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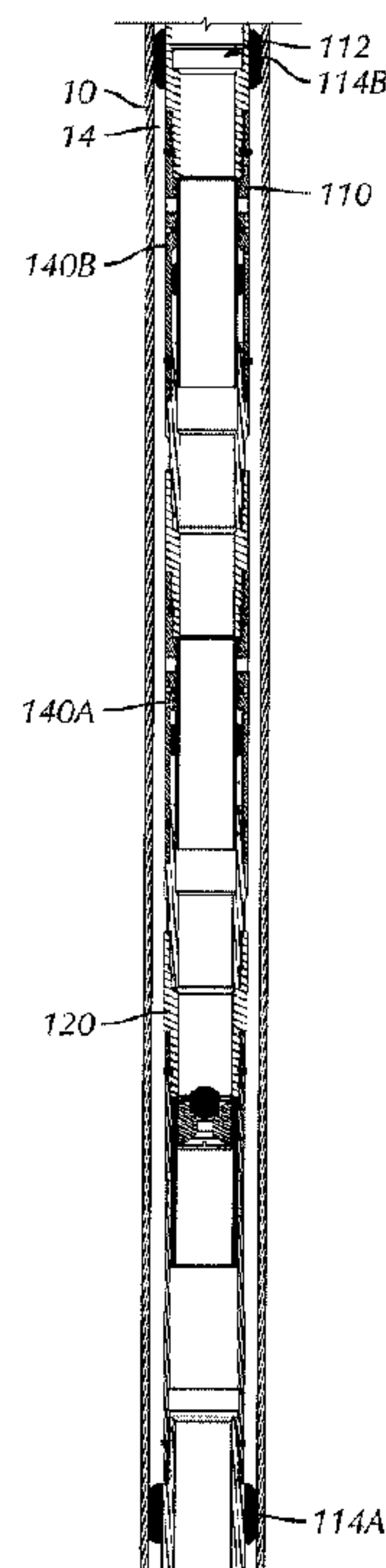
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PRESSION

(54) Title: ARRANGEMENT OF ISOLATION SLEEVE AND CLUSTER SLEEVES HAVING PRESSURE CHAMBERS



(57) Abrégé/Abstract:

For wellbore fluid treatment, sliding sleeves deploy on tubing in a wellbore annulus. Operators deploy a plug down the tubing to a first sleeve. The plug seats in this first sleeve, and pumped fluid pressure opens the first sleeve and communicates from the tubing to the wellbore annulus. In the annulus, the fluid pressure creates a pressure differential between the wellbore annulus pressure and a pressure chamber on second sleeves on the tubing. The resulting pressure differential opens the second sleeves so that fluid pressure from the tubing can communicate through the second open sleeves. Using this arrangement, one sleeve can be opened in a cluster of sleeves without opening all of them at the same time. The deployed plug is only required to open the fluid pressure to the annulus by opening the first sleeve. The pressure chambers actuate the second sleeves to open up the tubing to the annulus.



ABSTRACT

For wellbore fluid treatment, sliding sleeves deploy on tubing in a wellbore annulus. Operators deploy a plug down the tubing to a first sleeve. The plug seats in
5 this first sleeve, and pumped fluid pressure opens the first sleeve and communicates from the tubing to the wellbore annulus. In the annulus, the fluid pressure creates a pressure differential between the wellbore annulus pressure and a pressure chamber on second sleeves on the tubing. The resulting pressure differential opens the second sleeves so that fluid pressure from the tubing can communicate through the second
10 open sleeves. Using this arrangement, one sleeve can be opened in a cluster of sleeves without opening all of them at the same time. The deployed plug is only required to open the fluid pressure to the annulus by opening the first sleeve. The pressure chambers actuate the second sleeves to open up the tubing to the annulus.

ARRANGEMENT OF ISOLATION SLEEVE AND CLUSTER SLEEVES HAVING PRESSURE CHAMBERS

FIELD OF THE INVENTION

5 Embodiments described herein relate to wellbore fluid treatment methods. More particularly, the embodiments relate to isolating zones of a formation and treating the isolated zones with treatment fluid diverted to the isolated zones through cluster sleeves deployed on a tubing string. The cluster sleeves are configured to open at specified pressures for diverting treatment fluid to the isolated zones. The cluster
10 sleeves are also configured such that one sleeve can be opened in a cluster of sleeves without opening all of them at the same time.

BACKGROUND

 In a staged frac operation, multiple zones of a formation need to be
15 isolated sequentially for treatment. To achieve this, operators install a frac assembly down the wellbore. Typically, the assembly has a top liner packer, open hole packers isolating the wellbore into zones, various sliding sleeves, and a wellbore isolation valve. When the zones do not need to be closed after opening, operators may use single shot sliding sleeves for the frac treatment. These types of sleeves are usually ball-actuated
20 and lock open once actuated. Another type of sleeve is also ball-actuated, but can be shifted closed after opening.

 Initially, operators run the frac assembly in the wellbore with all of the sliding sleeves closed and with the wellbore isolation valve open. Operators then deploy a setting ball to close the wellbore isolation valve. This seals off the tubing string
25 so the packers can be hydraulically set. At this point, operators rig up fracing surface equipment and pump fluid down the wellbore to open a pressure actuated sleeve so a first zone can be treated.

 As the operation continues, operators drop successively larger balls down the tubing string and pump fluid to treat the separate zones in stages. When a dropped
30 ball meets its matching seat in a sliding sleeve, the pumped fluid forces against the seated ball and shifts the sleeve open. In turn, the seated ball diverts the pumped fluid

into the adjacent zone and prevents the fluid from passing to lower zones. By dropping successively increasing sized balls to actuate corresponding sleeves, operators can accurately treat each zone up the wellbore.

5 Because the zones are treated in stages, the lowermost sliding sleeve has a ball seat for the smallest sized ball size, and successively higher sleeves have larger seats for larger balls. In this way, a specific sized dropped ball will pass through the seats of upper sleeves and only locate and seal at a desired seat in the tubing string. Despite the effectiveness of such an assembly, practical limitations restrict the number of balls that can be run in a single tubing string. Moreover, depending on the formation
10 and the zones to be treated, operators may need a more versatile assembly that can suit their immediate needs.

The subject matter of the present disclosure is directed to overcoming, or at least reducing the effects of, one or more of the problems set forth above.

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SUMMARY

In wellbore fluid treatment such as a fracing operation, sliding sleeves deploy on a tubing string in a wellbore annulus. To isolate a zone of the wellbore, the tubing string has packing elements disposed thereon. For a given zone, the tubing string has a first isolation sleeve and one or more second cluster sleeves disposed
20 between the packing elements. The isolation sleeve can be disposed downhole of the one or more second cluster sleeves on the tubing string or in some other arrangement.

To treat the zone, operators deploy a plug down the tubing string to the isolation sleeve. The plug seats in an internal sleeve of this isolation sleeve, and fluid pressure pumped down the tubing string forces the first sleeve open. The diverted fluid
25 pressure then communicates from the isolation sleeve to the wellbore annulus.

Communicated in the wellbore annulus, the fluid pressure produces a pressure differential between the wellbore annulus pressure and the pressure chambers on the cluster sleeves disposed on the tubing string. The pressure differential between the pressure chambers and the wellbore annulus then opens the cluster sleeves so that
30 fluid pressure from the tubing string can communicate through these open sleeves.

Using this arrangement, one isolation sleeve can be opened in a cluster of sleeves without opening all of them at the same time. The ball is not required to open each sleeve of the cluster. Instead, the ball is only required to open the tubing pressure to the annulus by opening the isolation sleeve. Then, the pressure chambers actuate
5 the cluster sleeves to open up more of the tubing string to the surrounding annulus.

To open the cluster sleeves, the fluid pressure after the isolation sleeve has been opened travels down the tubing string and into the isolated annulus of the zone. The cluster sleeves with their pressure chambers are set to withstand the hydrostatic pressure downhole within an acceptable margin. Yet, fluid pressure in the
10 wellbore annulus equalizes with the tubing string's pressure. The pressure chambers on the cluster sleeves are actuated by the applied pressure in the annulus, and the cluster sleeves shift open so more of the isolated zone can be treated because the pressure chambers have a lower pressure.

Overall, the cluster sleeves act independent of the tubing pressure and
15 independent of each other. In fact, each cluster sleeve in the isolated zone can be configured to open at specified pressures that can be different from or the same as other clusters sleeves in the isolated zone. Operators can ensure all of the sliding sleeves open for maximum coverage per zone and can tailor the opening according to particular purposes.

20 The foregoing summary is not intended to summarize each potential embodiment or every aspect of the present disclosure.

BRIEF DESCRIPTION OF THE DRAWINGS

Fig. 1 diagrammatically illustrates a tubing string having multiple sliding
25 sleeves according to the present disclosure.

Fig. 2 shows a cross-section of one arrangement of sliding sleeves on a tubing string according to the present disclosure.

Figs. 3A-3B show portions of the tubing string of Fig. 2, revealing details of the cluster sleeves.

30 Fig. 3C shows another portion of the tubing string of Fig. 2, revealing details of the isolation sleeve.

Figs. 4A-4C show portions of the tubing string of Fig. 2 in stages of opening.

Fig. 5 shows a cross-section of another arrangement of sliding sleeves on a tubing string according to the present disclosure.

5 Figs. 6A-6B show portions of the tubing string of Fig. 5, revealing details of the cluster sleeves.

Fig. 6C shows another portion of the tubing string of Fig. 5, revealing details of the isolation sleeve.

10 Figs. 7A-7C show portions of the tubing string of Fig. 5 in stages of opening.

Figs. 8A-8B diagrammatically illustrate a tubing string having alternate arrangements of sliding sleeves according to the present disclosure.

DETAILED DESCRIPTION

15 A tubing string 110 shown in Figure 1 deploys in a wellbore 10. The string 110 has an isolation sliding sleeve 120 and cluster sliding sleeves 130A-B disposed along its length. A pair of packing elements or other isolation devices 114A-B isolate portion of the wellbore 10 into an isolated zone. Disposed between the packing elements 114A-B, the sliding sleeves 120 and 130A-B can divert treatment fluid to the
20 isolated zone of the surrounding formation. The treatment fluid can be frac fluid having proppant pumped at high pressure or can be other suitable type of fluid (with or without additive) to treat a zone of the wellbore.

