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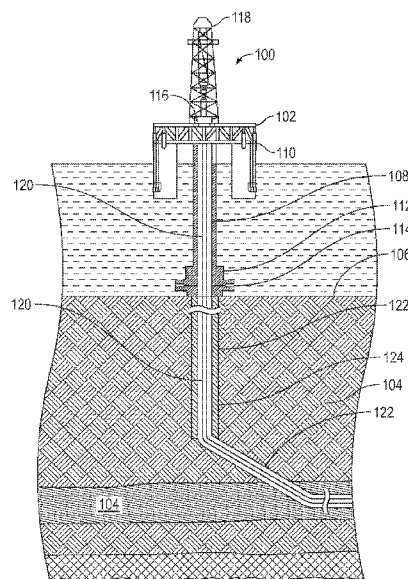


FIG. 1

(57) Abstract: Disclosed herein are various embodiments of a downhole system having a millable joint with a first portion shaped to extend into a main wellbore and a second portion shaped to extend into a lateral wellbore, a cutting guide at least partially disposable within the millable joint; and a cutting assembly configured to move alongside the guide until engaging with a sidewall of the millable joint. Further disclosed are various embodiments for methods of operating a downhole system having a millable joint. Further disclosed are various embodiments for a downhole deflector assembly, having a deflector securable within a main wellbore wherein an uphole end of the deflector comprises an angled face configured to direct one or more tubulars from the main bore to a lateral bore and a whipstock insert attachment detachably securable to the deflector.



GUIDED MAINBORE MILL THROUGH MULTILATERAL JUNCTION

BACKGROUND

[0001] It is known in the art of constructing subterranean wells to form a main bore into the earth and subsequently form one or more bores extending laterally therefrom. Generally, the main bore is drilled and completed after which, a tool known as a whipstock is positioned in the parent bore casing. The whipstock is specially configured to deflect cutting tools (e.g., milling bits and drill bits) in a desired direction for forming a lateral bore. A cutting device, such as a drill bit or a mill, is lowered into the parent bore suspended from drill pipe and is radially deflected by the whipstock to create a window in the wellbore wall of the parent bore from which an additional borehole may be extended using directional drilling techniques.

BRIEF DESCRIPTION OF THE DRAWINGS

[0002] These drawings illustrate certain aspects of some of the embodiments of the present disclosure and should not be used to limit or define the method.

[0003] FIG. 1 illustrates a schematic view of a well system that may employ the principles of the present disclosure.

[0004] FIG. 2 illustrates a cross-sectional side view of a well system with production tubulars and equipment disposed within a main bore with upper completion removed and an isolation device installed, in accordance with some embodiments of the present disclosure.

[0005] FIG. 3 illustrates a cross-sectional side view of a well system with a multi-lateral anchor installation in a main bore, in accordance with some embodiments of the present disclosure.

[0006] FIG. 4 illustrates a cross-sectional side view of a well system with a base deflector and whipstock insert attachment installation in a main bore, in accordance with some embodiments of the present disclosure.

[0007] FIG. 5 illustrates a cross-sectional side view of a well system with a cutting/milling assembly aligned with a whipstock insert attachment to cut/mill a window through a main bore, in accordance with some embodiments of the present disclosure.

[0008] FIG. 6 illustrates a cross-sectional side view of a well system with a cutting/milling assembly extending a casing window for a first lateral bore from a main bore, in accordance with some embodiments of the present disclosure.

[0009] FIG. 7 illustrates a cross-sectional side view of a well system with a drilling assembly extending a portion of a lateral bore from a main bore, in accordance with some embodiments of the present disclosure.

[0010] FIG. 8 illustrates a cross-sectional side view of a well system with a hydraulic deployment and retrieval tool engaged into the whipstock insert attachment, in accordance with some embodiments of the present disclosure.

[0011] FIG. 9 illustrates a cross-sectional side view of a well system with a millable joint disposed at the junction of the main wellbore and the lateral wellbore and first lateral liner disposed within the lateral wellbore, in accordance with some embodiments of the present disclosure.

[0012] FIG. 10 illustrates a cross-sectional side view of a well system with a drilling assembly extending a portion of a lateral wellbore main wellbore, in accordance with some embodiments of the present disclosure.

[0013] FIG. 11 illustrates a cross-sectional side view of a well system with a completion installation in a lateral wellbore extending from a main wellbore, in accordance with some embodiments of the present disclosure.

[0014] FIG. 12 illustrates a cross-sectional side view of a well system with a cutting assembly disposed within a cutting guide installed within a main bore and a lateral bore, in accordance with some embodiments of the present disclosure.

[0015] FIG. 13 illustrates a cross-sectional side view of a well system with a cutting/milling assembly creating a passageway via a cutting guide into the millable joint disposed within a main bore, in accordance with some embodiments of the present disclosure.

[0016] FIG. 14 illustrates a cross-sectional side view of a well system with a passageway exposed through a millable joint, in accordance with some embodiments of the present disclosure.

[0017] FIG. 15 illustrates a cross-sectional side view of a well system with completion system disposed within a main bore, in accordance with some embodiments of the present disclosure.

[0018] FIG. 16 illustrates a cross-sectional side view of a well system with a dual leg junction completion system disposed within a main bore and a lateral bore, in accordance with some embodiments of the present disclosure.

DETAILED DESCRIPTION

[0019] The present invention relates generally to the art of completing subterranean wells having a lateral branch with two or more branch sections extending from a common bore section (e.g., “a main bore”). The two or more branch sections include an initial first branch which extends from the common bore in any direction (e.g., vertical, horizontal, slant-hole, or combinations thereof), along with at least one additional second branch which may extend from the first branch in any direction (e.g., vertical, horizontal, slant-hole, or combinations thereof). In some examples, a common bore and a main wellbore, extending directly therefrom, may be constructed in a subterranean formation to form a main wellbore. The construction process may involve any drilling and completion technique as would be beneficial to the construction of the well. Subsequently, an additional one or more branches may be added to the main wellbore which gain the benefit of the previously constructed main bore.

