional view of a cased hole packer that may be deployed on the casing string;

Figure 8 is a cross-sectional view of one example of a cased hole anchor of the present invention; and

Figure 9 is a schematic diagram of dual horizontal liners drilled in one well.

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Detailed Description of Preferred Embodiments

A series of tools is provided that improve on existing horizontal isolating and fracing tools, by providing increased safety during installation, reduced rig time and greater dependability of deploying the tools to the end of the horizontal section of the wellbore.

15 By combining both a slim outside diameter and short length, the present tools eliminate the need for handling pup joints, thereby reducing the rigidity of the liner. These features permit the more flexible, reduced outside diameter tool string to be deployed into the wellbore with greater ease.

20 The present invention consists of a series of tools strategically located along a liner and deployed into the open hole section of the wellbore. The tools provide a means of isolating various stages of the horizontal wellbore. After isolating various stages, stimulation fluid can be pumped from surface and through valve tools that are opened sequentially to thereby multi-stage frac the formation.

25 With reference to Figure 1, in a preferred method of deployment, the present system of tools comprises a cased hole packer 500 that anchors the liner and forms a seal between the casing string and the open hole. A float shoe or guide 50 is run at the toe of the liner. An activation tool 100 is placed a pre-determined distance from the guide shoe 50. Next is a first stage frac valve tool 200, and then an series comprising an open hole packer 300 alternated with one or more subsequent stage frac valve tools 400. It would be well understood by a

person of skill in the art that Figure 1 merely represents one example of a tubular fracing string of tools and that additions, omissions and alterations to the illustrated string and its components can be made without departing from the scope of the present invention.

The float shoe 50 is preferably provided with an open end having a flap covering. The open end allows the liner pressure to be at least somewhat equalized with the formation pressure while the flap prevents ingress of formation fluids into the liner.

It would be understood by a person of skill in the art that any float shoe or similar device known in the art could be used with the tools of the present invention without departing from the scope thereof.

The activation tool 100, as seen in Figure 2 comprises an opening 102. The one piece construction of the outer body 120 of the activation tool allows torque to be applied from the upper liner section, through the tool and into the liner to make up the liner string. The activation tool 100 can be lifted by hand and hand threaded onto the liner, which is typically gripped at the rig floor, and then a section of upper liner, typically gripped in an elevator or similar device, can be lowered onto the tool.

The opening 102 is open during deployment such that fluid can be circulated through the opening 102 when the liner is being run into the well, as seen in Figure 2a. At a predetermined depth, a ball 104 is circulated down to the activation tool 100, as seen in Figure 2b, and prevents circulation through opening 102 and re-directs fluid into a chamber 106 formed between an activation tool inner body 118 and a sleeve 110. As seen in Figure 2, opening 102 extends through a portion of sleeve 110. The sleeve 110 comprises a first and a second diameter, D1 and D2 respectively. While D1 is exposed to wellbore fluids and experiences wellbore pressures, D2 is exposed to fluid pressure from within the liner. The product of the difference in these pressures and the difference in these diameters defines the force needed to displace sleeve 110 and move the activation tool 200 from an open (Figures 2a, 2b) to a closed position (Figure 2c).

Pressure from the liner fluid serves to shears screws 108 that have been holding the sleeve 110 in the open position. The sleeve 110 then shifts a stroke length of 124 and the opening 102 closes, blocking flow through the opening 102. With fluid flow blocked in the liner,

pressure increases to thereby trigger activation and setting of the open hole packers 300 and the cased hole packer 500.

A number of seals 116 between the sleeve 110 and the activation tool inner body 118 guide this movement from open to closed.

5 Preferably, a collet 112 located on and integral to the sleeve 110 travels stroke length 122 and catches against an end of the activation tool inner body 118 when the sleeve 110 is in the closed position and prevents the sleeve 110 from shifting back to its original, open position. In its locked and set position, the activation tool 100 further advantageously serves as a redundant safety device to the float shoe 50, ensuring that wellbore fluids do not enter the
10 liner prior to fracing.

Advantageously, the opening 102 in the activation tool has been designed with minimum moving parts. The ball 104 and its corresponding seat 114 are entirely comprised of non-moving components, thereby eliminating the risk of creating a hydraulic lock, or locking of parts due to the presence of an incompressible fluid that has nowhere to be displaced to, below
15 the opening 102. Instead, the internal sleeve 110 shifts to close the opening 102 and is locked by means of the collet 112, so that in the event that the ball 104 undesirably rolls off of the valve seat 114, the opening 102 remains in the closed position. Since stroke length 124 needed to shift sleeve 110 is equal to stroke length 122 needed to shift the collet 112, only one stroke length is required to close the opening 112 and lock internal sleeve 110.

20 The next tool in the present invention is the first stage frac valve tool 200, depicted in Figures 3a and 3b. This is the frac valve through which the first stage of the stimulation is pumped to the toe of the wellbore. The present first stage frac valve tool 200 can be lifted by hand and hand threaded onto the liner, which is typically gripped at the rig floor, and then a section of upper liner, typically gripped in an elevator or similar device, can be lowered onto
25 the tool.

Since the closing of the activation tool 100 prevents circulation of fluid, the first stage frac valve tool 200 relies solely on applied pressure to open. The opening pressure of the first stage frac valve tool 200 must be greater than the pack off pressure required to set the open hole packer 300 and cased hole packer 500. Increasing liner fluid pressure acts on surface D1

to apply pressure on piston 204. The opening pressure of the first stage frac valve tool 200 is preferably controlled by the number of shear screws 202 installed into the piston 204, although other known means of controlling opening pressure would also be understood by a person of

skill in the art and encompassed by the present invention. At a pre-determined shear force, the shear screws 202 shear allowing the piston 204 to be shifted to the open position, as seen in Figure 3b.

A pair of seals 206 between the piston 204 and the frac valve outer body 222 guide movement of the piston 204 from closed to open. In the open position, ports 210 are opened to allow fluid to flow from inside the liner into the formation to thereby stimulate the adjacent formation.

A snap ring 208 preferably locks the piston 204 in the open position, although other known biasing means may also be used and would be well known to a person skilled in the art. Advantageously, the moving parts of the first stage frac valve tool 200 are all internal, meaning they do not have to overcome friction against the wellbore to shift from closed to open, allowing better control over the system.

A further advantage of the present first stage frac valve tool 200 is its ability to transmit torque. During installation torque can be transmitted through the first stage frac valve tool 200 from a joint above into the liner below in order to make up the threads. The internal body connection of the first stage frac valve tool 200 has been designed to handle torque greater than the make-up torque of the liner connections. The ability to transmit torque, combined with its short size, eliminate the need for handling joints that would need to be torqued on both ends of the first stage frac valve tool 200.

Preferably, the geometry of the fracture ports 210 provides easy identification for the first stage frac valve tool 200, thereby reducing the potential for incorrect placement in the liner string. The unique geometry of the fracture ports 210 differentiates the appearance of the first stage frac valve tool 200 from other similar looking valves installed on the liner. Ports 210 may also preferably be sized to reduce or prevent ingress of wellbore debris into the liner.

In a further preferred embodiment of the present invention a singular tool (not shown) comprising a float shoe 50 /activation tool 100 /first stage frac valve tool 200 can be used to replace individual float shoe 50, activation tool 100 and first stage frac valve tool 200 with liner joints connecting them. Advantageously, the singular combination tool (not shown) requires less threaded connections, thereby reducing potential leak paths and decreases rig time since

only one threaded connection needs to be torqued on the rig floor. The singular combination tool (not shown) also ensures that the fracture ports 210 of the first stage frac tool 200 are as close to the toe of the well as possible.