The tubing string 110 can be part of a frac assembly 20, for example, having a top liner packer (not shown), a wellbore isolation valve (not shown), and other
25 packers and sliding sleeves (not shown) in addition to those shown. Alternatively, the tubing string 110 can be part of a completion assembly or other suitable assembly. In general, the wellbore 10 can be an opened or cased hole, and the packing elements 114A-B can be any suitable type of element or packer intended to isolate portions of the wellbore into isolated zones. The wellbore 10 can be an open hole, or can have a
30 casing. If a cased hole, the wellbore 10 can have casing perforations 16 at various points as shown.

As conventionally done for a fracing assembly 20, for example, operators deploy a setting ball to close a wellbore isolation valve (not shown) downhole, rig up fracing surface equipment (e.g., pump system 35 and the like), pump fluid down the wellbore, and open a pressure actuated sleeve (not shown) downhole so a first zone
5 can be treated. Eventually in a later stage of the operation, operators actuate the sliding sleeves 120 and 130A-B between the packing elements 114A-B to treat the isolated zone depicted in Figure 1.

Briefly, the isolation sleeve 120 has a seat (not shown). When operators drop a specifically sized plug (e.g., ball, dart, or the like) down the tubing string 110, the
10 plug engages the isolation sleeve's seat. (For purposes of the present disclosure, the plug is described as a ball, although the plug can be any other acceptable device.) As fluid is pumped by the pump system 35 down the tubing string 110, the seated ball opens the isolation sleeve 120 so the pumped fluid can be diverted out ports to the surrounding wellbore 10 between the packers 114A-B.

15 In contrast to the isolation sleeve 120, the cluster sleeves 130A-B have pressure chambers (not shown) according to the present disclosure, which are described in more detail later. These pressure chambers are at low or atmospheric pressure, but are configured to withstand the hydrostatic pressure expected at the particular depth downhole. When the specifically sized ball is dropped down the tubing
20 string 110 to engage the isolation sleeve 120, the dropped ball passes through the cluster sleeves 130A-B without opening them. Once the isolation sleeve 120 is opened, however, the fluid pressure pumped down the tubing string 110 enters the isolated annulus 14 of the wellbore 10 and creates a pressure differential between the wellbore annulus and the pressure chambers of the cluster sleeves 130A-B.

25 As pressure builds in the wellbore annulus 14, for example, the cluster sleeves 130A-B are activated by the pressure differential against their pressure chambers and any shear pins or other temporary retaining features. Eventually, the cluster sleeves 130A-B open and allow the communicated fluid in the tubing string 110 to enter the isolated annulus 14 through the open ports of these cluster sleeves 130A-B.
30 In this way, one sized ball can be dropped down the tubing string 110 past a cluster of sliding sleeves 130A-B to treat an isolated zone. The sleeves 120 and 130A-B can

divert the fluid pressure along the length of the tubing string 110 and at particular points in the wellbore 10. For example, the particular points can be adjacent certain perforations 16 if the wellbore 10 has casing 12, or they can be certain areas of the open hole if uncased.

5 With a general understanding of how the sliding sleeves 120 and 130A-B are used, attention now turns to further details of a tubing string, isolation sleeve, and cluster sleeves according to the present disclosure.

10 One arrangement of a tubing string 110 shown in Figure 2 defines a through-bore 112 and has packing elements 114A-B on both ends. Although shown as packing sleeves, these elements 114A-B can be any suitable type of packing or sealing element, either active or passive, known in the art. At the downhole end, the string 110 has an isolation sleeve 120. Uphole from this, the string 110 has one or more cluster sleeves 140A-B. Although two cluster sleeves 140A-B are shown in this example, the string 110 may have any number.

15 The isolation sleeve 120 shown in detail in Figure 3C has an internal sleeve or insert 122 movably disposed in a housing 121 that forms part of the tubing string 110. This internal sleeve 122 can move relative to external ports 123 in bore of the housing 121. A seat 124 on the internal sleeve 122 engages with a dropped ball 126 or other type of plug when deployed from uphole.

20 The cluster sleeves 140A-B shown in Figures 3A-3B each have an internal sleeve or insert 142 movably disposed in a housing 141 that forms part of the tubing string 110. (The housing 141 has upper, lower, and intermediate portions that couple together, which facilitates assembly.) The internal sleeve 142 can move relative to external ports 143 in a bore of the housing 141. In the annular space between the
25 internal sleeve 142 and the housing 141, the internal sleeve 142 defines a first (hydrostatic pressure) chamber 144 isolated from a second chamber 146 by a seal ring 125. The first chamber 144 is closed and is at a low or preset pressure, such as atmospheric. The second chamber 146 communicates with an inlet port 147 communicating with the annulus surrounding the string 12. Shear pins 148 hold the
30 internal sleeve 142 in its closed condition covering the external ports 143.

Figures 4A-4C show portions of the tubing string 110 in stages of opening. Initially, the isolation sleeve 120 and cluster sleeves (only one 140A shown) deploy downhole in a closed condition as shown in Figure 4A. The packing elements (114A-B; Fig. 2A) engage the surrounding sidewall of the wellbore 10 to isolate a zone of the annulus.

To begin activating the sleeves, operators drop a suitably sized ball 126 or other type of plug down the tubing string 110. Above the present arrangement on the string 110, the dropped ball 126 may pass any number of other arrangements of similar configured sleeves for other isolated zones. However, these other arrangements have isolation sleeves configured to engage larger sized balls 126 or plugs. Therefore, the present ball 126 or plug passes through these uphole isolation sleeves without opening them.

In any event, the dropped ball 126 engages with the isolation sleeve's seat 124 as shown in Figure 4A. The seated ball 126 now isolates the uphole portion of the string's bore 112 from any additional components downhole from the present arrangement.

At this point, operators pump fluid down the string's bore 112, and the pressure from the fluid acts against the seated ball 126. When the force reaches a configured limit, a holding ring 128, shear pins, or other affixing elements break, and the fluid pressure pushes the seated ball 126 and sleeve 122 downhole in the housing 121 as shown in Figure 4B. As it moves, the sleeve 122 reveals the external ports 123 in the housing 121 so fluid can enter the wellbore annulus 14. As the sleeve 122 reaches its limit, dogs or a lock ring 129 on the sleeve 122 engage in a profile in the housing 121 to keep the sleeve 122 in the open condition.

The fluid pressure in the annulus 14 reaches the inlet port 147 on the cluster sleeve 140A. Pressure entering the port 147 fills the second chamber 146 and acts against the seal ring 145 on the sleeve 142. This seal ring 145 is affixed to the internal sleeve 142 and has seals engaging both the internal sleeve 142 and housing 141. As pressure fills the second chamber 146, a pressure differential develops between the first and second chambers 144 and 146. Eventually as shown in Figure 4C, the fluid pressure breaks the shear pins 148 and forces the internal sleeve 142

downward in the housing 141. This movement reveals the exit ports 143 for the cluster sleeve 140A so that fluid pressure communicated down the tubing string 110 can enter the annulus 14 at the locations of these ports 143.

As can be seen in the present embodiment, one dropped ball 126 or other plug can be used to open multiple sliding sleeves 120/140A-B to treat a length of isolated formation. The isolation sleeve 120 is open by engagement of the ball 126 followed by application of fluid pressure. The one or more cluster sleeves 140A-B are opened subsequently once the fluid pressure in the isolated annulus 14 activates these sleeves 140A-B to open. A number of ways can be used to have the fluid pressure in the isolated annulus 14 activate the pressure chambers 144 of the cluster sleeves 140A-B. The previous embodiment used fluid pressure applied through a port 147 in the sleeve's housing 141 to create a pressure differential to move the internal sleeve 142 of the cluster sleeves 140A-B open. Another arrangement is described below with reference to Figures 5 through 7C.

As shown in Figure 5, the tubing string 110 again has a through-bore 112 and packing elements 114A-B as before. At the downhole end, the tubing string 110 has an isolation sleeve 120 similar to that described previously. Uphole from this, the string 110 has one or more cluster sleeves 160A-B. Although two cluster sleeves 160A-B are shown in this example, the tubing string 110 may have any number.

As before, the isolation sleeve 120 shown in detail in Figure 6C has an internal sleeve 122 movably disposed in a housing 121 relative to external ports 123. A seat 124 on the internal sleeve 122 engages a dropped ball 126 or other type of plug.

The cluster sleeves 160A-B shown in Figures 6A-6B each have an internal sleeve 162 and an external sleeve 164. The internal sleeve 162 remains fixed between upper and lower ends 161a-b and defines exit ports 163. (In other words, the housing of the cluster sleeve 160A-B is formed from upper and lower ends 161a-b and intermediate internal sleeve 162, which facilitates assembly.)

The external sleeve 164 is disposed on the internal sleeve 162 and can move relative to the exit ports 163. The external sleeve 164 defines an isolated pressure chamber 166 in the annular space between the internal and external sleeves 162 and 164. A sealing sleeve 165 or portion of the lower housing end 161A affixes

against the internal sleeve 162 and has sealing elements sealing against the internal and external sleeves 162/164. The isolated chamber 166 is sealed and is at a low or preset pressure, such as atmospheric. The external sleeve 164 defines a pressure port or shoulder 167 against which pressure can act. Finally, shear pins 148 hold the
5 external sleeve 164 in its closed condition covering the external ports 163.

Figures 7A-7C show portions of the disclosed arrangement on the tubing string 110 in stages of opening. Initially, the isolation sleeve 120 and cluster sleeves (only on 160A shown) deploy downhole in a closed condition as shown in Figure 7A. The packing elements (114A-B; Fig. 5) engage the surrounding sidewall of the wellbore
10 to isolate a zone of the formation.

To begin activating the sleeves, operators drop a suitably sized ball 126 or other type of plug down the tubing string 110. Above the present arrangement on the string 110, the dropped ball 126 may pass any number of other arrangements of similar configured sleeves for other isolated zones. However, these other arrangements have
15 isolation sleeves configured to engage larger sized balls 126 or plugs. Therefore, the present ball 126 or plug passes through these uphole isolation sleeves without opening them.

In any event, the dropped ball 126 engages the isolation sleeve's seat 124 as shown in Figure 7A. The seated ball 126 now isolates any additional components
20 downhole from the present arrangement. At this point, operators pump fluid down the string's bore 112, and the pressure from the fluid acts against the seated ball 126. When the force reaches a configured limit, the holding ring 128, shear pins, or other affixing element break, and the fluid pressure pushes the seated ball 126 and sleeve 122 downhole as shown in Figure 7B. As it moves, the sleeve 122 reveals the external
25 ports 123 in the housing 121 so fluid can enter the well's annulus 14. The sleeve 122 reaches its limit, and a dog or lock ring 129 on the sleeve 122 engages in a profile in the housing 121.