[0020] The term “lateral” wellbore is used herein to designate a wellbore that is drilled outwardly from its intersection with a main wellbore such that the lateral wellbore diverges from the main wellbore following a different well path to the main wellbore. Moreover, once the lateral wellbore has been lined the lateral wellbore may be extended with another lateral wellbore section drilled outwardly therefrom.

[0021] In some examples, both the main wellbore and the lateral wellbore may extend along a lateral trajectory, but may be displaced by a vertical distance, azimuth, or a combination thereof such that the main wellbore and lateral wellbore intersect different volumes of the subterranean formation. When at least one lateral wellbore is extended from the main bore and completed, production or injection operations may commence such that both the main wellbore and the at least one lateral wellbore both produce formation fluids and/or gases which may be conducted through the main bore, or a production or injection tubular within the main bore, to a surface location.

[0022] In some examples, the main wellbore may be utilized for formation fluid/gas extraction/injection operations (e.g., “production operations”) prior to the addition of the one or

more lateral wellbores. In such examples, the process of constructing and preparing the one or more lateral wellbores for production operations may be referred to as a “reentry operation,” since procedures which require reentering the well are going to be performed. While re-entry operations have the potential to reduce the consumption of materials and time by utilizing an existing wellbore to access greater coverage of the subterranean formation, the reentry operations are not without risk. In some scenarios, reentry operations may cause damage to either the main bore or main wellbore such that the well is not functional for its intended purposes and must be abandoned. The systems and methods herein reduce the time required to perform the re-entry operations while reducing the risk of damage to the original wellbore system (e.g., main bore).

[0023] FIG. 1 is a schematic view of a well system that could be used with any of the embodiments herein. As illustrated, the well system may comprise an offshore oil and gas system 100. The offshore oil and gas system 100 includes a platform 102, which may be a semi-submersible, rig or platform, positioned over a subterranean formation 104, containing hydrocarbons, located below the sea floor 106. A subsea conduit 108 (ex. riser) extends from the deck 110 of the platform 102 to a wellhead installation 112 including one or more blowout preventers 114. The platform 102 has a hoisting apparatus 116 and a derrick 118 for raising and lowering pipe strings, such as a drill string 120. Although the platform 102 shown on FIG. 1 illustrates as a semi-submersible offshore oil and gas platform, the scope of this disclosure is not thereby limited. The teachings of this disclosure may also be applied to other types of offshore oil and gas systems or land-based oil and gas systems.

[0024] As shown, a main wellbore 122 has been drilled through the various earth strata, including the subterranean formation 104. The term “main wellbore” is used herein to designate a borehole from which another wellbore is drilled. A casing string 124 may provide support against collapse of the subterranean formation 104 surrounding main wellbore 122. In some examples, the casing string 124 may be at least partially cemented within main wellbore 122. The term “casing” is used herein to designate a tubular string used to line a wellbore. Casing may actually be of the type known to those skilled in the art as “liner” and may be made of any material, such as steel or composite material and may be segmented or continuous, such as coiled tubing.

[0025] FIG. 2 illustrates a cross-sectional side view of the main wellbore 122 once it has turned to run horizontally, where the existing upper completion components have been removed from the

main wellbore 122. Thus as depicted, the tubulars 198 have been removed as well as the completion components down to a predetermined depth. Prior to this operation an isolation device 195 is preferably set into the liner hanger assembly 180 on a packer 185 but it should be noted that any isolation device can be used and it would preferably be set in the main wellbore 122 downhole from an isolation point where the lateral wellbore will be constructed. Whatever isolation device is used, it should isolate the main wellbore 122 to prevent any losses or influx from any source of inflow that occur below the isolation point.

[0026] For example, the main wellbore 122 may have a liner secured to the wellbore wall with a liner hanger assembly 180 which includes at least one annular seal, in this embodiment a packer 185 is used. However, the one or more tubulars 198 may alternatively include casing or any other suitable tubulars which may be secured to the wellbore wall by known methods. The tubulars 198 may include perforations 190 (ex. holes or slots or some combination of both) such that formations fluids may pass from the reservoir (e.g., subterranean formation 104) to an internal portion of the tubulars 198 via the perforations 190. An uphole end of the liner disposed above the liner hanger assembly 180, may be exposed to create a surface on which various wellbore equipment may wash-over, sting into, or abut. As depicted, the well system may include an isolation device 195 disposed within the liner to provide for flow isolation up the inside of the liner which may be desirable during re-entry operations.

[0027] FIG. 3 illustrates a cross-sectional side view of a multi-lateral anchor assembly 200 which may be used to facilitate re-entry work. The multi-lateral anchor assembly 200 may include an anchor 205 disposed at one end and an overshot stinger 210 at the opposing end of the multi-lateral anchor assembly 200. Further, a central bore may extend through the multi-lateral anchor assembly 200 such that fluid can pass longitudinally from one end (e.g., the anchor end) to the other (e.g., the overshot stinger end) of the multi-lateral anchor assembly 200. Moreover, the multi-lateral anchor assembly 200 may be made up on the rig floor after which a deployment device 220 including a measurement while drilling device (“MWD”) 215 may be stung into at least a portion of the bored-out section of the multi-lateral anchor assembly 200.