When the first stage frac valve tool 200 opens, the formation is immediately exposed to
5 high pressure liner fluid. In an alternative embodiment, the first stage frac valve tool 200 may be configured such that a high fluid pressure is required to unlock the piston 204, then a second surge of low pressure serves to open the fracture ports 210. This embodiment of the first stage frac valve tool 100 can be used to protect sensitive formations from excessive pressures.

The next tools installed onto the liner are a series of one or more open hole packers 300
10 and a frac valve tools 400. The open hole packers 300 are preferably single element open hole packers 300.

The next element of the present invention is the cased hole packer 500, which is run at the top of the liner, and is illustrated in Figure 4. The cased hole packer 500 is a hydraulically set, preferably permanent packer with a tie back receptacle 502 and is used to anchor the liner
15 into the casing string and provide a seal between the top of the liner and the casing string.

Many prior art cased hole packers require a setting tool that is separate to the cased hole packer and used to set the packer against the casing string. To accommodate such cased hold packer and setting tool, the tool must be run on drill pipe, which is narrower than a typical frac string and therefore provides sufficient room between the drill pipe outer diameter (OD)
20 and the casing string to accommodate the setting tool. Once deployed, the setting tool and drill pipe are then typically pulled out and a frac string is deployed to proceed with the fracing operating.

The present cased hole packer 500 advantageously incorporates an integral setting tool in the form of slips 504 to activate the cased hole packer 500. The slips 504 do not extend
25 beyond the OD of the cased hole packer 500 and require no additional space. Thus the present cased hole packer 500 and other present tools can be run on a frac string, without the need to run a drill string and then change out to a frac string, saving time during operation. It would be well understood by a person of skill in the art that the present cased hole packer 500 can also

be deployed on drill string and any number of means can be used to accommodate this smaller diameter pipe.

The opposing slips 504 serve to anchor the cased hole packer 500 to the casing string in both tension and compression due to wickers formed on an outer surface thereof that act to engage the casing string inside diameter when the cased hole packer 500 is set.

After the liner has been deployed, the cased hole packer 500 is set by pressure buildup in the liner due to activation of the activation tool 100. A setting piston 534 on the cased hole packer mandrel 530 comprises a first and a second diameter, D1 and D2 respectively. While D1 is exposed to wellbore fluids and experiences wellbore pressures, D2 is exposed to fluid pressure from within the liner. The product of the difference in these pressures and the difference in these diameters defines the force needed to displace setting piston 534 and move the cased hole packer 500 from an unset to a set position. A pair of seals 516 between the setting piston 534 and the mandrel body 530 guide this movement from unset to set.

Upon movement of the setting piston 534 triggers movement of the opposing slips 504 against a pair of upper and lower cones 520, that in turn presses against the packing element 522 causing packing element 522 to protrude into the wellbore until it comes in to sealing contact with the casing string inside diameter (ID). The cased hole packer 500 is held in place and prevented from unsetting by a ratchet ring 528.

The packing element 522 is comprised of a solid band of flexible material having a thickness such that an outer surface of the packing element 522 in its unset position sits flush with an outer surface of the upper and lower cones 520. Suitable materials for the packing element include any number of fluorocarbons and per-flouorocarbons such as AFLASTM, HNBR, and VitonTM, although it would be understood by a person of skill in the art that any flexible material showing resiliency and sufficient strength to maintain packing against wellbore fluid pressure would be suitable for the purposes of the present invention.

In a preferred embodiment, the packing element 522 is thinner at its axial midpoint than everywhere else. More preferably, the packing element 522 is formed with a circumferential groove 540 of predetermined width and depth around its inner surface at the axial midpoint, such groove 540 creating a thinner middle portion of the packing element 522. The groove 540

ensures that the packing element 522 protrudes from its axial midpoint, thereby providing even contact with the wellbore and a positive seal. In a further preferred embodiment, a packing element ring 542 is provided on the mandrel 530 onto which the packing element groove 540 sits. The packing element ring 542 fills in the void of the groove 540 and ensures that the
5 midpoint of the packing element 522 protrudes outwards upon actuation, and does not fold inwardly into itself.

One or more anti-extrusion expandable rings 524 hold the packing element 522 in place and press against the packing element 522 in actuation.

10 More preferably, the anti-extrusion rings 524 are positioned between backup rings 544 and the upper and lower cones 520 respectively.

The backup rings 544 are preferably shaped to allow an end of the upper and lower cones 520 to travel along and wedge into one contour of the backup ring 544 while allowing the anti-extrusion ring 524 to travel along and wedge between the upper and lower cones 520 and another contour of the backup ring 544 at each end of the packing element 522. Such wedging
15 prevents the packing element 522 from extruding internally and prevents packing element creep during high differential pressures and helps centralize the cased hole packer 500 while setting.

The use of the present anti-extrusion rings 524 creates a barrier around the packing element 522 after the cased hole packer 500 is set. Without this barrier the packing element
20 522 would not be able to maintain a seal at high differential pressures inside the casing.

A ratchet ring 528 is located between the mandrel body 530 and the setting piston 534 that serves to prevent the piston 534 from backing off from a set position, thus ensure that the packing element 522 remains in a set position once set.

25 In the present cased hole packer 500 the ratchet ring 528 is preferably comprised of a split ring with an inner surface ratchet profile and an outer surface ratchet profile. Preferably the inner surface ratchet profile is finer than the outer surface ratchet profile.

The ratchet ring 528 is first assembled onto the mandrel 530 of the cased hole packer 500, at least a part of the outer surface of the mandrel 530 having a ratchet profile that mates with the inner surface ratchet profile of the ratchet ring 528. Preferably the ratchet ring 528 is

assembled over one or more spring pins 546 installed on the mandrel 530 to maintain the position and alignment of the ratchet ring 528. A locking body thread 532 formed on an inner surface of at least part of the setting piston 534 is then installed over the ratchet ring 528. Preferably, the locking body thread 532 mates with the outer surface ratchet profile of the
5 ratchet ring 528.

Orientation of the inner surface ratchet profiles of the ratchet ring 528 allow the setting piston 534 and ratchet ring 528 to travel from unset to set position along the mandrel body 530, while preventing the setting piston 534 and ratchet ring 528 from sliding back to an unset direction from a set position. Orientation of the outer surface ratchet profile of the ratchet ring
10 528 allows the setting piston 534 to slide over the outer surface of the ratchet ring 528 when it is being installed onto the ratchet ring 528. Once the locking body thread 532 and the outer surface ratchet profile of the ratchet ring 528 mate, these mating profiles lock the ratchet ring 528 to the setting piston 534 when the setting piston 534 moves from an unset to a set position.

15 The ratchet ring 528 and setting piston 534 have a larger ID than the mandrel body 530 OD, thereby being able to be installed on the mandrel 530 without having to split the locking body 532 from the setting piston 534.

The tie back receptacle 502, illustrated in more detail in Figure 5, acts as a sealing interface and latching mechanism between the liner and drill string, should a drill string be used
20 in deployment, and as a sealing interface and latching mechanism between the liner and frac string during stimulation.

In a preferred embodiment, the cased hole packer 500 may also comprise one or more grooves (not shown) machined circumferentially around the O.D. of the cased hole packer 500. The grooves can receive a clamp to permit shop pressure testing of the cased hole packer 500
25 to high pressures to verify correct assembly. The clamp prohibits the cased hole packer 500 from setting, while testing the integrity of the tool's internal seals.

The present cased hole packer can be deployed using three different deployment methods. In a first embodiment, the cased hole packer 500 can be attached to a jay type latch seal assembly 506, illustrated in Figure 5. The latch seal assembly 506 is used to connect and

seal the liner to the drill string, if a drill string is used, during deployment. The latch seal assembly 506 will have an upper thread 508 compatible with the thread on the drill string. It also has an anchoring mechanism 510 compatible with the tie back receptacle 502 that serves to anchor it to the packer. Seals 512 located on the latch seal assembly 506 engage matching seal bore located on the tie back receptacle 502 to prevent fluid leak between the tie back receptacle 502 and the latch seal assembly 506. In a situation where the latch seal assembly 506 used directly with the frac string, and where no drill string need first be deployed, an upper thread 508 is sized to be compatible with the threads on the frac string.