The fluid pressure in the annulus 14 reaches the inlet port 167 on the cluster sleeve 160A. Pressure at the port 167 acts against the different sized faces or
30 shoulders that the port 167 has on its uphole and downhole ends. In particular, the downhole face or shoulder of the port 167 has a greater surface area than the uphole

face or shoulder. As the fluid pressure in the annulus 14 acts against these faces, it tends to push the external sleeve 164 downward relative to the internal sleeve 162 as the pressure differential between the wellbore annulus and pressure chamber 166 builds and acts against the sleeve 164. Eventually, the increasing pressure breaks the shear pins 168, as shown in Figure 7B. The fluid pressure forces the external sleeve 164 downward. This movement reveals the exit ports 163 for these cluster sleeves 160A-B so that fluid communicated down the tubing string 110 can exit and enter the annulus 14 at the locations of these ports 163.

In the present arrangements, the isolation sleeve 120 disposes downhole of the cluster sleeves 130/140/160 on the tubing string 110. In another arrangement shown in Figure 8A, the isolation sleeve 120 can be disposed uphole from the one or more cluster sleeves 180A-B in the isolated zone. When the isolation sleeve 120 seats the ball and opens, the isolated zone can be treated with the fluid pressure entering the annulus 14, while the seated ball prevents further fluid pressure to communicate down the tubing string 110. The cluster sleeve 180A-B can then be configured to open when a desired pressure in the wellbore annulus 14 is reached. At this point, fluid leaving the isolation sleeve 120 can re-enter the tubing string 110 via the one or more cluster sleeves 180A-B, which are now open and acting as a crossover below the isolation sleeve 120.

It is further conceivable that a given zone can have an isolation sleeve 120 disposed between uphole and downhole cluster sleeves 180A-B. As shown in Fig. 8B, the isolation sleeve 120 can be disposed between uphole and downhole cluster sleeves 180A-B in the isolated zone. When the isolation sleeve 120 seats the ball and opens, the isolated zone can be treated with the fluid pressure entering the annulus 14, while the seated ball prevents further fluid pressure to communicate down the tubing string 110. The uphole cluster sleeve 180A can be configured to open when a desired pressure in the wellbore annulus 14 is reached so more of the isolated zone can be treated.

At the same pressure or at a higher pressure, the downhole cluster sleeve 180B can be configured to open when a desired pressure in the wellbore annulus 14 is reached. At this point fluid leaving the isolation sleeve 120 can re-enter the tubing

string 110 via the downhole cluster sleeve 180B, which is now open and acting as a crossover. These and other combinations of isolation sleeves, cluster sleeves, packing elements, and pressure differentials according to the present disclosure may be advantageous for various reasons in a wellbore.

5 In addition to the above-arrangements, it will be appreciated with the benefit of the present disclosure that an isolated zone of a tubing string in a wellbore can have one or more cluster sleeves (140/160/180) disposed thereon along with more than one isolation sleeve (120) as well. Moreover, it will be appreciated with the benefit of the present disclosure that a tubing string (or an isolated section of a tubing string) in
10 a wellbore can have one or more cluster sleeves (140/160/180) disposed thereon without having an isolating sleeve (120). For example, the arrangements of cluster sleeves 130, 140, 160, and 180 in Figures 1, 2, 5, and 8A-8B may lack an isolating sleeve 120 disposed on the string 110. For such an arrangement of cluster sleeves 130, 140, 160, and 180 to open, fluid pressure is applied to the wellbore annulus by any
15 suitable technique available in the art (e.g., by using a mechanically shifted sliding sleeve or a ported housing, by pumping fluid pressure down the wellbore annulus, etc.). In other words, for example, the isolation sleeve 120 in any of Figures 1, 2, 5, and 8A-8B could be a mechanically shifted sliding sleeve, a ported housing, or the like. With the benefit of the present disclosure, it will be appreciated that the disclosed sliding
20 sleeves can be used in these and other arrangements.

 The foregoing description of preferred and other embodiments is not intended to limit or restrict the scope or applicability of the inventive concepts conceived of by the Applicants. As can be seen from the cluster sleeves disclosed above, the cluster sleeve includes a movable sleeve that can move from a closed condition to an
25 open condition relative to an outlet. The movable sleeve can be an internal sleeve or insert (e.g., 142; Fig. 3A) or an external sleeve (e.g., 164; Fig. 6A). This movable sleeve (142/162) is set to the closed condition and has a pressure chamber. In either case, the movable sleeve (142/162) moves from the closed condition to the open condition in response to a pressure differential between the wellbore annulus pressure
30 and the pressure chamber (and any shear pins or other retainers if applicable). With the sleeve moved open, fluid pressure can communicate from the tubing string to the

wellbore annulus through the outlet that had been previously covered by the movable sleeve. In general, each cluster sleeve 180 can be configured to open in response to a same or different pressure differential compared to the other cluster sleeves on the tubing string.

- 5 In exchange for disclosing the inventive concepts contained herein, the Applicants desire all patent rights afforded by the appended claims. Therefore, it is intended that the appended claims include all modifications and alterations to the full extent that they come within the scope of the following claims or the equivalents thereof.

WHAT IS CLAIMED IS:

1. A wellbore fluid treatment method, comprising:

deploying a plurality of sliding sleeves on a tubing string in a wellbore annulus, the sliding sleeves at least including a first sliding sleeve and at least one second sliding sleeve;

opening the first sliding sleeve to communicate fluid pressure from the tubing string to the wellbore annulus by deploying a first plug down the tubing string to the first sliding sleeve and applying fluid pressure in the tubing string against the first plug in the first sliding sleeve;

communicating the applied fluid pressure from the tubing string to the wellbore annulus through the open first sliding sleeve by applying the fluid pressure in the tubing string;

opening the at least one second sliding sleeve by applying the applied fluid pressure communicated in the wellbore annulus from the first sliding sleeve relative to a pressure chamber exposed externally on the at least one second sliding sleeve; and

communicating the applied fluid pressure from the tubing string to the wellbore annulus through the open at least one second sliding sleeve by applying the fluid pressure in the tubing string.

2. A wellbore fluid treatment method, comprising:

deploying a plurality of sliding sleeves on a tubing string in a wellbore annulus, the sliding sleeves at least including a first sliding sleeve and at least one second sliding sleeve;

seating a plug in the first sliding sleeve;

applying fluid pressure in the tubing string;

opening the first sliding sleeve with the applied fluid pressure applied against the seated plug in the first sliding sleeve;

communicating the applied fluid pressure to the wellbore annulus through the open first sliding sleeve by applying the fluid pressure in the tubing string;

applying the applied fluid pressure in the wellbore annulus communicated from the open first sliding sleeve relative to a pressure chamber exposed externally on the at least one second sliding sleeve;

opening the at least one second sliding sleeve with a pressure differential between the pressure chamber and the applied fluid pressure in the wellbore annulus; and

communicating the applied fluid pressure to the wellbore annulus through the open at least one sliding sleeve by applying the fluid pressure in the tubing string.

3. The method of claims 1 or 2, wherein deploying the plurality of sliding sleeves comprises:

isolating the wellbore annulus uphole and downhole of the plurality of sliding sleeves on the tubing string.

4. The method of claim 3, wherein isolating the wellbore annulus comprises engaging packing elements on the tubing string uphole and downhole of the sliding sleeves against a sidewall of the wellbore.

5. The method of any one of claims 1 to 4, wherein deploying the sliding sleeves comprises deploying the at least one second sliding sleeve uphole of the first sliding sleeve on the tubing string.

6. The method of any one of claims 1 to 5, wherein the first sliding sleeve comprises:

a movable sleeve being movable from a closed condition to an open condition relative to an outlet; and

a seat disposed on the movable sleeve and engaging with the first plug when deployed down the tubing string,

the movable sleeve moving to the open condition in response to the applied fluid pressure applied against the seated first plug.

7. The method of any one of claims 1 to 5, wherein opening the first sliding sleeve to communicate the applied fluid pressure from the tubing string with the wellbore annulus comprises:

engaging the deployed first plug on a seat of a movable sleeve of the first sliding sleeve; and

moving the movable sleeve open relative to an outlet of the first sliding sleeve with the applied fluid pressure applied against the seated first plug.

8. The method of any one of claims 1 to 7, wherein the at least one second sliding sleeve comprises:

a movable sleeve being movable from a closed condition to an open condition relative to an outlet, the movable sleeve moving from the closed condition to the open condition in response to a pressure differential between the applied fluid pressure in the wellbore annulus and the pressure chamber, the movable sleeve in the open condition permitting the applied fluid pressure from the tubing string to communicate to the wellbore annulus through the outlet.

9. The method of any one of claims 1 to 7, wherein opening the at least one second sliding sleeve comprises:

creating a pressure differential between the applied fluid pressure in wellbore annulus and the pressure chamber of a movable sleeve on the at least one second sliding sleeve; and

moving the movable sleeve open relative to an outlet on the at least one second sliding sleeve in response to the created pressure differential.

10. The method of claim 8 or 9, wherein to create the pressure differential, the method comprises applying the applied fluid pressure in the wellbore annulus against a shoulder on the movable sleeve to act against the pressure chamber, the shoulder exposed externally to the wellbore annulus.

11. The method of any one of claims 1 to 10, wherein deploying the sliding sleeves comprise deploying a third sliding sleeve and at least one fourth sliding sleeve uphole from the first sliding sleeve and the at least one second sliding sleeve.

12. The method of claim 11, wherein deploying the sliding sleeves comprises isolating the third sliding sleeve and the at least one fourth sliding sleeves from the first sliding sleeve and the at least one second sliding sleeve in the wellbore annulus.

13. The method of claim 11 or 12, wherein the method further comprises:

opening the third sliding sleeve to communicate fluid pressure from the tubing string to the wellbore annulus by deploying a second plug down the tubing string to the third sliding sleeve and applying fluid pressure in the tubing string against the second plug in the third sliding sleeve; and

opening the at least one fourth sliding sleeve by applying the applied fluid pressure in the wellbore annulus through the open third sliding sleeve relative to a pressure chamber exposed externally on the at least one fourth sliding sleeve.