[0028] The deployment device 220 may include a retractable extruding portion 230 (ex. collapsible collet or latch) which matches to a collet profile 225 disposed on a surface of the inner diameter of the multi-lateral anchor assembly 200. The deployment device 220 may be detachably

engageable with the multi-lateral anchor assembly 200 such that engaging the multi-lateral anchor assembly to a deployment device 220 further disposed on a work string or other tubular may allow for the multi-lateral anchor assembly 200 to be relayed to a desired position in a subterranean wellbore. The installation configuration may provide a seal with the cut tubing portion exposed above the tubular hanger assembly with an overshot stinger 210 such that the outer diameter of the exposed cut tubing is encased within the inner diameter of the overshot stinger 210. It should be noted that in some embodiments the overshot stinger could be non-sealing, as the anchor can provide the annular seal after it's oriented and activated at the correct depth.

[0029] Once the multi-lateral anchor assembly 200 is placed in the proper position, an annular seal assembly may be disposed on the outer diameter of the multi-lateral anchor assembly 200 and may be manipulated to engage with the inner diameter of the main bore wall. Once the installation is complete, retractable extruding portion 230 of the deployment device may be manipulated to disengage from the collet profile 225 disposed within the multi-lateral anchor assembly 200 further allowing the deployment device 220 to move independent of the multi-lateral anchor assembly 200. Upon disengagement between the deployment device 220 and the multi-lateral anchor assembly 200, the work string along with the deployment device 220 may be tripped out of hole or pulled out of hole to prepare for the next portion of the operation. As depicted, the up-hole facing portion of the multi-lateral anchor assembly 200 may exhibit a geometric profile shaped to mate with other equipment or tools to ensure correct downhole alignment. In some embodiment, what may be referred to as a "muleshoe," profile may be used, where the face of the up-hole facing surface of the multi-lateral anchor assembly 200 is cut at an angle.

[0030] FIG. 4 illustrates a cross-sectional side view of the deflector assembly 250 which may include a retrievable whipstock insert attachment 305 secured or latched into the multi-lateral anchor assembly. A hydraulic deployment and retrieval tool (HDRT) 290 may be detachably secured to the deflector assembly 250 such that, in an engaged position, direct contact occurs between an inner surface of the whipstock insert attachment 305 and an exterior of the HDRT 290. Although it should be noted that other embodiments may run and install the exemplary systems herein with the milling string.

[0031] In particular, the whipstock insert attachment 305 may include at least one slot or feature formed in the inner surface of the whipstock insert attachment 305. Further, the HDRT 290 may

include at least one locking feature 315 (e.g., radial piston, etc.) configured to expand into the at least one slot or feature of the whipstock insert attachment 305 in the engaged position. Contact between the locking feature 315 and at least one slot or feature may secure the HDRT 290 to the deflector assembly 250. As such, the deflector assembly 250 may be run-in-hole via the HDRT 290 and installed in the multi-lateral anchor assembly 200 as illustrated. In particular, a portion of the deflector assembly 250 may be inserted into at least a portion of the bored-out section of the multi-lateral anchor assembly 200. Once the deflector assembly is secured or latched in the proper position in the wellbore, the HDRT 290 may disengage from the deflector assembly 250 (e.g., the locking feature 315 may retract to decouple the HDRT 290 from the whipstock insert attachment 305). Further, the HDRT 290 may be secured to a lower end of the work string such that when the HDRT 290 is disengaged the HDRT 290 may be removed from the wellbore by tripping the work string out of the well.

[0032] As depicted, the deflector assembly 250 may include a whipstock insert attachment 305 detachably securable to the deflector assembly 250. As illustrated, a portion of the whipstock insert attachment 305 may be inserted into or securably nested within the deflector assembly 250. Further, the deflector assembly 250 may include at least one slot or feature formed in the inner surface of the deflector assembly 250, and the whipstock insert attachment 305 may include at least one locking feature 318 (e.g., radial piston, shear pin etc.) configured to lock the whipstock insert attachment to the deflector assembly 250 in the engaged position. Alternatively, shear pins and/or other fasteners may be used to secure the whipstock insert attachment 305 to the deflector assembly 250.

[0033] Moreover, in the installed configuration, the whipstock insert attachment 305 should be at least partially nested within the deflector assembly 250, which should be at least partially nested within the multi-lateral anchor assembly 200. The foregoing assembly is preferably installed in the wellbore such that an end of the whipstock insert attachment 305 is disposed at the uphole end of the installation configuration while an end of the multi-lateral anchor assembly 200 is disposed at the downhole end of the installation configuration. The deflector assembly 250 may include an external seal assembly 320 on an outer portion of a body of the deflector assembly 250, an alignment key 325 on the outer portion of the deflector assembly 250, a whipstock bore (e.g., bored-out section) which traverses the inner body of the deflector assembly 250, and an angled

face on at least one end of the body of the deflector assembly 250. The external seal assembly 320 of the deflector assembly 250 may be capable of sealing against the inner surface of the multi-lateral anchor assembly 200. The alignment key 325 may be capable of aligning and constricting the deflector assembly 250 and the whipstock insert attachment 305 (e.g., deflector assembly) to orient the angled face of the deflector assembly 250 and whipstock insert attachment 305 according to a preferred orientation conducive to forming a lateral leg of a preferred trajectory. In some examples, the whipstock bore of the deflector assembly 250 may be capable of conducting fluids along the longitudinal length of the deflector assembly 250.

[0034] Moreover, as illustrated, the angled whipstock face 335 (e.g., angled deflector face and/or angled whipstock face) on the at least one end of the body of the deflector assembly 250 may be oriented in the uphole direction when installed in the wellbore. The angled deflector face 335 may be angled or slanted with respect to the wellbore and its central axis. Further, a central bore of the deflector assembly 250 may extend through the angled deflector face 335. The central bore at the angled deflector face 335 may comprise a sufficient diameter to receive a portion of the whipstock insert attachment 305, such that the whipstock insert attachment 305 may be received in the deflector assembly 250. Additionally, the whipstock insert attachment 305 may include an angled whipstock face 335 of an uphole end of the whipstock insert attachment 305 that may be angled and/or oriented to provide a ramp to redirect a cutting assembly 400 away from the main bore for forming the second lateral bore, as set forth in greater detail below. The angled whipstock face 335 of the whipstock insert attachment 305 may be installed in an up-hole facing direction. Further, a portion of the uphole end of the whipstock insert attachment 305, opposite the angled whipstock face 335, may at least partially cover an uphole facing portion of the deflector assembly 250, which may protect the angled deflector face 335 during drilling operations of the lateral bore.