The jay type latch seal assembly 506 is preferably full bore with an ID matching the liner I.D., and no restrictions in the mandrel 514 of the latch seal assembly 506. Shear screws 518 installed prior to deployment ensure that the liner and cased hole packer 500 cannot disengage from the drill/frac string prematurely. The shear screws 518 are installed through the tie back receptacle 502 and engage a profile machined on the outer surface of the jay type latch seal assembly 506. Torque is required to break these shear screws 518. Although the current design of the jay type latch seal assembly is illustrated as having an anchoring mechanism in the form of three jay pins, it could instead have two or more jay pins, and such embodiments are encompassed by the scope of the present invention. Preferably the seals 512 are bonded seals, although other seal configurations could be used instead, including polypak type seals, o-rings or v-seals. The seal design on the latch seal assembly 506 allows the latch to be removed under differential pressure, thus eliminating seal damage.

A second deployment method that can be used with the cased hole packer 500 is depicted in Figure 6, which uses a collet type latch 536, to deploy the liner and frac string. The collet type latch seal assembly 536 has flexible fingers that can deflect and allow the seal assembly to be stabbed into the receptacle. The flexible collet latch 536 can preferably comprise a tread profile machined on its external surface that matches a similar thread profile machined on the I.D. of the receptacle. The collet type latch seal assembly 536 can preferably be removed from the receptacle by rotating the work string clockwise while picking up, which serves to screw the collet type latch 536 out of the receptacle.

A third deployment method that can be used with the cased hole packer 500 is depicted in Figure 7, in the form of a casing string 538 screwed directly into top of cased hole packer 500. In this case, the casing string is used for both deployment and fracturing and the casing string is not retrieved when the process is complete.

5 In one example of operation of the tools of the present invention, a liner is assembled with the following components, as illustrated in Figure 1: a float shoe 50, the present activation tool 100, a liner, the present first stage frac valve tool 200, and then a series comprising a liner, an open hole packer 300, a liner and a frac valve 400. Optionally, an open hole anchor 600 may be used between the activation tool 100 and the first stage frac valve tool 200 to anchor the
10 liner to the wellbore. Alternative to an open hole anchor 600 centralizers, stabilizers or other suitable means known in the art may also be used for this purpose.

Preferably up to 40 frac valves 400, on a 4 1/2" liner for example, separated with open hole packer 300s can be used in a string. A cased hole packer 500 is attached to the upper end of the casing. A latch seal assembly 506, collet type latch 536 or other known means can be
15 used to attach the cased hole packer 500 to the casing.

The liner is run into the conditioned bore hole by a drill string or on a frac string. At a predetermined depth, ball 104 is circulated down to the activation tool 100 to stop fluid flow. Pressure increase, thereby setting both the cased hole packer 500 and the open hole packers 300. A pressure test may optionally be performed inside the casing to determine if the cased
20 hole packer 500 has set properly. If the liner was run on a drill string, the latch seal assembly 506, collet type latch 536 or other connection means can next be removed from the cased hole packer 500 and the drill string and connecting means are removed from the well and a frac string and associated connecting means are deployed. Otherwise, if the liner was run downhole on a frac string, no replacement has to be made.

25 Further pressure is applied to the frac string. At a pre-determined setting pressure that is higher than the pack off pressure of the open hole packers 300 and cased hole packer 500, the first stage frac valve tool 200 shifts to the open position and stimulation fluid is pumped into the formation to stimulate the formation from the toe of the wellbore to the first stage frac valve tool 200. Proppant is then pumped into the fracture. Next subsequent frac valve

tools 400, starting with that closest to the first stage frac valve tool 200, are activated to thereby open communication between the inside of the liner and the isolated section of the formation between the two open hole packer 300 straddling the particular frac valve 400.

The stimulation fluid pumped through the ports of the frac valve 400 fractures the exposed formation between the open hole packers 300 used to isolate that stage. Whenever this stage has been fractured, a next frac valve 400 is activated and the process is repeated. The process can be repeated up to 40 times in total in a 4 ½" liner, for example. Other sizes of liners can have a different number of frac valve tools 400 and open hole packers 300. When all the desired stages have been fractured, the well is allowed to flow and formation pressure from formation fluid flow acts to deactivate the frac valves 400 and allows formation fluid flow into the liner. Afterwards the frac string and connecting means can be removed from the well.

In the case of ball drop activated frac valve tools 400, if desired, the seats of the frac valves 400 can be drilled out at a later date.

In the event the operator needs to set the liner in an open hole, an open hole anchor 600, illustrated in Figure 8 can replace the cased hole packer 500. This scenario can exist whenever dual horizontals are drilled in one well, as seen in Figure 9. The hydraulic set open hole anchor 600 is full bore. It is run in conjunction with an open hole packer 300 and tie back receptacle (not shown) to act as a means to seal and anchor the liner in the open hole. The tieback receptacle provides a means to deploy the liner then act as a means to seal and anchor the fracture string to the liner.

The open hole anchor 600 is preferably full bore with no mandrel restrictions and has the same I.D. as the liner. Preferably it is operated with slips 602 to anchor the liner to the formation. More preferably the open hole anchor 600 employs a similar setting piston and ratchet configurations of the cased hole packer 500.

Preferably, after the bore hole has been drilled and before the liner is installed, a reamer trip is performed. The present reamer has a unique design to mimic the geometry of the stiffest components on the liner string. The present reamer has one set of blades instead of multiple sets and its reduced O.D. and short length enable it to be deployed and retrieved quickly while still ensuring the bore hole has no obstructions to impede running the liner with

the present suite of fracturing tools. The reamer preferably has a small O.D. and a short length to mimic the geometry of the present tools of the frac string illustrated in Figure 1. The geometry of the reamer permit ease of deployment and in some circumstances allows the reamer to travel to the toe end of the frac string without needing to ream any tight spots in the wellbore. This reduces rig time while ensuring that the present frac tools can be deployed into the wellbore.

In the foregoing specification, the invention has been described with specific embodiments thereof; however, it will be evident that various modifications and changes may be made thereto without departing from the scope of the invention.

Claims

1. An activation tool for use in a well isolation and stimulation string, said activation tool comprising:
 - a. a stationary seat for receiving a ball deployed down the string;
 - 5 b. a stationary inner body;
 - c. a stationary outer body; and
 - d. an internal sleeve positioned between the stationary inner and stationary outer bodies, said internal sleeve being shiftable from an open position to a closed position by force of the ball against the seat, said internal sleeve further comprising:
 - 10 i. a collet integrally connected to the internal sleeve and shiftable to lock the moving internal sleeve in the closed position,
 wherein the internal sleeve and the collet are shiftable with a single stroke.
2. The activation tool of claim 1, wherein deployment of the ball onto the seat prevents circulation of liner fluid through the activation tool and re-directs fluid into a chamber
 - 15 formed between the stationary inner body and the moving sleeve, said fluid acting to move the sleeve.
3. The activation tool of claim 2, further comprising one or more shears screws affixing the stationary inner body to the moving sleeve, said shear screws being shearable at a
 - 20 predetermined liner fluid accumulated in the tool when the ball lands on the seat, wherein shearing of said one or more shear screws allows the moving sleeve to shift to the closed position.
4. A method of closing an activation tool on a stimulation string, said method comprising:
 - 25 a. deploying a ball down the stimulation string to the activation tool;

- b. receiving the ball on a stationary seat of the activation tool;
- c. shifting an internal sleeve being from an open position to a closed position by force of the ball against the seat; and
- d. shifting a collet integrally connected to the internal sleeve to lock the internal sleeve in the closed position,

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wherein the internal sleeve and the collet are shifted in a single stroke.