14. The method of any one of claims 1 to 13, wherein the tubing string comprises a plurality of the at least one second sliding sleeves, each of the second sliding sleeves having a pressure chamber and each opening in response to a same or different pressure differential between the wellbore annulus and the pressure chamber.

15. A wellbore fluid treatment apparatus, comprising:

a first sliding sleeve disposing on a tubing string in a wellbore and opening in response to fluid pressure applied down the tubing string, the open first sliding sleeve communicating the applied fluid pressure from the tubing string to a wellbore annulus through a first outlet on the first sliding sleeve; and

a second sliding sleeve disposing on the tubing string in the wellbore and having a pressure chamber exposed externally to the wellbore annulus, the second sliding sleeve opening in response to a pressure differential between the pressure chamber and the applied fluid pressure communicated in the wellbore annulus by the first sliding sleeve, the open second sliding sleeve communicating the applied fluid pressure from the tubing string to the wellbore annulus through a second outlet on the second sliding sleeve.

16. The apparatus of claim 15, further comprising at least one packing element disposing on the tubing string in the wellbore, the at least one packing element

isolating the wellbore annulus around the first and second sliding sleeves from other portions of the wellbore.

17. The apparatus of claim 15 or 16, wherein the first sliding sleeve comprises:

a movable sleeve being movable from a closed condition to an open condition relative to the first outlet; and

a seat disposed on the movable sleeve and engaging with a plug when deployed down the tubing string,

the movable sleeve moving to the open condition in response to the applied fluid pressure applied against the seated plug.

18. The apparatus of claim 15, 16 or 17, wherein the second sliding sleeve disposes uphole of the first sliding sleeve on the tubing string.

19. The apparatus of any one of claims 15 to 18, wherein the second sliding sleeve comprises:

a movable sleeve being movable from a closed condition to an open condition relative to the second outlet, the movable sleeve moving from the closed condition to the open condition in response to the pressure differential between the applied fluid pressure in the wellbore annulus and the pressure chamber, the movable sleeve in the open condition permitting the applied fluid pressure from the tubing string to communicate to the wellbore annulus through the second outlet.

20. The apparatus of claim 19, wherein the pressure chamber is defined between the movable sleeve and a housing portion of the at least one second sliding sleeve.

21. The apparatus of claim 19 or 20, wherein the applied fluid pressure in the wellbore annulus acts against the movable sleeve.

22. The apparatus of claim 19, 20 or 21, wherein:
the movable sleeve comprises an internal sleeve movably disposed in a bore of a housing of the second sliding sleeve, the housing defining the second outlet.

23. The apparatus of claim 19, 20 or 21, wherein the movable sleeve comprises an external sleeve movably disposed on a housing of the second sliding sleeve, the housing defining the second outlet.

24. The apparatus of claim 22 or 23, wherein the movable sleeve comprises a shoulder exposed externally to the wellbore annulus against which the fluid pressure in the wellbore annulus is applied.

25. The apparatus of any one of claims 15 to 24, further comprising at least one third sliding sleeve disposing on the tubing string in the wellbore and having another pressure chamber exposed externally to the wellbore annulus, the at least one third sliding sleeve opening in response to a same or different pressure differential between the applied fluid pressure in the wellbore annulus and the pressure chamber.

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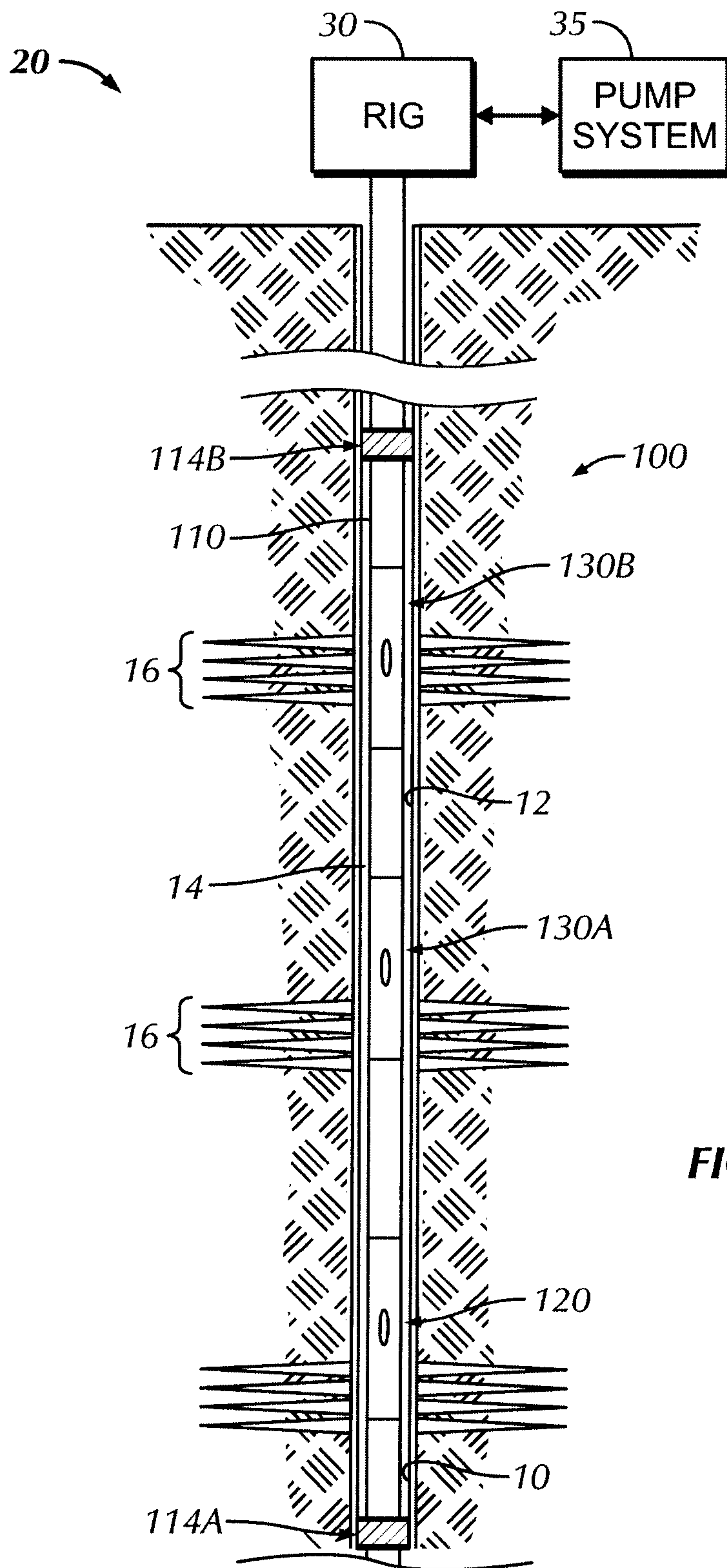


FIG. 1

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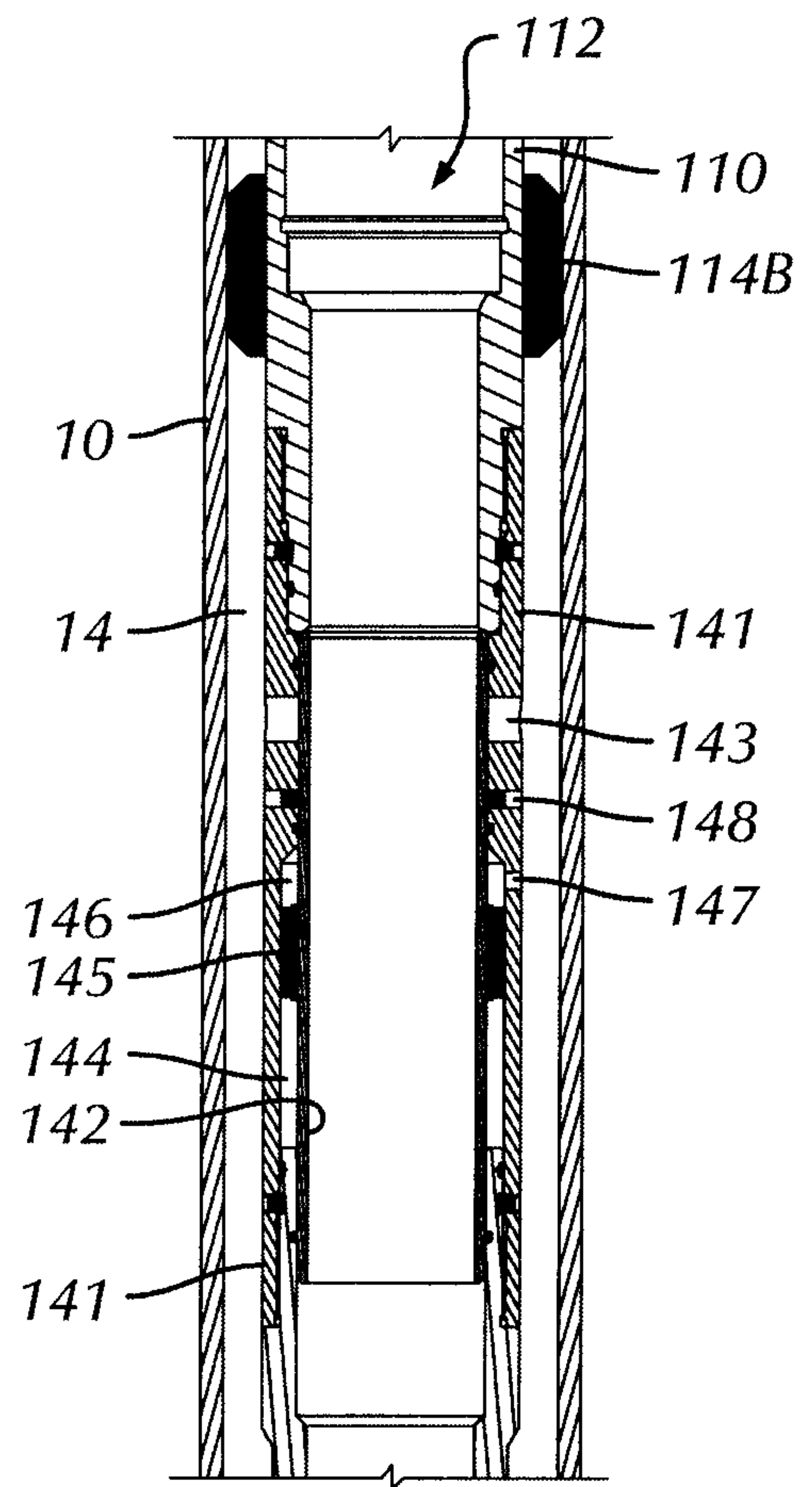
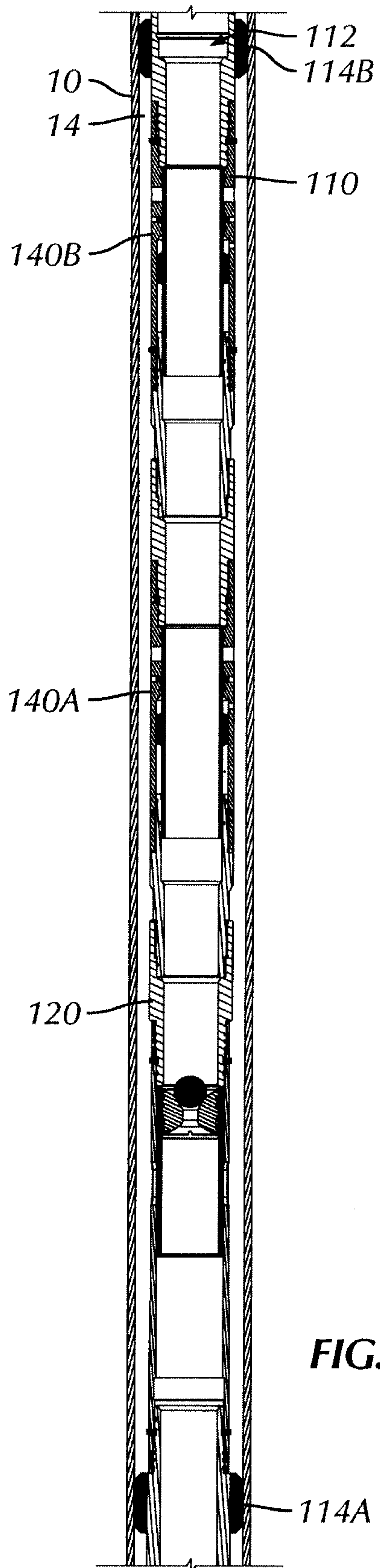