[0035] FIG. 5 illustrates a cross-sectional side view of a well system with a cutting assembly 400 engaging the angled whipstock face 335 of the whipstock insert attachment 305. As illustrated, the angled whipstock face 335 may guide the cutting assembly 400 to deviate from traveling along the lateral wellbore 128 and to cut a window through a sidewall of the main wellbore 122 to form a lateral wellbore 128. Moreover, the cutting assembly 400 may be tripped-in-hole (“TIH”) and aligned with the angled whipstock face 335 of the whipstock insert attachment 305. The cutting assembly 400 may include any cutting devices capable of traversing the barrier formed by the

previous completion equipment (e.g., casing, liners, cementing materials) disposed within the main wellbore or lateral wellbore 128. In some examples, the cutting devices may include chemical cutting devices, plasma cutting devices, abrasion cutting devices, hydraulic cutting devices, drill bits, milling assemblies, or other mechanical cutting assemblies. Further, as set forth above, the angled face of the whipstock insert attachment 305 may function to direct the cutting assembly 400 along a desired trajectory to guide the cutting assembly 400 through the wellbore barrier wall and into the subterranean formation. In some examples, the process of traversing the wellbore barrier wall may be referred to as “cutting a window,” or “milling a window.”

[0036] In some examples, the deflector assembly 250 may be run-in-hole via the cutting assembly 400. The cutting assembly 400 may be detachably secured to the whipstock insert attachment 305 of the deflector assembly 250 by a shear pin, shear bolt, or other suitable fastener. Once the deflector assembly 250 is relayed downhole, it may be latched into the anchor portion (e.g., uphole-facing portion) of the multi-lateral anchor assembly 200. In particular, a portion of the deflector assembly 250 may be inserted into at least a portion of the bored-out section of the multi-lateral anchor assembly 200. Once the deflector assembly 250 is secured in the proper position in the wellbore, a certain amount of over-pull may be exerted on the work string to shear the shear pin or other suitable fastener securing the cutting assembly 400 to the deflector assembly 250. Once the shear pin or other suitable fastener is sheared, the cutting assembly 400 may disengage from the whipstock insert attachment 305 and therefore disengage from the deflector assembly 250 after which cutting operations may commence.

[0037] FIG. 6 illustrates a cross-sectional side view of a well system with a cutting assembly 400 milling / drilling a portion of a lateral wellbore 128. As depicted, the cutting assembly 400 may traverse the barrier provided by the previous completion equipment disposed the lateral wellbore 128 to form a casing window. The lateral bore (e.g., branch section) may be initiated from the casing window and extended into the subterranean formation disposed around the lateral wellbore 128. As previously mentioned, the trajectory of the lateral wellbore 128 (e.g., branch section) may be directed or guided by the angled whipstock face 335 of the whipstock insert attachment 305. That is, the cutting assembly 400 may contact and travel along the surface of the angled whipstock face 335 of the whipstock insert attachment 305. As such, the trajectory of the cutting assembly 400 may be based at least in part on an angle and an orientation of the angled whipstock face 335

of the whipstock insert attachment 305 in the lateral wellbore 128. Moreover, once the casing window is created, the cutting assembly 400 may be removed from the wellbore. In some examples, the cutting assembly 400 may be extended into the subterranean formation prior to removal from the wellbore.

[0038] FIG. 7 illustrates a cross-sectional side view of a well system with a drilling assembly 450 extending a portion of a lateral wellbore 128. As depicted, the drilling assembly 450 may continue to drill in the lateral wellbore 128 to extend the lateral wellbore 128 toward a desired downhole location. In some examples, the construction of a lateral bore may require the use of multiple drilling assemblies to reach the desired downhole location. For example, a first drilling assembly may extend a first portion of the lateral bore hole to a certain measured depth before being removed from the wellbore and replaced with a second drilling assembly. In other examples, a single drilling assembly may be used to excavate the full length of the lateral bore.

[0039] FIG. 8 illustrates a cross-sectional side view of a well system with the whipstock retrieval tool 380 engaged with the whipstock insert attachment 305. As depicted, the whipstock retrieval tool 380 may be utilized to remove the whipstock insert attachment 305 from the nested position within the deflector assembly 250. The whipstock retrieval tool 380 can also be used as a running tool for deploying the whipstock and/or deflector and detachably secured to the whipstock insert attachment 305. For example, in an engaged position, direct contact occurs between an inner surface of the whipstock insert attachment 305 and an exterior of the whipstock retrieval tool 380. In particular, the whipstock insert attachment 305 may include at least one slot or feature formed in the inner surface of the whipstock insert attachment 305. Further, the whipstock retrieval tool 380 may include at least one locking feature 315 (e.g., radial piston, etc.) configured to expand into the at least one slot or feature of the whipstock insert attachment 305 in the engaged position.

[0040] Once the whipstock retrieval tool 380 is in the engaged position, the whipstock retrieval tool 380 may pull the whipstock assembly in the uphole direction to disengage the whipstock insert attachment 305 from the deflector assembly 250. Further, the at least one locking feature 318 of the whipstock insert attachment 305 may retract from the at least one slot or feature formed in the inner surface of the deflector assembly 250 which may allow the whipstock insert attachment 305 to be removed from the deflector assembly 250. Once the whipstock insert attachment 305 is disengaged from the deflector assembly 250, the whipstock insert attachment 305 and the

whipstock retrieval tool 380 may be removed from the wellbore by tripping out of hole with the whipstock insert attachment 305 engaged with the whipstock retrieval tool 380.