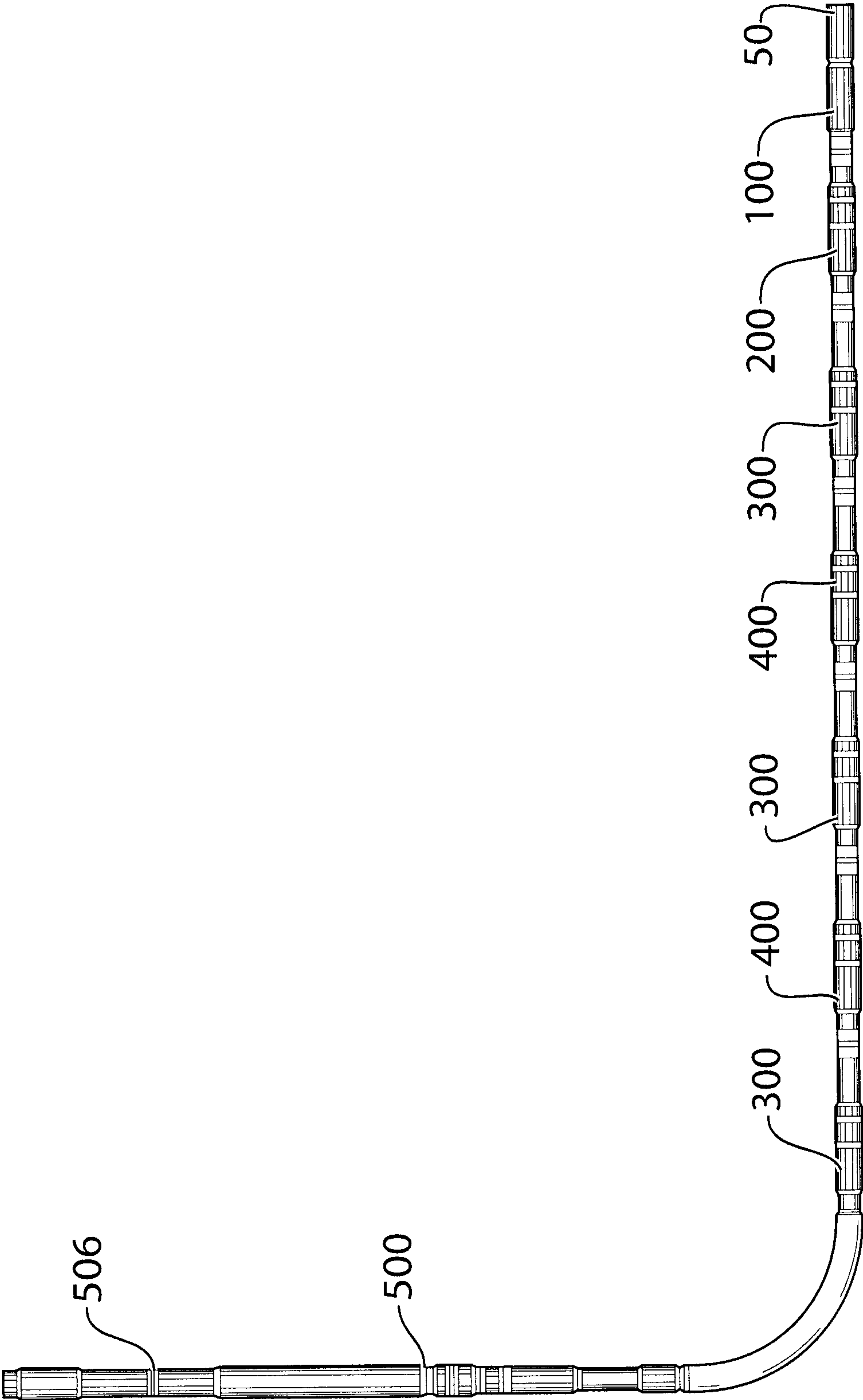
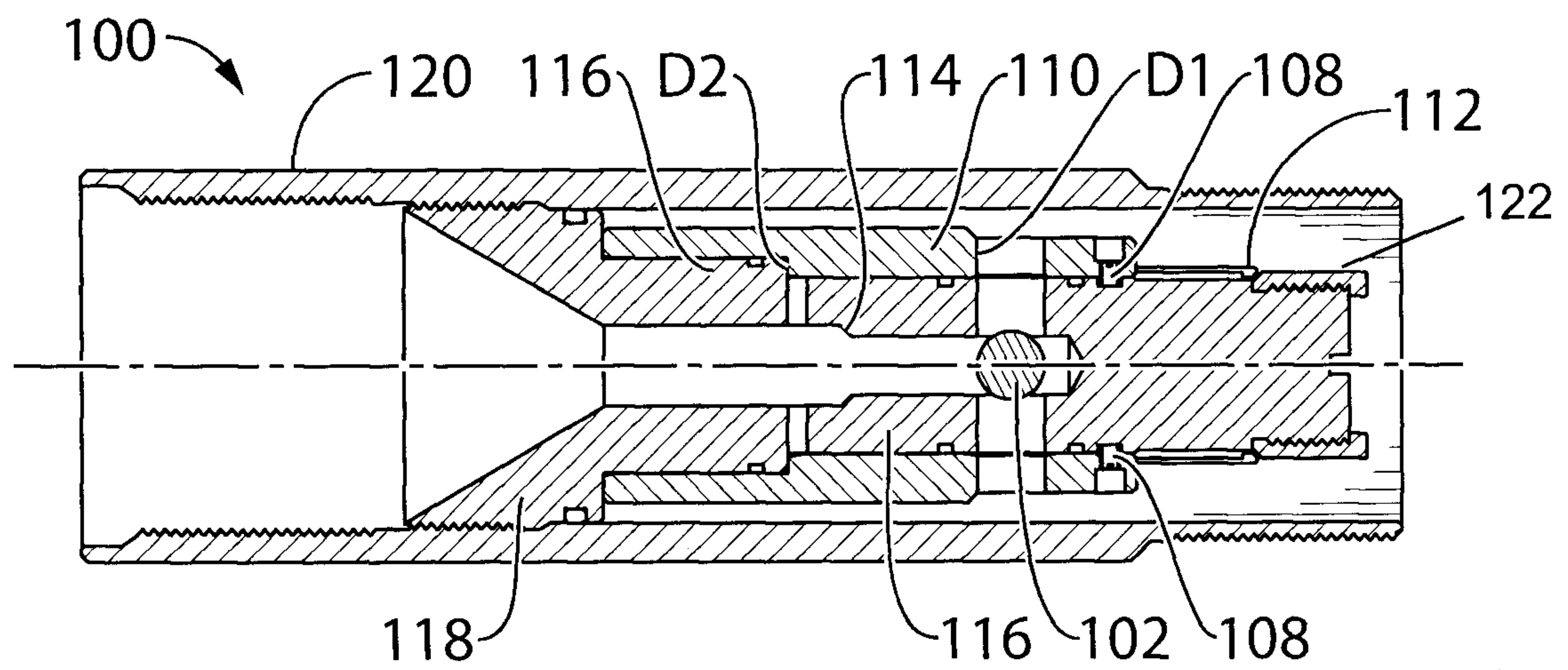