FIG. 3A

FIG. 2

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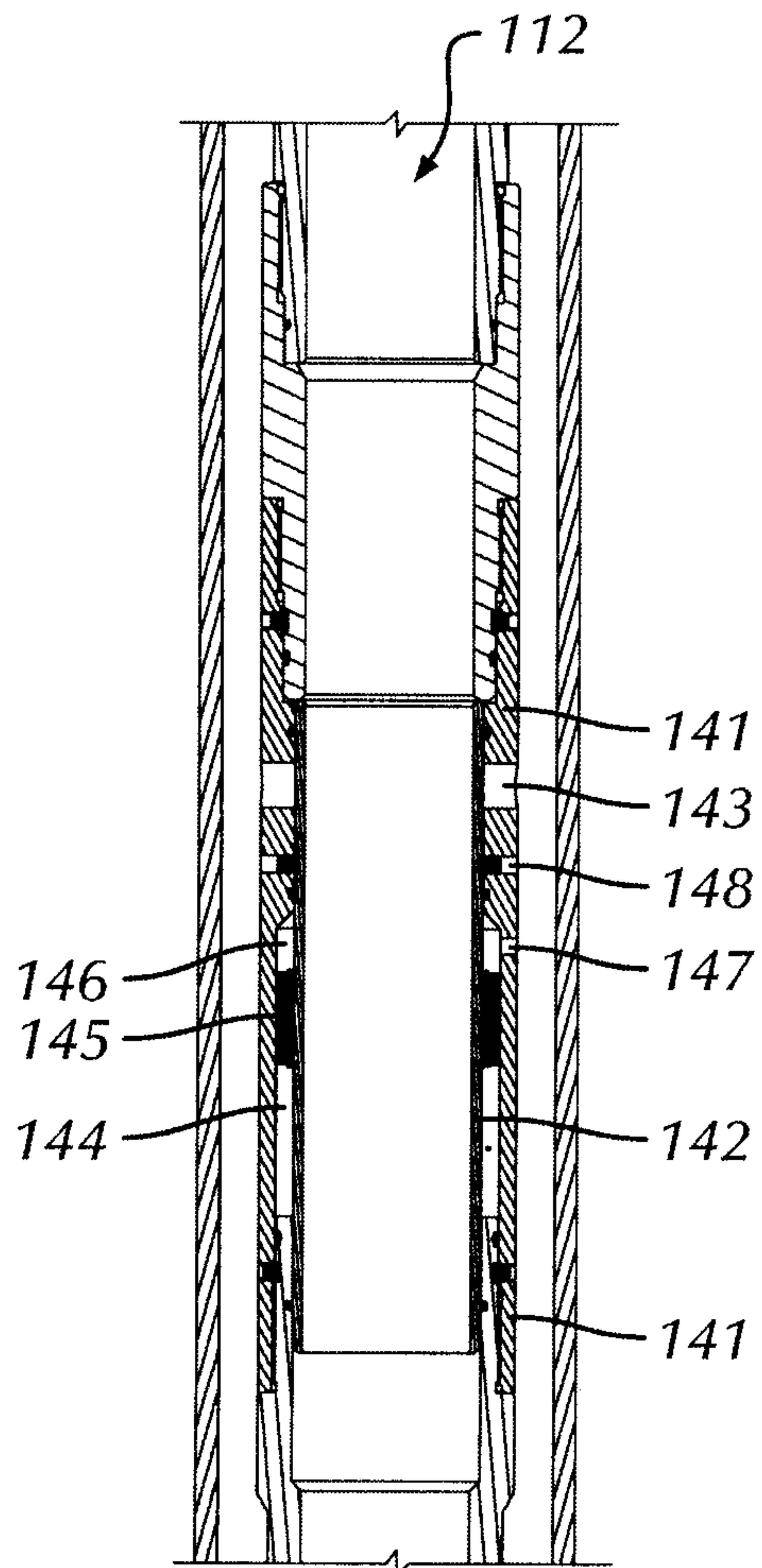


FIG. 3B

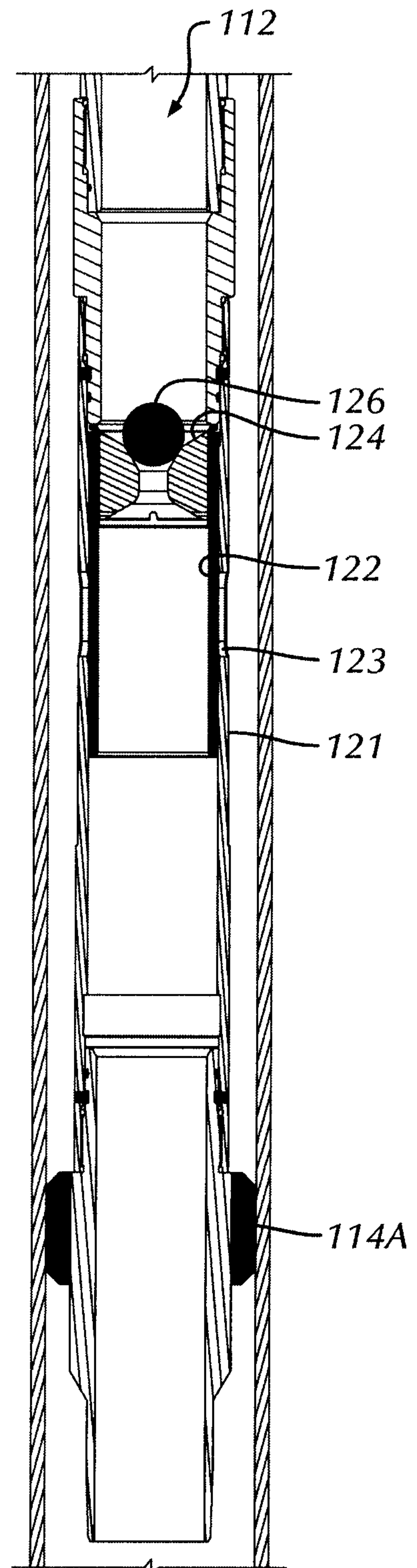


FIG. 3C

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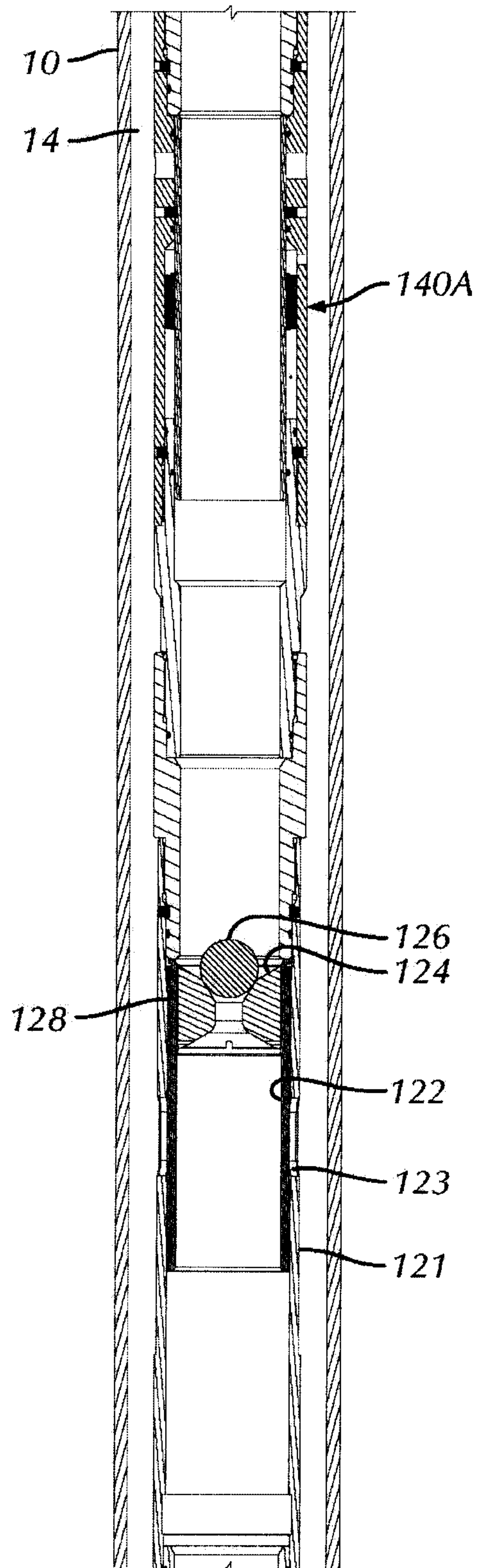