[0041] FIG. 9 illustrates a cross-sectional side view of a well system with a millable joint 525 disposed within a main wellbore. The installation may include an upper liner, upper liner anchor 530 and a fluted No-Go centralizer 535. The millable joint 525 may be detachably secured to a lateral liner running tool 300 and run-in-hole. The millable joint 525 may be made of any material including plastics, carbon fiber, fiber glass, aluminum, steel, other metal-based materials, or a combination thereof. The lateral liner running tool 300 may be detachably secured to the millable joint 525 such that, in an engaged position, an inner surface of the millable joint 525 interfaces with the lateral liner running tool 300. The millable joint 525 may contain a first portion sized to fit within the main wellbore 122, said first portion connecting with a second portion that is sized to fit within the lateral wellbore 128.

[0042] For example, the millable joint 525 may include at least one slot or feature formed in the inner surface of the millable joint 525. Further, the lateral liner running tool 300 may include at least one locking feature 315 (e.g., radial piston, collet etc.) configured to expand into the at least one slot or feature of the millable joint 525 in the engaged position. Contact between the locking feature 315 and the at least one slot or feature may secure the lateral liner running tool 300 to the millable joint 525. The millable joint 525 may be disposed within the well system such that the body of the millable joint 525 is disposed within both a portion of the lateral wellbore 128 and a portion of the main wellbore 122, thus disposing the millable joint 525 at a multi-lateral junction of more than one wellbore. As such, a portion of the millable joint 525 may traverse the previously formed casing window.

[0043] While the millable joint 525 may include a single joint with an upper liner anchor 530 and fluted No-Go centralizer 535 attached thereto, it may additionally include multiple joints secured in a longitudinal direction. Further, as illustrated, a portion of the millable joint 525 may contact the angled face of the deflector assembly 250. The fluted No-Go centralizer 535 may also abut a portion of the angled face of the deflector assembly 250 and may provide for a restrictive surface which prevents longitudinal movement of the millable joint 525 in the downhole direction. The fluted No-Go centralizer 535 can also be used to ensure placement of the millable joint 525 at the proper depth. The tubular string 540 may be installed along with the millable joint 525 using the

lateral liner running tool 300. Once the millable joint 525 is placed in the desired position, the upper liner anchor 530 may engage with the wall of the wellbore to secure the millable joint 525 in the wellbore. With the millable joint 525 secured in the wellbore, the at least one locking feature 315 of the lateral liner running tool 300 may retract from the at least one slot or feature formed in the inner surface of the millable joint 525 which may allow the lateral liner running tool 300 to be removed from the millable joint 525. After the deployment tool is disengaged from the millable joint 525, it may be tripped out of hole.

[0044] Moreover, once the lateral liner running tool 300 is tripped out of hole, a tubular string 540 may be run-in-hole to provide mechanical integrity and support for portion of the lateral wellbore 128 exposed to the subterranean formation. In a non-limiting example, the tubular string 540 may include liners, casing, or other suitable forms of casing and liners. In some examples, the tubular string 540 disposed in the lateral wellbore 128 may be cemented, uncemented, partially cemented, stage cemented, or combinations thereof. In further examples, the tubular string 540 disposed in the lateral wellbore 128 may be secured to the wellbore wall with annular barrier 545 providing annular isolation such as a packer or similar device. In other examples, the tubular string 540 may be secured to the wellbore wall with a non-isolating device such as an anchor assembly or similar device. The tubular string 540 should isolate the formation / pressure regime to further allow for the next smaller hole section to be drilled.

[0045] FIG. 10 illustrates a cross-sectional side view of a well system with a drilling assembly 450 extending a portion of a lateral wellbore 128, from the previously installed tubular string 540, which may be a casing / liner string. In particular, the drilling assembly 450 may include a drill bit run into the lateral wellbore 128 and tubular string 540, configured to drill a smaller hole section from the bottom portion of the lateral wellbore 128, thus extending the lateral wellbore 128. Further, the millable joint 525 may be configured to guide the drilling assembly 450 from the main wellbore 122 into the lateral wellbore 128 and tubular string 540. Now that the lateral wellbore 128 has been sealed off / isolated with tubular string 540, alteration can now be made to the fluid system, as required for the next wellbore section to be drilled.

[0046] FIG. 11 illustrates a cross-sectional side view of a lower completion installation in the lateral wellbore 128 and tubular string 540. For example, one or more completion features such as a plurality of screens, liners, or any suitable completion feature may be run-in-hole and installed

in a lower portion of the lateral wellbore 128 and tubular string 540. Here, a lateral liner hanger 575 is used in addition to a lateral screen completion 585. As shown, the millable joint 525 contains a sidewall 560 which is positioned near the central axis of the main wellbore 122. The millable joint 525 may be shaped so that a portion of the millable joint 525 is within the main wellbore 122 while an opposing portion is within the lateral wellbore 128. The portion that is within the main wellbore 122 should contain the sidewall 560. The sidewall 560 is also near the opening for the lateral wellbore 128.

[0047] FIG. 12 illustrates a cross-sectional side view of a cutting assembly 420 disposed within a cutting guide 700 for directing the cutting assembly 400 to regain access to the main wellbore area downhole once construction of the lateral wellbore section(s) are complete. In particular, the cutting guide 700 is configured to direct the cutting assembly 400 to engage and cut through a sidewall 560 of the millable joint 525. The sidewall 560 may be aligned with the base deflector such that the cutting through the sidewall 560 of the millable joint 525, via the cutting assembly 400, may open a fluid path between the millable joint 525 and the deflector assembly 250.