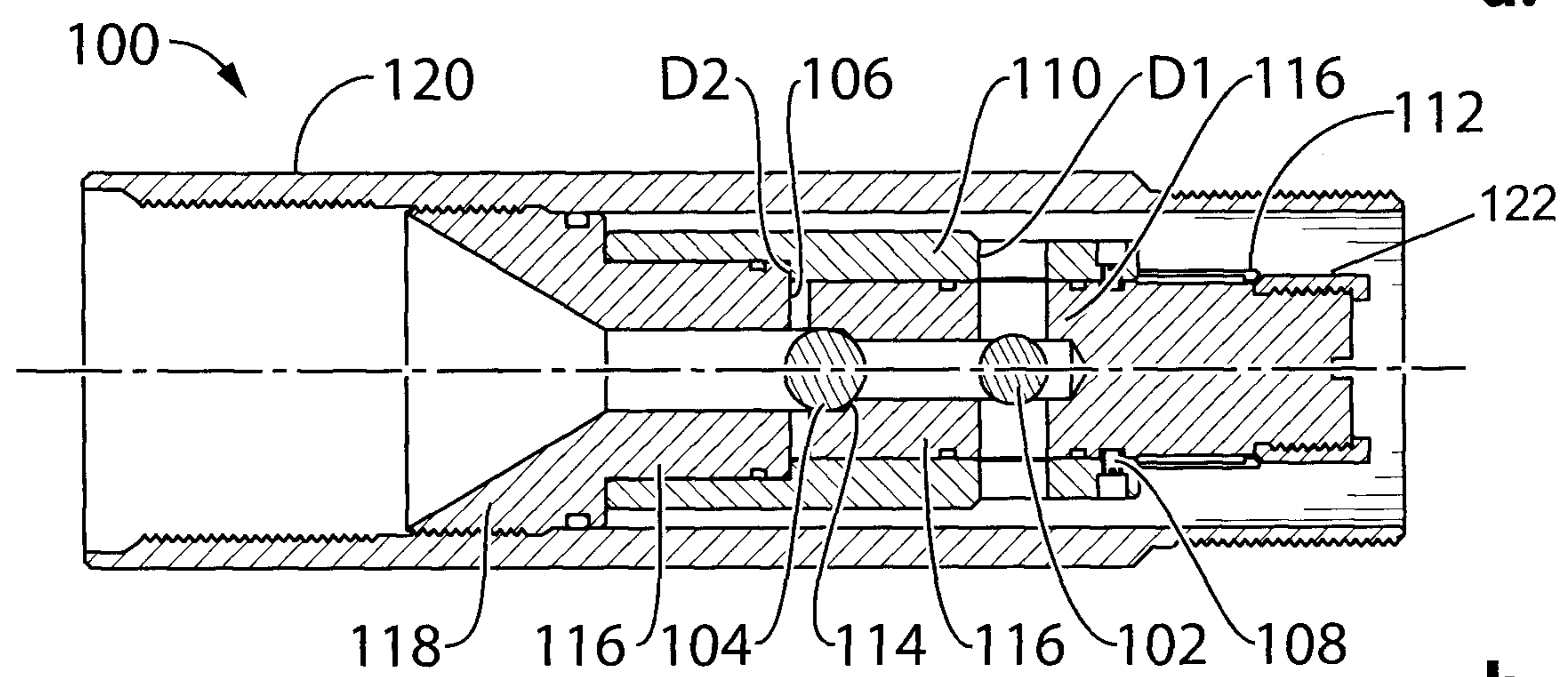
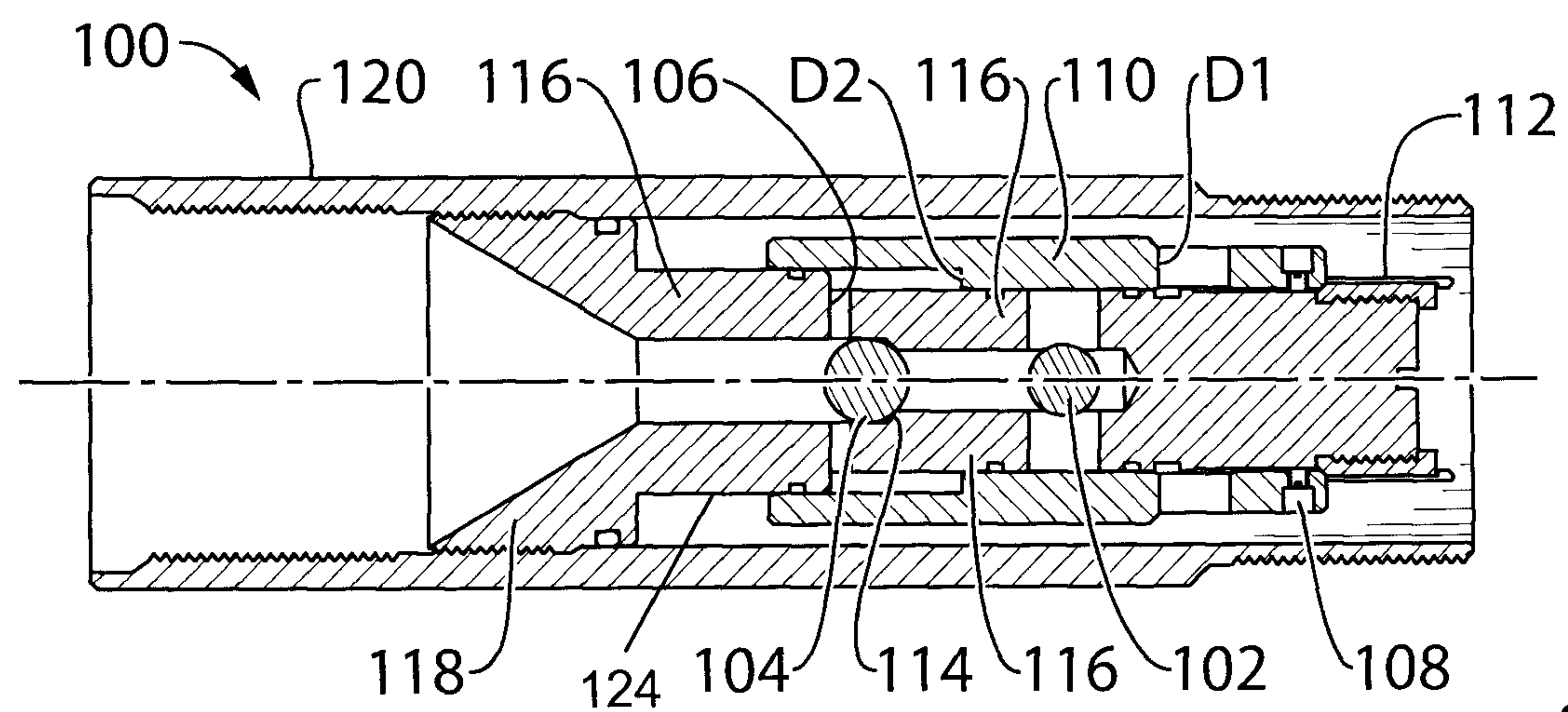