FIG. 4A

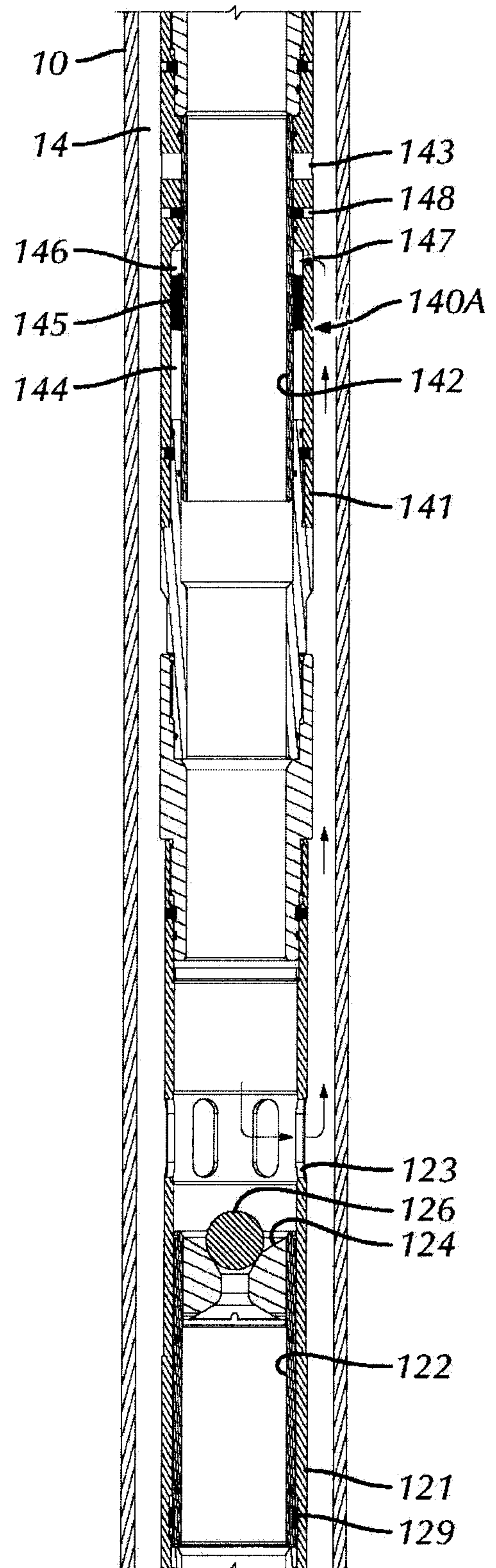


FIG. 4B

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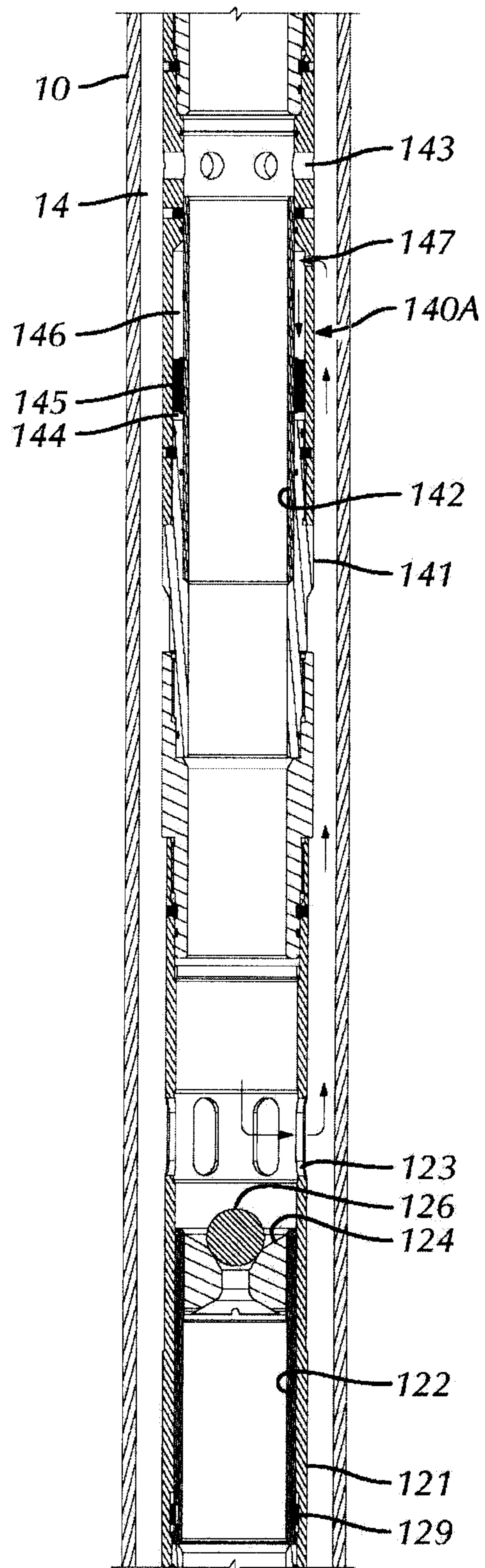


FIG. 4C

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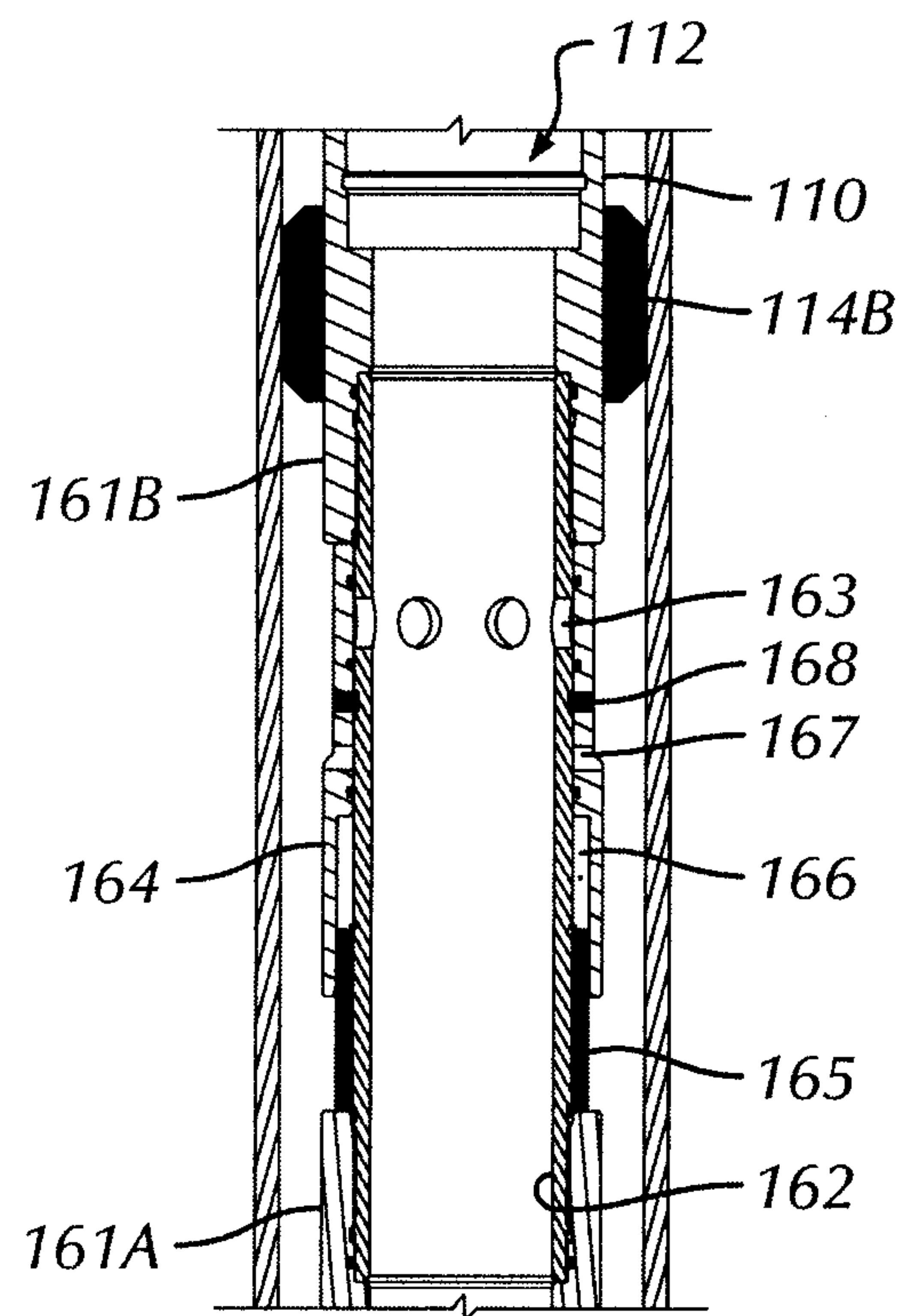
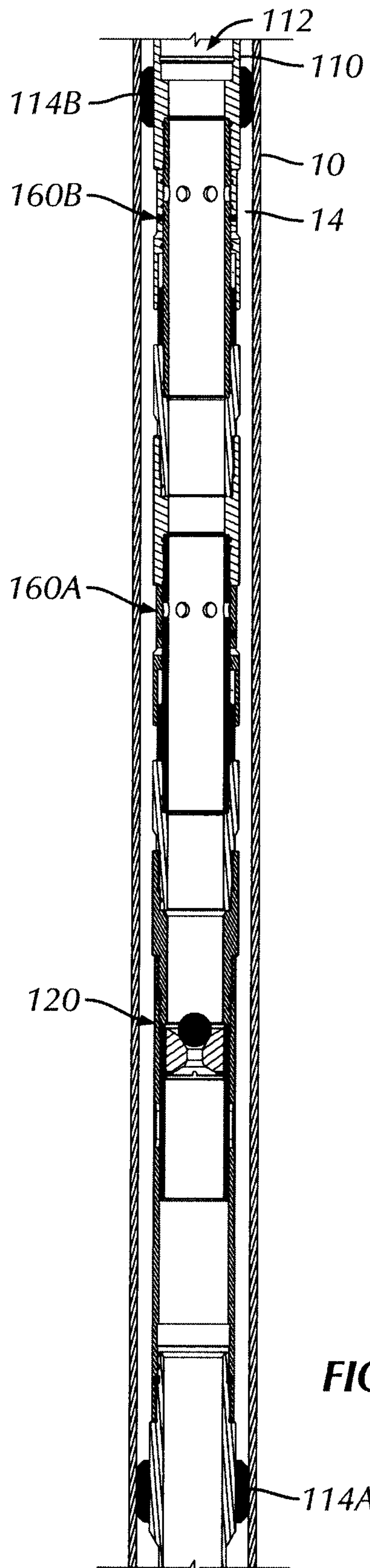