[0048] Moreover, as depicted, a hydraulic locking tool 390 and a cutting assembly 400 may be disposed on a work string 800. Further, during installation of the cutting guide 700, the hydraulic locking tool 390 may be detachably secured to a cutting guide 700 such that the hydraulic locking tool 390, the cutting assembly 400, and the cutting guide 700 may be run-in-hole together. The cutting guide 700 may include at least one slot or feature formed in the inner surface of the cutting guide 700. The hydraulic locking tool 390 may include at least one locking feature 315 (e.g., radial piston, etc.) configured to expand into the at least one slot or feature of the cutting guide 700 in the engaged position. Contact between the locking feature 315 and the at least one slot or feature may secure the hydraulic locking tool 390 to the cutting guide 700 in a locking position.

[0049] With the locking feature of the hydraulic locking tool 390 engaged with the at least one slot or feature of the cutting guide 700, the cutting guide 700 may be relayed to a desired position in a wellbore by the work string 800 on which the hydraulic locking tool 390 and cutting assembly 400 are disposed. As such, the hydraulic locking tool 390, cutting assembly 400, and cutting guide 700 may be run in hole on the work string 800 to place the cutting guide 700 in a desired location. For example, as depicted, the cutting guide 700 may be run into and at least partially disposed within the millable joint 525. Further, at least a portion of the cutting guide 700 (e.g., lateral guide

portion 730 may be disposed in the lateral wellbore 128, and a remaining portion (e.g., main guide portion 720) may be disposed within the main wellbore 122. The lateral guide portion 730 may contain a guide nose including a hole within the nose to allow fluid communication from the lateral wellbore into the main wellbore. The lateral guide portion 730 may have an outside diameter that is nearly the same as the millable joint or is sized to fit snugly within the millable joint.

[0050] Moreover, an outer surface of the cutting guide 700 may include an alignment key 710. The alignment key 710 may include a retractable locking feature 740 (e.g., radial piston, etc.), where the retractable locking feature 740 may extend such that it engageably secures with a slot or feature. Additionally, the retractable locking feature 740 may retract such that an outward facing edge of the retractable locking feature 740 becomes at least flush with an outer surface of the hydraulic locking tool 390. With the cutting guide 700 positioned in the lateral wellbore 128, and in the lateral liner / millable joint 525, the retractable locking feature 740 of the alignment key 710 may extend into a slot or feature disposed on an inner surface of the millable joint 525. The cutting guide 700 may be oriented and aligned using the alignment key 710, which engages the upper liner anchor 530 (ex. muleshoe), the millable joint 525 may have no orientation or locking feature in some embodiments. The position of the slot or feature on the inner surface of the millable joint 525 may restrict the engaged orientation of the cutting guide 700 such that it is oriented in a preferred direction.

[0051] The engagement of the retractable locking feature 740 with the slot or feature may secure the cutting guide 700 to the millable joint 525 at a position in accordance with the location of the alignment key 710 and the slot or feature. In some examples, the work string 800, or a portion of the work string 800 on which the cutting guide 700 is disposed, may be rotated to facilitate engagement of the alignment key 710 with the slot or feature disposed on the inner surface of the millable joint 525. Additionally, or alternatively, the outer surface of the cutting guide 700 may further include a secondary locking feature 750 (ex. collet) for aligning and/or orienting the cutting guide 700 with respect to the millable joint 525.

[0052] The cutting guide 700 contains a guide surface 701 which guides the cutting assembly 400 into a proper orientation to remove a portion of the sidewall 560. This guide surface 701 is generally parallel to the central axis of the main wellbore 122 and is located adjacent to the lateral guide portion 730 which extends into the lateral wellbore 128. The guide surface 701 may be at an

[0053] FIG. 13 illustrates a cross-sectional side view of a well system with a cutting assembly 400 cutting the fluid path through the sidewall 560 in the millable joint 525. When the cutting guide 700 is installed in the millable joint 525 (e.g., alignment key 710, secondary locking feature 750 (ex. collet), or both are engaged with the interior surfaces of the millable joint 525), the hydraulic locking tool 390 may be configured to be disconnected from cutting guide 700 such that the cutting assembly 400 may move along a path defined by the cutting guide 700 to engage and preferably remove a desired portion of the millable joint 525 (e.g., the sidewall 560 aligned with the deflector assembly 250).

[0054] In particular, the locking feature 315 of the hydraulic locking tool 390 may retract to allow the work string 800, hydraulic locking tool 390, and cutting assembly 400 to move with respect to the cutting guide 700. As such, the work string 800 may be moved to drive the cutting assembly 400 along the path defined by the cutting guide 700 to engage the desired portion (e.g., sidewall 560) of the millable joint 525. Alternatively, the cutting assembly 400 may engage with a portion of the cutting guide 700 near the central axis of the main wellbore such that the cutting assembly 400 may cut the fluid flow path through a combination of both said portion of the cutting guide 700 and the millable joint 525.

[0055] In some examples, the work string 800 may be rotated to facilitate the removal of cuttings created during the cutting operations. The cutting assembly 400 may include a drill bit, a plasma cutter, a chemical cutter, a hydraulic cutter, abrasion cutter, or another form of mechanical, chemical, or hydraulic cutter.

[0056] Moreover, in response to completing cutting operations, the cutting assembly 400 and the hydraulic locking tool 390 may be removed from the wellbore by pulling out of hole with the work string 800. However, prior to pulling out of hole, the hydraulic locking tool 390 may be re-secured to the cutting guide 700, such that the cutting guide 700 may be removed from the well system when the work string 800 is pulled from the wellbore. As previously mentioned, the cutting guide 700 may include at least one slot or feature formed in the inner surface of the cutting guide 700. The hydraulic locking tool 390 may include at least one locking feature 315 (e.g., radial piston, etc.) configured to expand into the at least one slot or feature of the cutting guide 700 in the engaged position. Contact between the locking feature 315 and the at least one slot or feature may secure the hydraulic locking tool 390 to the cutting guide 700 in a locking position. With the

locking feature 315 of the hydraulic locking tool 390 engaged with the at least one slot or feature of the cutting guide 700, the cutting guide 700 may be tripped out of the wellbore.