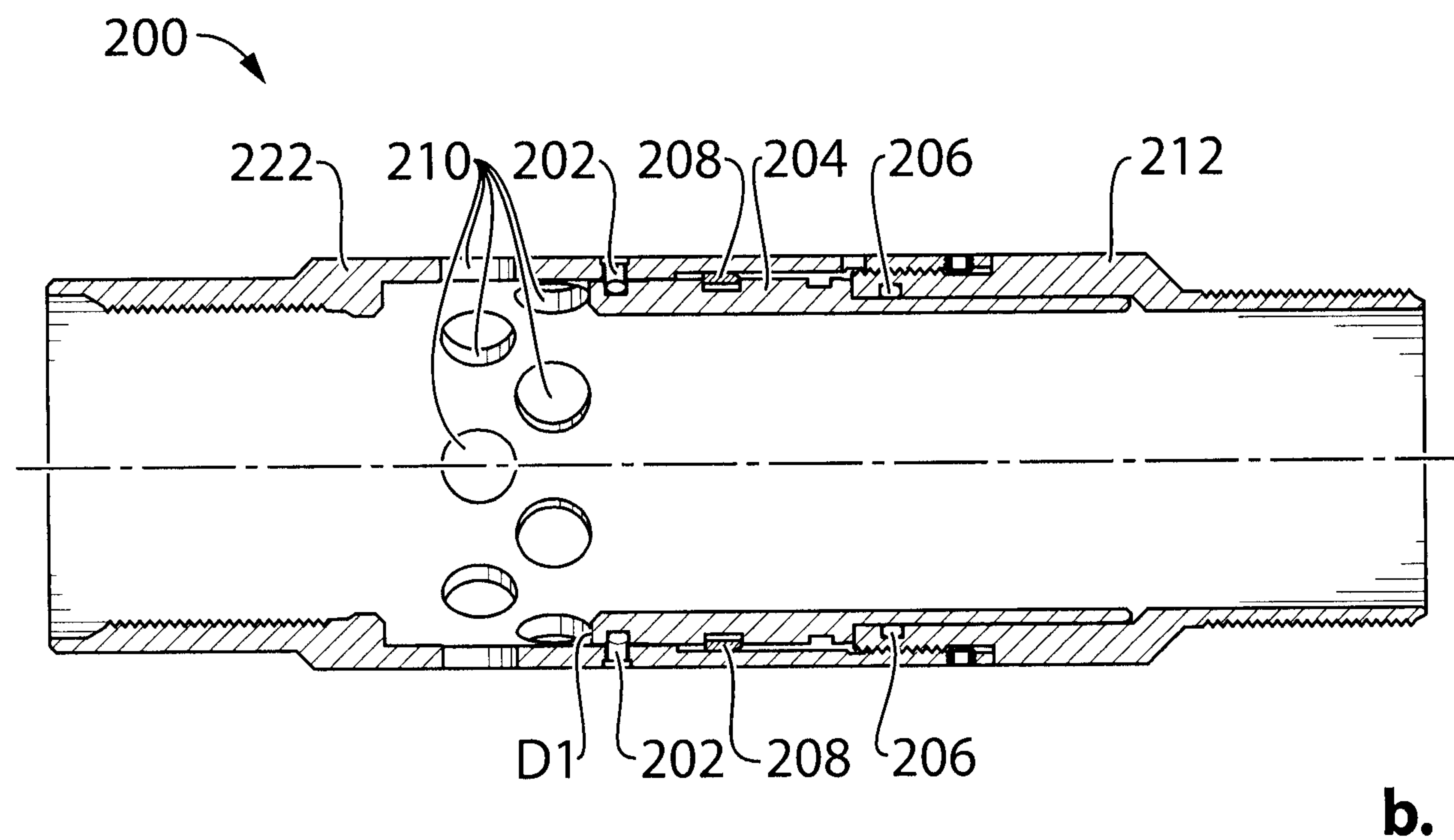
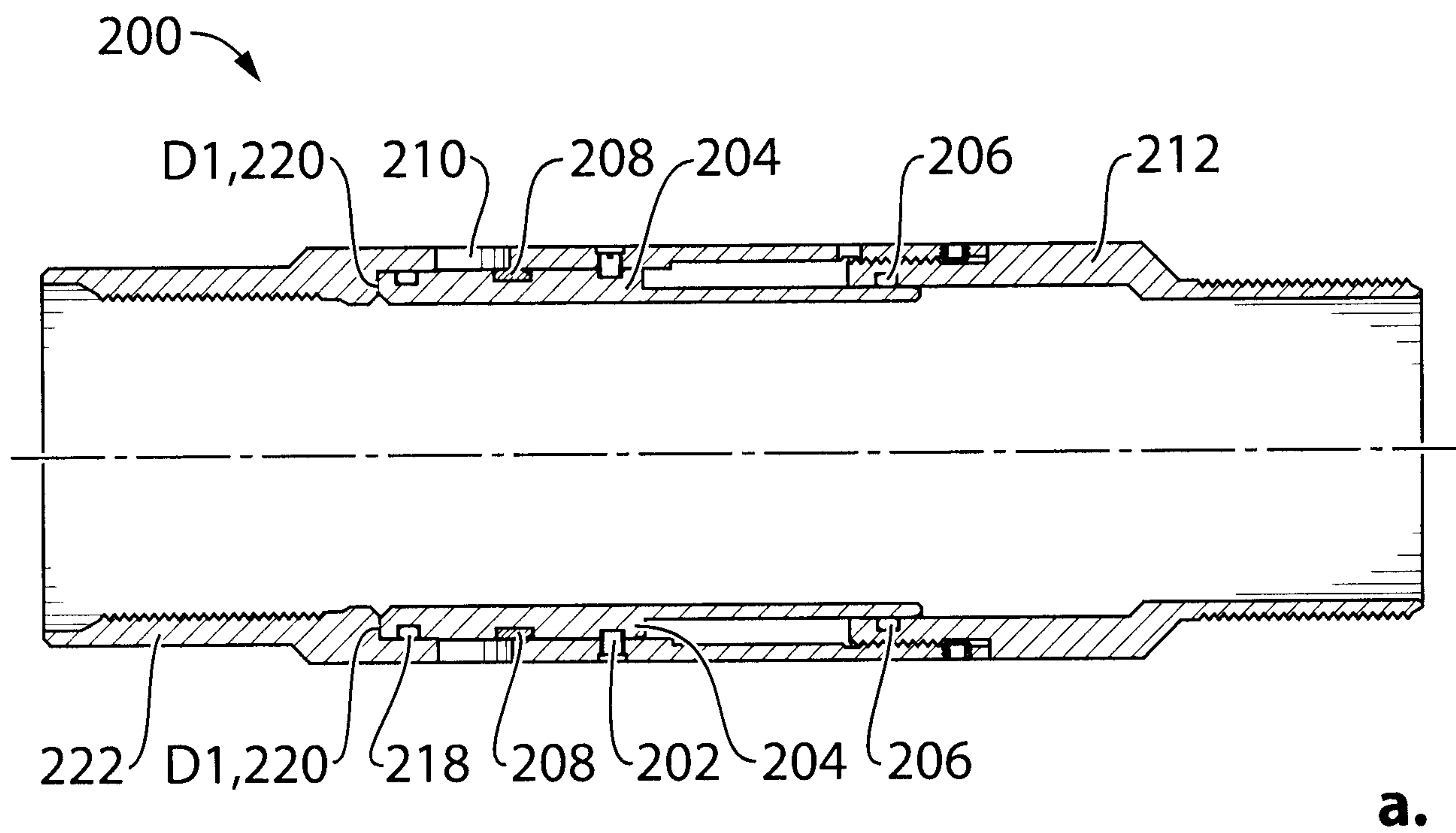