FIG. 6A

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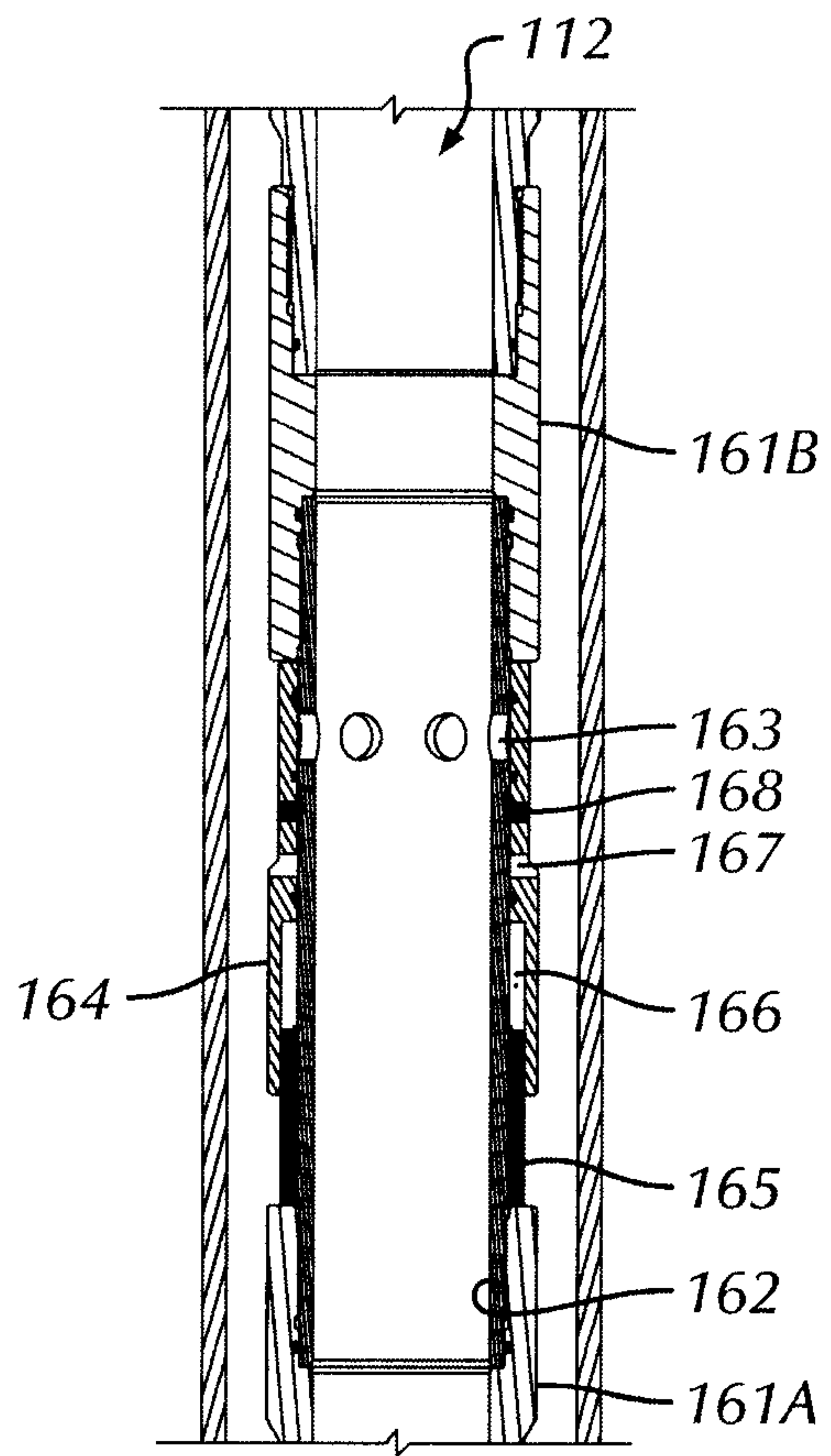


FIG. 6B

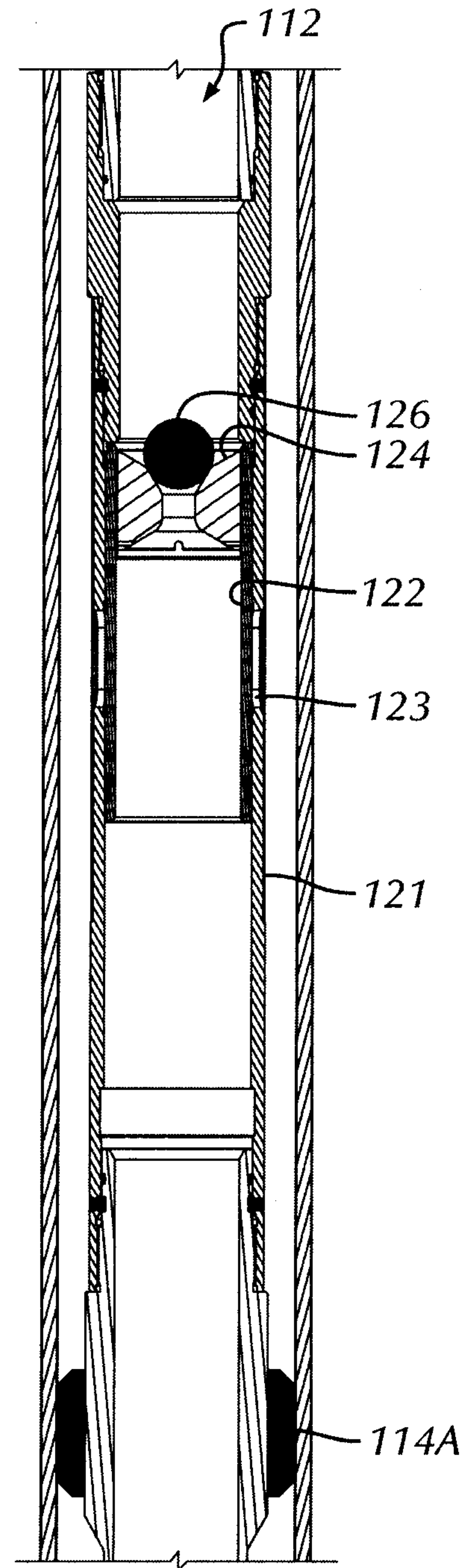


FIG. 6C

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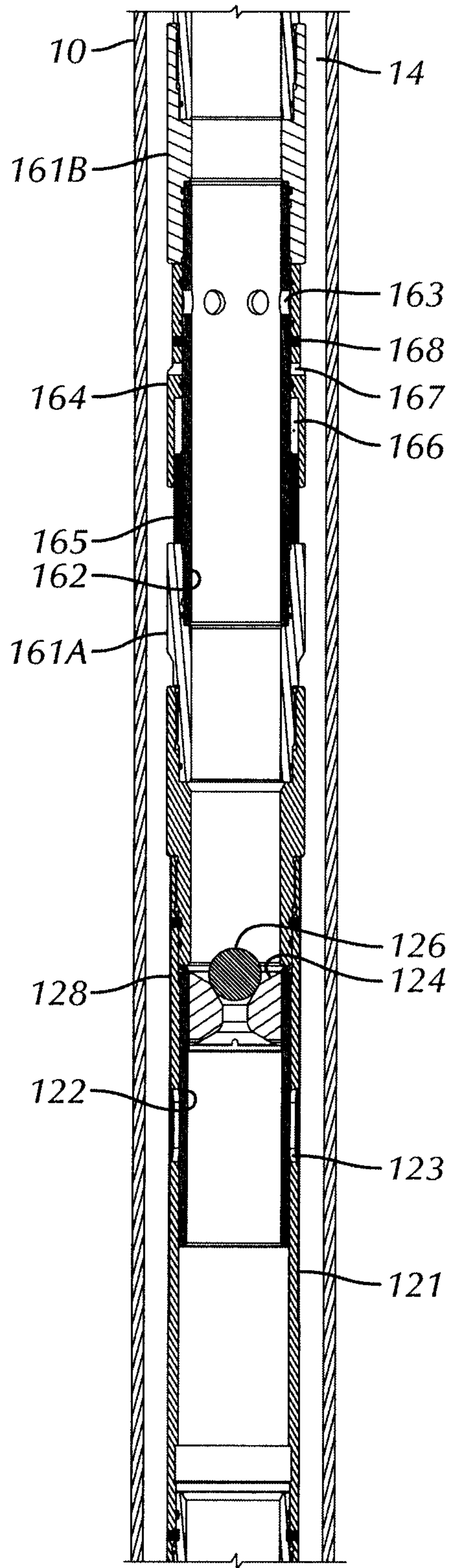