[0057] FIG. 14 illustrates a cross-sectional side view of a well system with the passageway 850 (now in place of the sidewall 560) cut through a millable joint 525. As depicted, the sidewall portion of the millable joint 525 has been removed, via the cutting assembly 400 to form the passageway 850 through the millable joint 525. During completion and/or production operations, fluids and/or wellbore equipment may pass through the passageway 850.

[0058] FIG. 15 illustrates a cross-sectional side view of a well system with a straddle completion system 920 disposed within the main wellbore 122 and lateral wellbore 128.

[0059] FIG. 16 illustrates a cross-sectional side view of a well system with a dual leg junction completion system 940 disposed within the main wellbore 122 and the lateral wellbore 128.

[0060] Statement 1. A downhole system comprising: a millable joint having a first portion shaped to extend into a main wellbore and a second portion shaped to extend into a lateral wellbore; a cutting guide at least partially disposable within the millable joint; and a cutting assembly configured to move alongside the cutting guide until engaging with a sidewall of the millable joint.

[0061] Statement 2. The downhole system of Statement 1 further comprising: the cutting guide comprises a lateral guide portion which is shaped to extend into the lateral wellbore and a main guide portion which is shaped to extend into the main wellbore.

[0062] Statement 3. The downhole system of Statement 1 or Statement 2 further comprising: a guide surface on the cutting guide which is parallel to a central axis of the main wellbore.

[0063] Statement 4. The downhole system of any preceding Statement wherein: the sidewall of the millable joint is angled relative to a central axis of the main wellbore.

[0064] Statement 5. The downhole system of any preceding Statement wherein: the cutting guide is disposed within the first portion of the millable joint.

[0065] Statement 6. The downhole system of any preceding Statement wherein: the sidewall is positioned along a central axis of the main wellbore.

[0066] Statement 7. The downhole system of any preceding Statement further comprising: a fluted no-go centralizer placed within the millable joint.

[0067] Statement 8. The downhole system of any preceding Statement wherein: the sidewall of the millable joint is parallel to an angled face on a base deflector.

[0068] Statement 9. A method for operating a downhole system comprising the steps of: removably securing a lateral liner running tool to a work string; removably securing a millable joint as part of a liner string to the lateral liner running tool; running the millable joint downhole via the work string until reaching a multi-lateral junction of more than one wellbore; securing the millable joint in a position where a first portion of the millable joint is located within a main wellbore with a second portion of the millable joint located within a lateral wellbore; disconnecting the lateral liner running tool from the liner including millable joint; removably securing a cutting guide to a hydraulic locking tool; running the cutting guide downhole via the work string until reaching the millable joint; securing the cutting guide within the millable joint; disconnecting the hydraulic locking tool from the cutting guide; securing a cutting assembly to the hydraulic locking tool; running the cutting assembly downhole via the work string until reaching a sidewall portion of the millable joint; and removing the sidewall portion of the millable joint with the cutting assembly.

[0069] Statement 10. The method of Statement 9 wherein: the step of removing the sidewall portion of the millable joint allows fluid communication through the millable joint.

[0070] Statement 11. The method of Statement 9 or Statement 10 wherein: the cutting guide directs the cutting assembly to move along a central axis of the main wellbore.

[0071] Statement 12. The method of any one of Statements 9 to 11 further comprising the step of: disposing a completion system within at least one wellbore extending from the multilateral junction.

[0072] Statement 13. The method of one of Statements 9 to 12 further comprising the step of: disposing a dual leg junction completion system within two wellbores at the millable joint.

[0073] Statement 14. The method of one of Statements 9 to 13 wherein: the cutting guide directs the cutting assembly within the millable joint to engage with said sidewall portion of the millable joint for removal.

[0074] Statement 15. The method of one of Statements 9 to 14 wherein: the step of securing the cutting guide within the millable joint is performed by placing a lateral guide portion of the cutting guide within one wellbore at the multi-lateral junction.

[0075] Statement 16. A downhole deflector assembly, comprising: a deflector securable within a main wellbore, wherein an uphole end of the deflector comprises an angled face configured to

direct one or more tubulars from well bore to a lateral bore; and a whipstock insert attachment detachably securable to the deflector, wherein the whipstock insert attachment at least partially covers the uphole end of the deflector, and wherein the whipstock insert attachment is configured to detach from the deflector in response to engagement with a hydraulic deployment and retrieval tool.

[0076] Statement 17. The downhole deflector assembly of Statement 16 further comprising: a feature positioned on an inner surface of the whipstock insert attachment and sized to accept a portion of the hydraulic deployment and retrieval tool.

[0077] Statement 18. The downhole deflector assembly of Statement 16 or Statement 17 further comprising: a slot positioned on an inner surface of the whipstock insert attachment and sized to accept a portion of the hydraulic deployment and retrieval tool as a work string moves the hydraulic deployment and retrieval tool.

[0078] Statement 19. The downhole deflector assembly of one of Statements 16 to 18 to further comprising: a feature positioned on an inner surface of the deflector and sized to accept a portion of the whipstock insert attachment as a work string moves the hydraulic deployment and retrieval tool.

[0079] Statement 20. The downhole deflector assembly of any one of Statements 16 to 20 further comprising: a work string attached to the hydraulic deployment and retrieval tool; and a pin which secures the whipstock insert attachment to the deflector; wherein the pin shears off when an uphole force is applied to the hydraulic deployment and retrieval tool via the work string, allowing the whipstock insert attachment to be separated from the deflector.