FIG. 1

**a.****b.****c.****FIG.2**

**FIG.3**

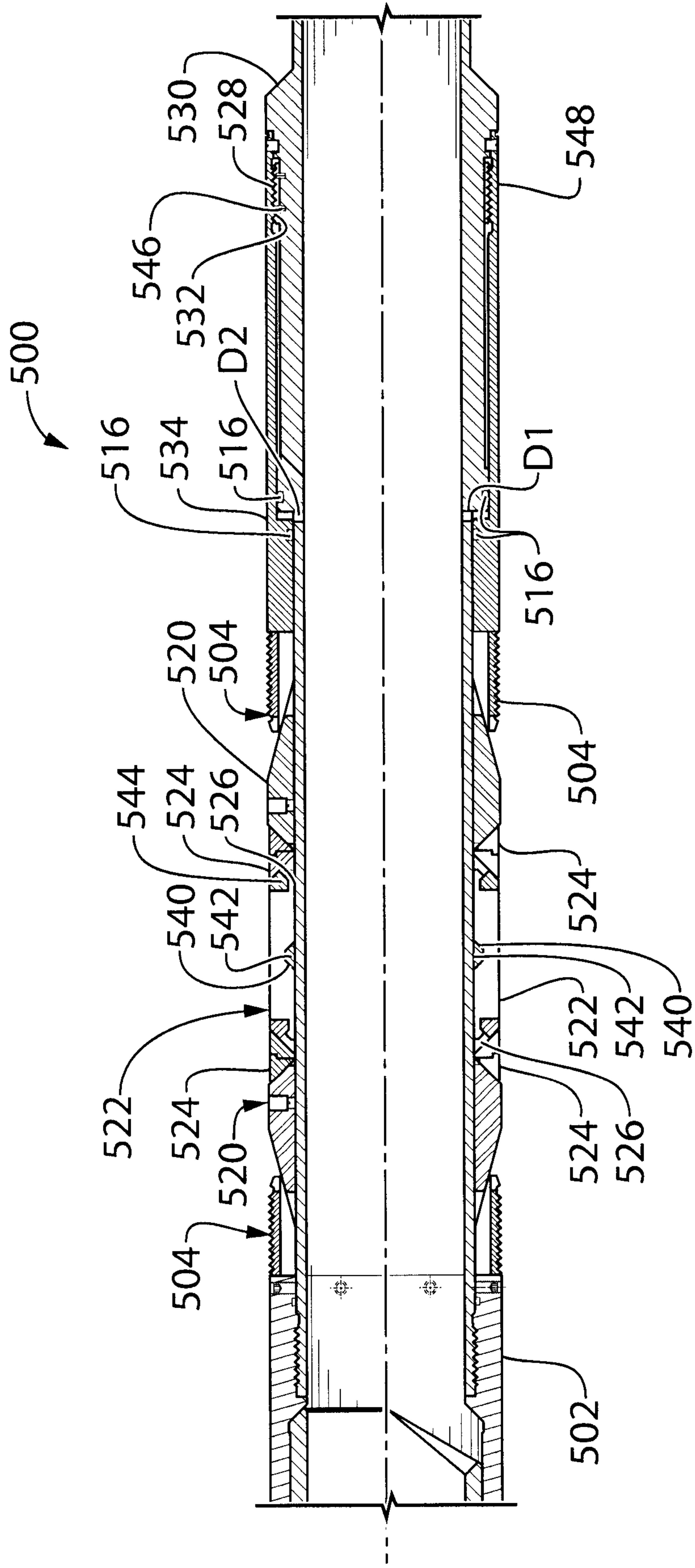


FIG. 4

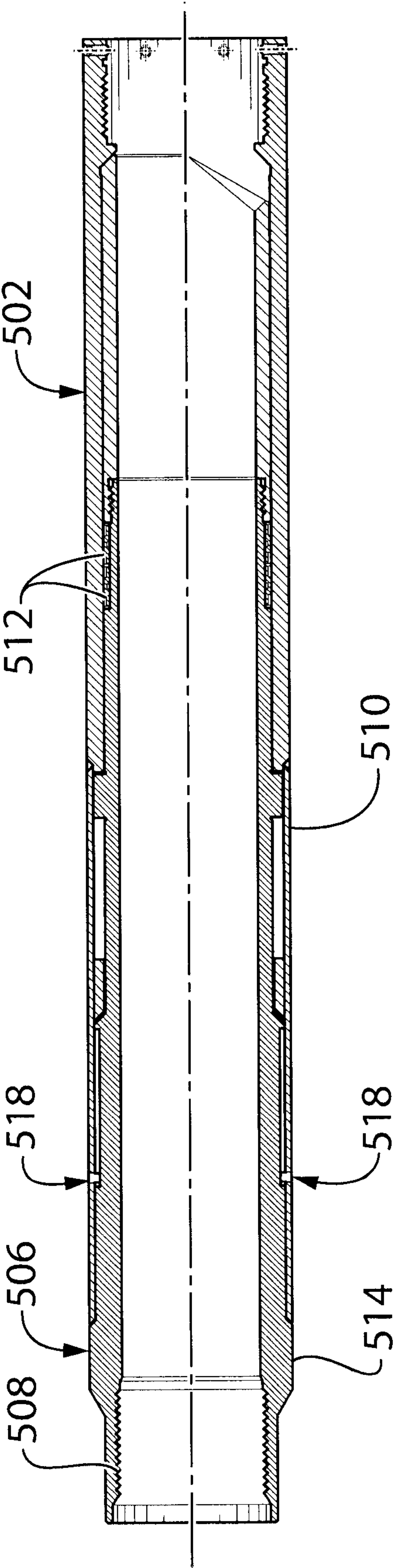


FIG.5

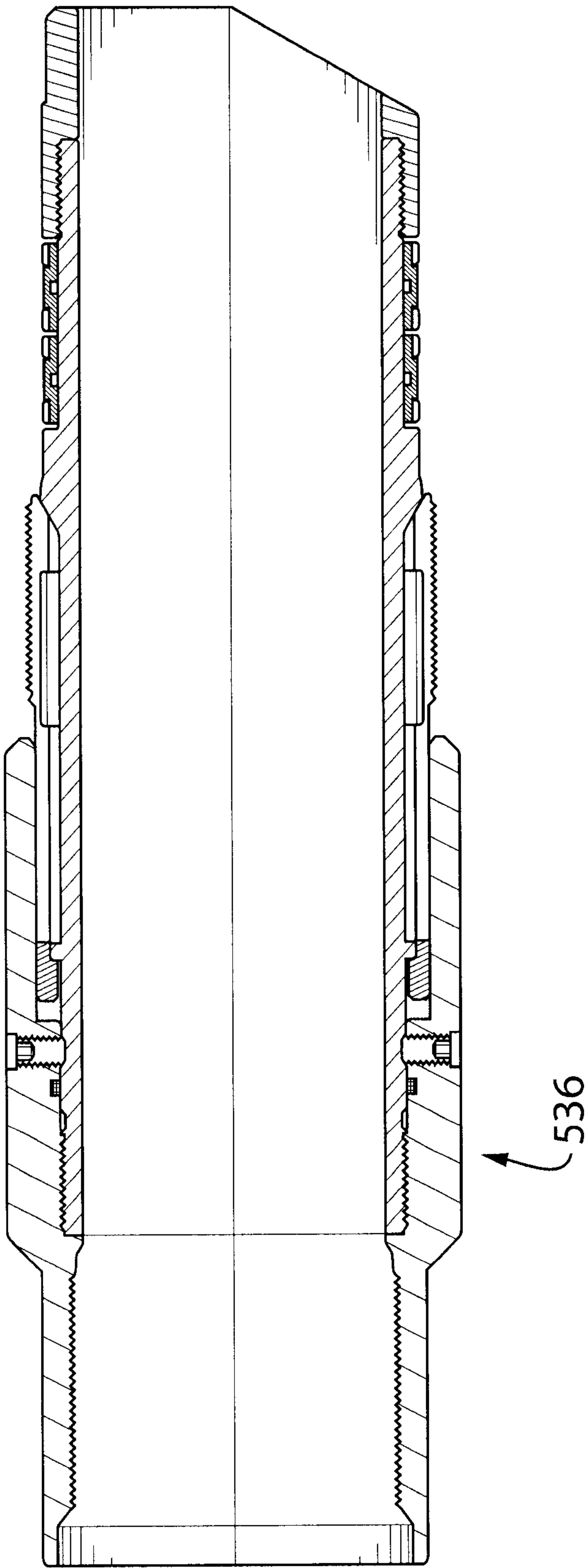