FIG. 7A

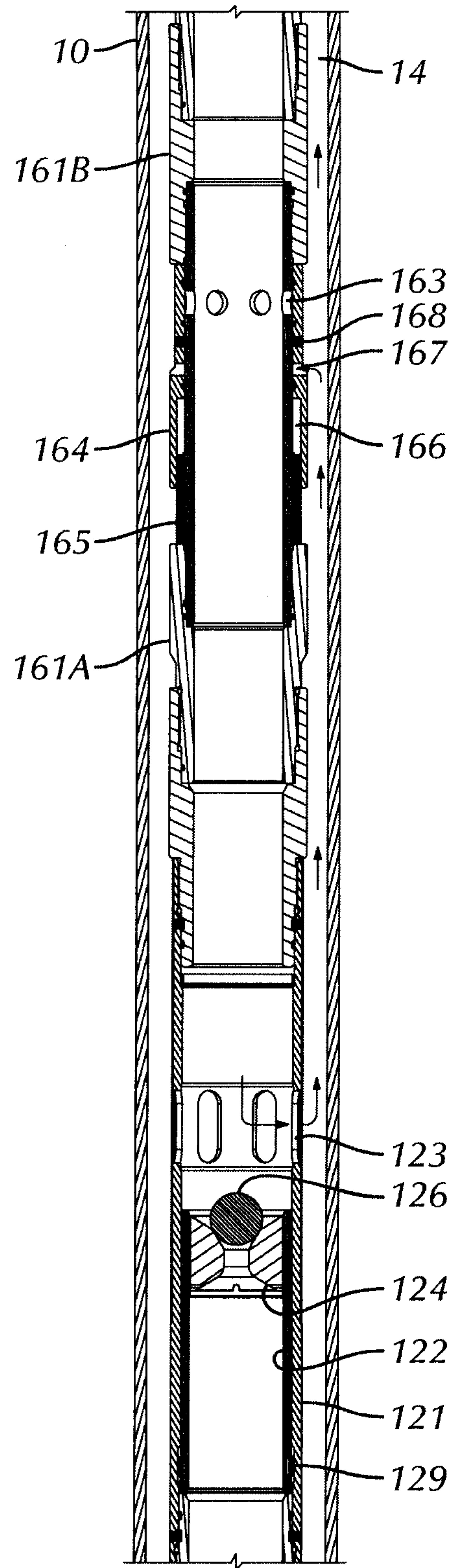


FIG. 7B

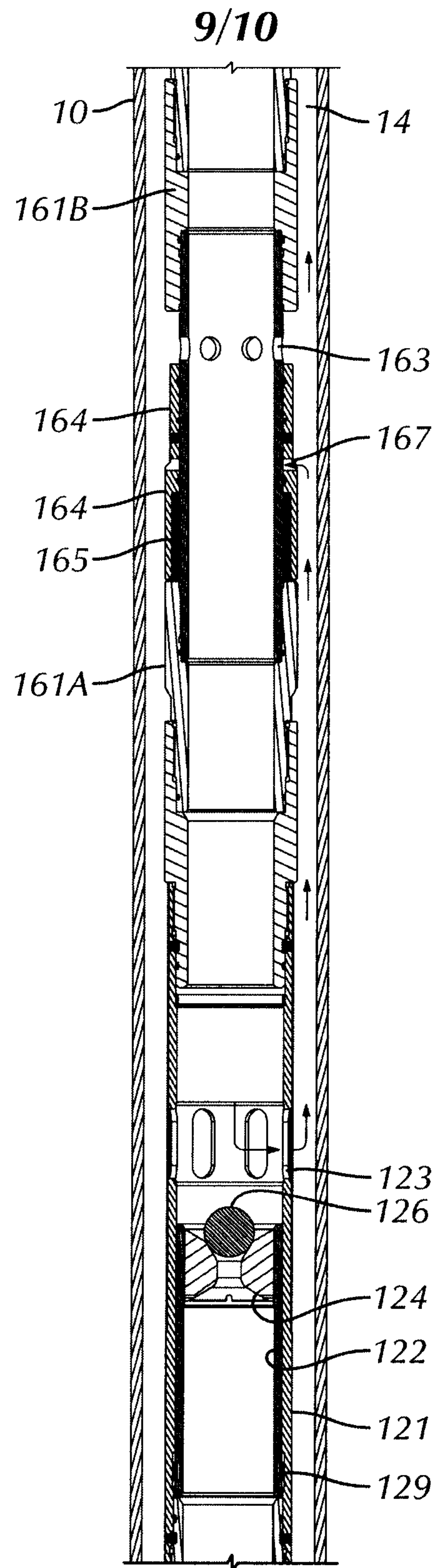
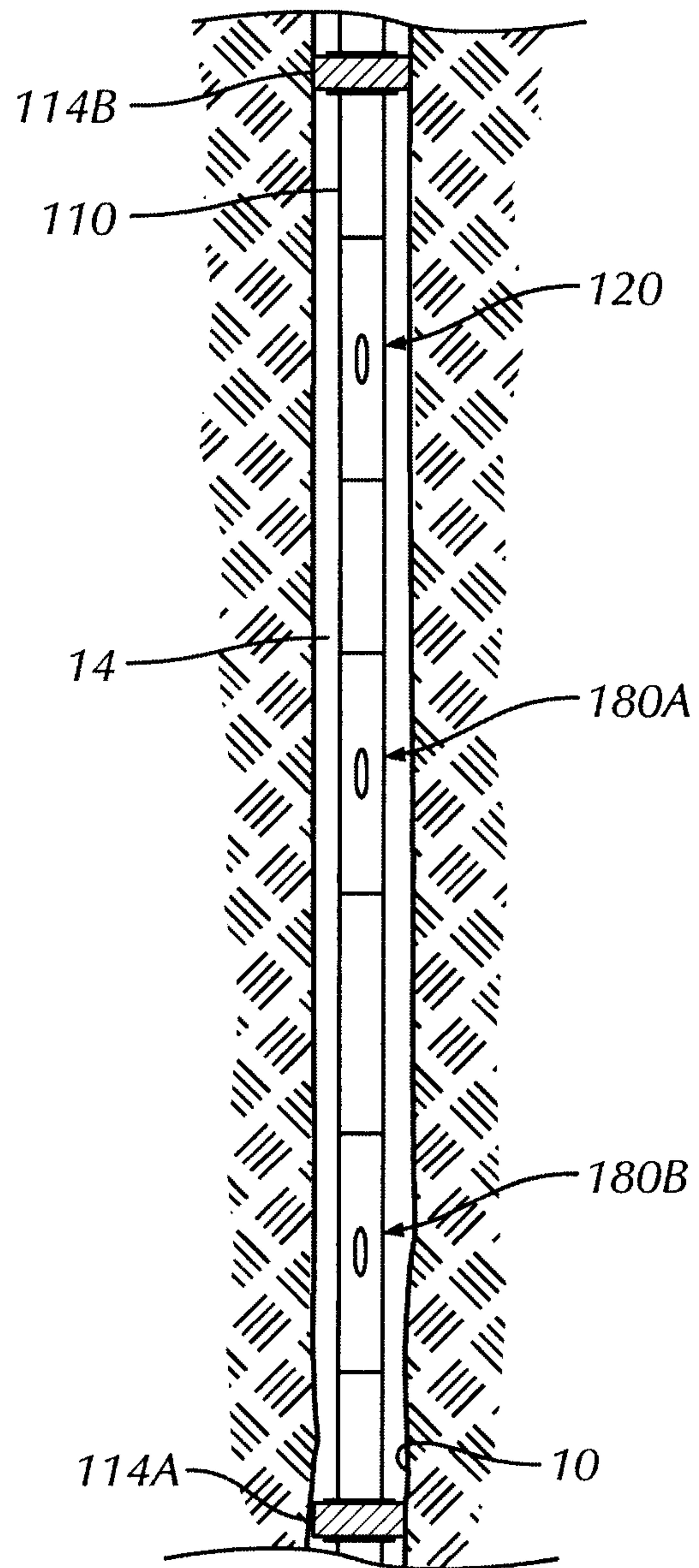
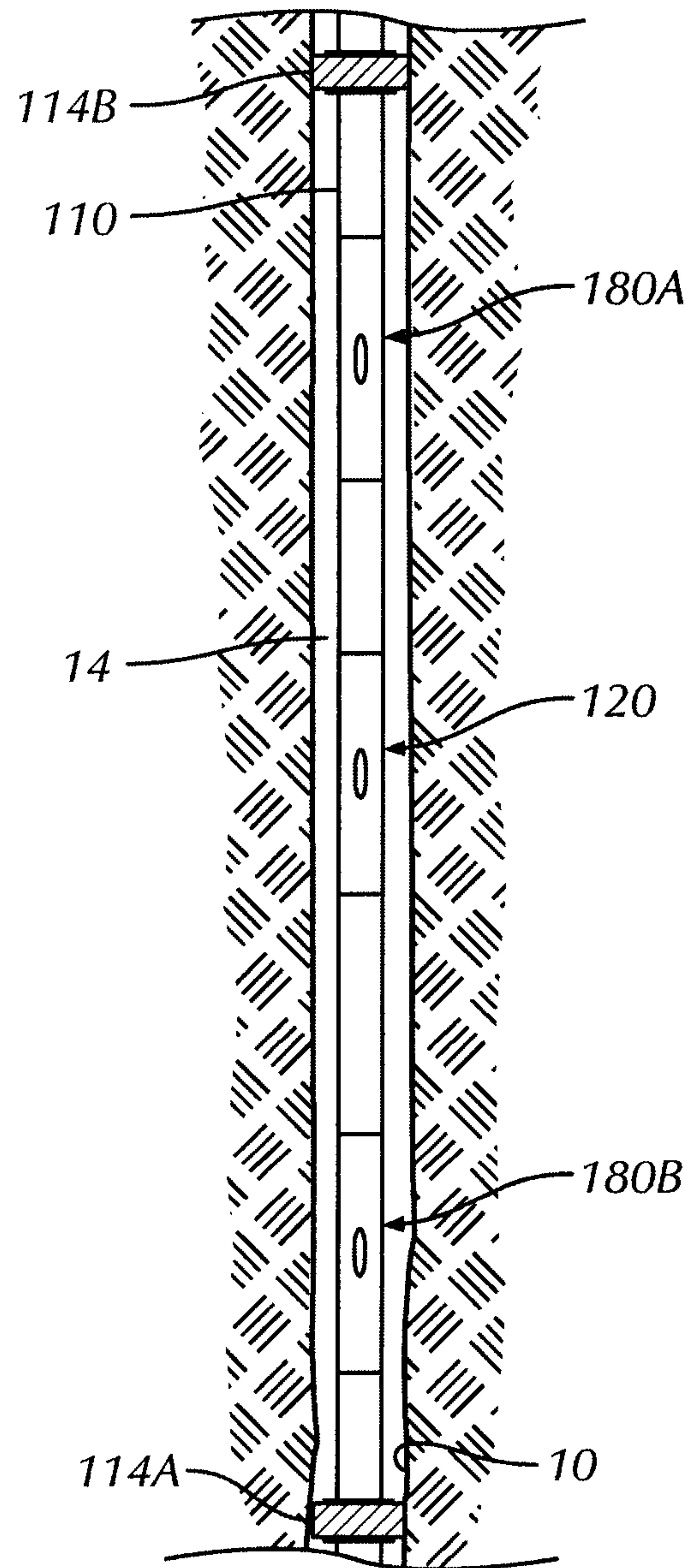


FIG. 7C

10/10**FIG. 8A****FIG. 8B**