FIG. 6

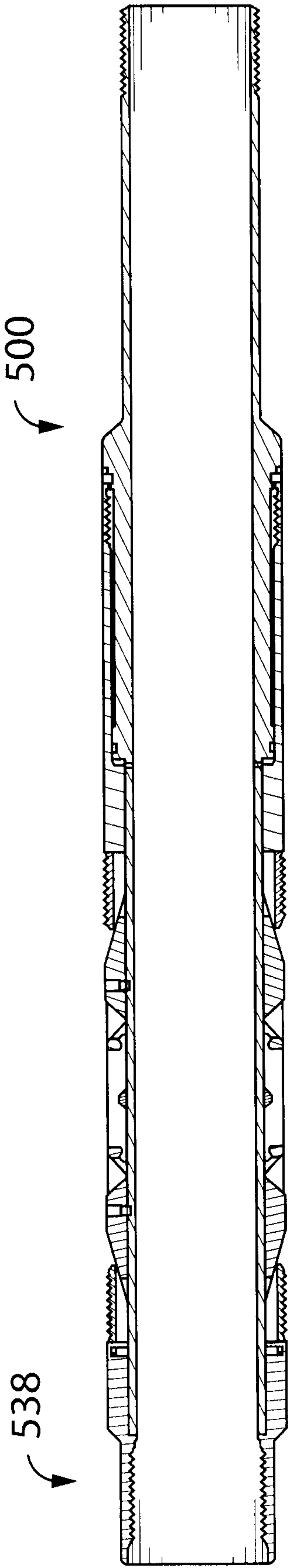


FIG. 7

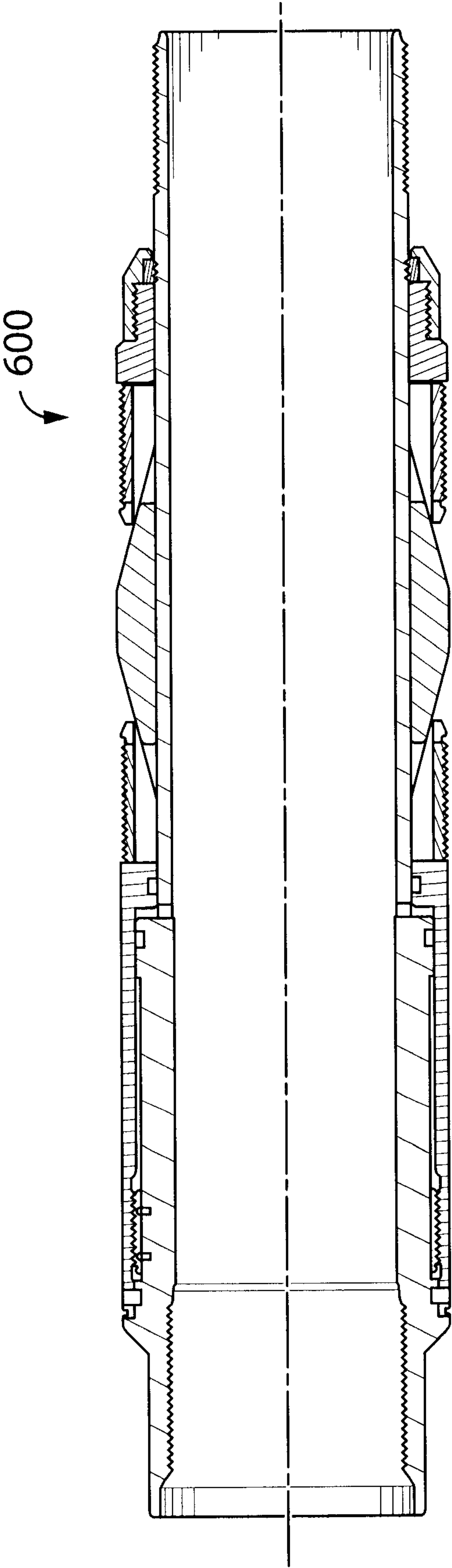


FIG. 8

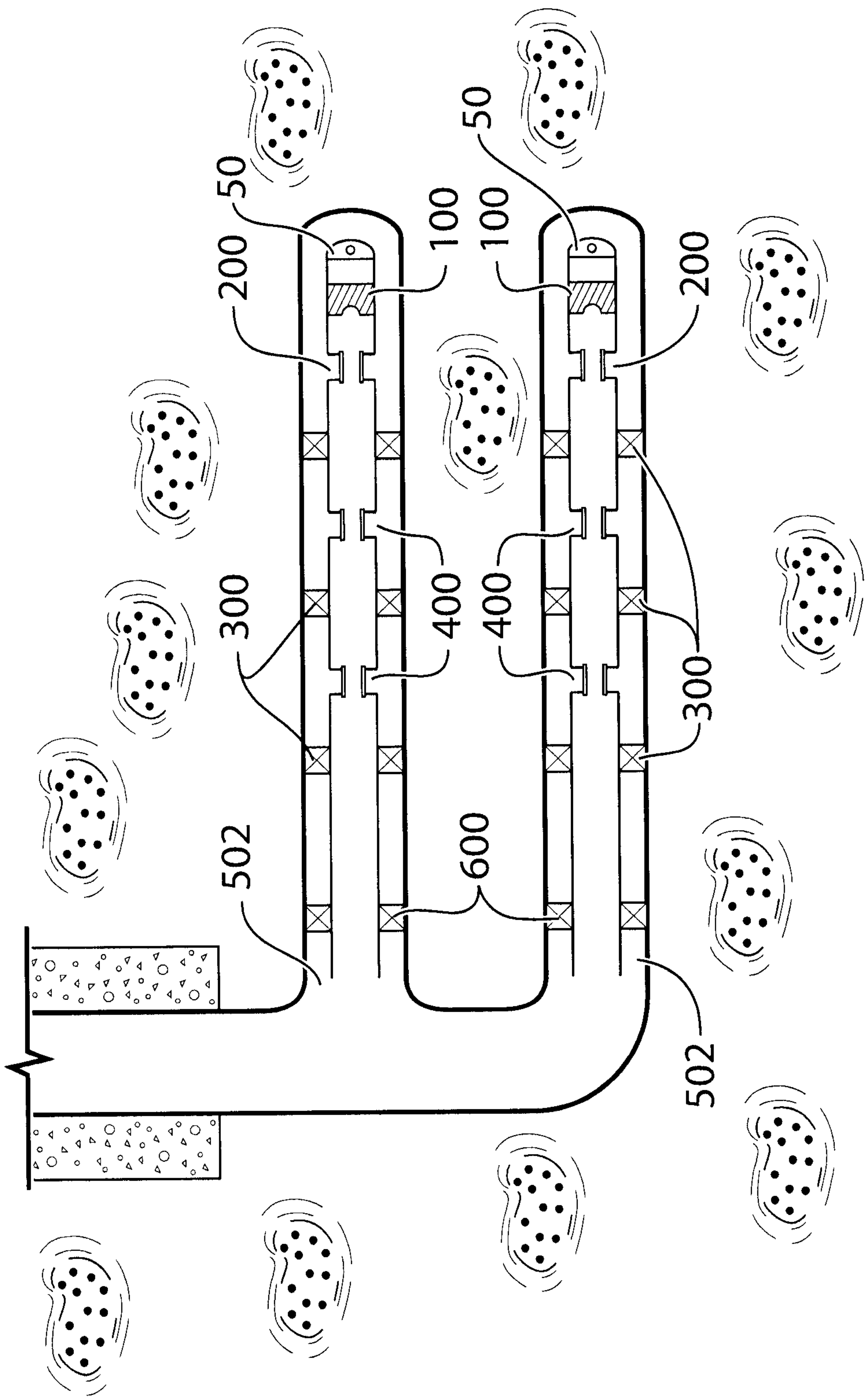


FIG. 9