[0080] For the sake of brevity, only certain ranges are explicitly disclosed herein. However, ranges from any lower limit may be combined with any upper limit to recite a range not explicitly recited, as well as, ranges from any lower limit may be combined with any other lower limit to recite a range not explicitly recited, in the same way, ranges from any upper limit may be combined with any other upper limit to recite a range not explicitly recited. Additionally, whenever a numerical range with a lower limit and an upper limit is disclosed, any number and any included range falling within the range are specifically disclosed. In particular, every range of values (of the form, “from about a to about b,” or, equivalently, “from approximately a to b,” or, equivalently, “from approximately a-b”) disclosed herein is to be understood to set forth every number and range

encompassed within the broader range of values even if not explicitly recited. Thus, every point or individual value may serve as its own lower or upper limit combined with any other point or individual value or any other lower or upper limit, to recite a range not explicitly recited.

[0081] Therefore, the present embodiments are well adapted to attain the ends and advantages mentioned as well as those that are inherent therein. The particular embodiments disclosed above are illustrative only, as the present embodiments may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Although individual embodiments are discussed, all combinations of each embodiment are contemplated and covered by the disclosure. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. Also, the terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee. It is therefore evident that the particular illustrative embodiments disclosed above may be altered or modified and all such variations are considered within the scope and spirit of the present disclosure.

CLAIMS

What is claimed is:

1. A downhole system comprising:
 - a millable joint having a first portion shaped to extend into a main wellbore and a second portion shaped to extend into a lateral wellbore;
 - a cutting guide at least partially disposable within the millable joint; and
 - a cutting assembly configured to move alongside the cutting guide until engaging with a sidewall of the millable joint.
2. The downhole system of claim 1 further comprising:
 - the cutting guide comprises
 - a lateral guide portion which is shaped to extend into the lateral wellbore and
 - a main guide portion which is shaped to extend into the main wellbore.
3. The downhole system of claim 1 further comprising:
 - a guide surface on the cutting guide which is parallel to a central axis of the main wellbore.
4. The downhole system of claim 1 wherein:
 - the sidewall of the millable joint is angled relative to a central axis of the main wellbore.
5. The downhole system of claim 1 wherein:
 - the cutting guide is disposed within the first portion of the millable joint.
6. The downhole system of claim 1 wherein:
 - the sidewall is positioned along a central axis of the main wellbore.
7. The downhole system of claim 1 further comprising:
 - a fluted no-go centralizer placed within the millable joint.
8. The downhole system of claim 1 wherein:

the sidewall of the millable joint is parallel to an angled face on a base deflector.

9. A method for operating a downhole system comprising the steps of:

removably securing a lateral liner running tool to a work string;
removably securing a millable joint as part of a liner string to the lateral liner running tool;
running the millable joint downhole via the work string until reaching a multi-lateral junction of more than one wellbore;
securing the millable joint in a position where a first portion of the millable joint is located within a main wellbore with a second portion of the millable joint located within a lateral wellbore;
disconnecting the lateral liner running tool from the liner including millable joint;
removably securing a cutting guide to a hydraulic locking tool;
running the cutting guide downhole via the work string until reaching the millable joint;
securing the cutting guide within the millable joint;
disconnecting the hydraulic locking tool from the cutting guide;
securing a cutting assembly to the hydraulic locking tool;
running the cutting assembly downhole via the work string until reaching a sidewall portion of the millable joint; and
removing the sidewall portion of the millable joint with the cutting assembly.

10. The method of claim 9 wherein:

the step of removing the sidewall portion of the millable joint allows fluid communication through the millable joint.

11. The method of claim 9 wherein:

the cutting guide directs the cutting assembly to move along a central axis of the main wellbore.

12. The method of claim 9 further comprising the step of:

disposing a completion system within at least one wellbore extending from the multilateral junction.

13. The method of claim 9 further comprising the step of:

disposing a dual leg junction completion system within two wellbores at the millable joint.

14. The method of claim 9 wherein:

the cutting guide directs the cutting assembly within the millable joint to engage with said sidewall portion of the millable joint for removal.

15. The method of claim 9 wherein:

the step of securing the cutting guide within the millable joint is performed by placing a lateral guide portion of the cutting guide within one wellbore at the multi-lateral junction.

16. A downhole deflector assembly, comprising:

a deflector securable within a main wellbore, wherein an uphole end of the deflector comprises an angled face configured to direct one or more tubulars from well bore to a lateral bore; and

a whipstock insert attachment detachably securable to the deflector, wherein the whipstock insert attachment at least partially covers the uphole end of the deflector, and wherein the whipstock insert attachment is configured to detach from the deflector in response to engagement with a hydraulic deployment and retrieval tool.

17. The downhole deflector assembly of claim 16 further comprising:

a feature positioned on an inner surface of the whipstock insert attachment and sized to accept a portion of the hydraulic deployment and retrieval tool.

18. The downhole deflector assembly of claim 16 further comprising:

a slot positioned on an inner surface of the whipstock insert attachment and sized to accept a portion of the hydraulic deployment and retrieval tool as a work string moves the hydraulic deployment and retrieval tool.

19. The downhole deflector assembly of claim 16 further comprising:

a feature positioned on an inner surface of the deflector and sized to accept a portion of the whipstock insert attachment as a work string moves the hydraulic deployment and retrieval tool.

20. The downhole deflector assembly of claim 16 further comprising:

a work string attached to the hydraulic deployment and retrieval tool; and

a pin which secures the whipstock insert attachment to the deflector;

wherein the pin shears off when an uphole force is applied to the hydraulic deployment and retrieval tool via the work string, allowing the whipstock insert attachment to be separated from the deflector.

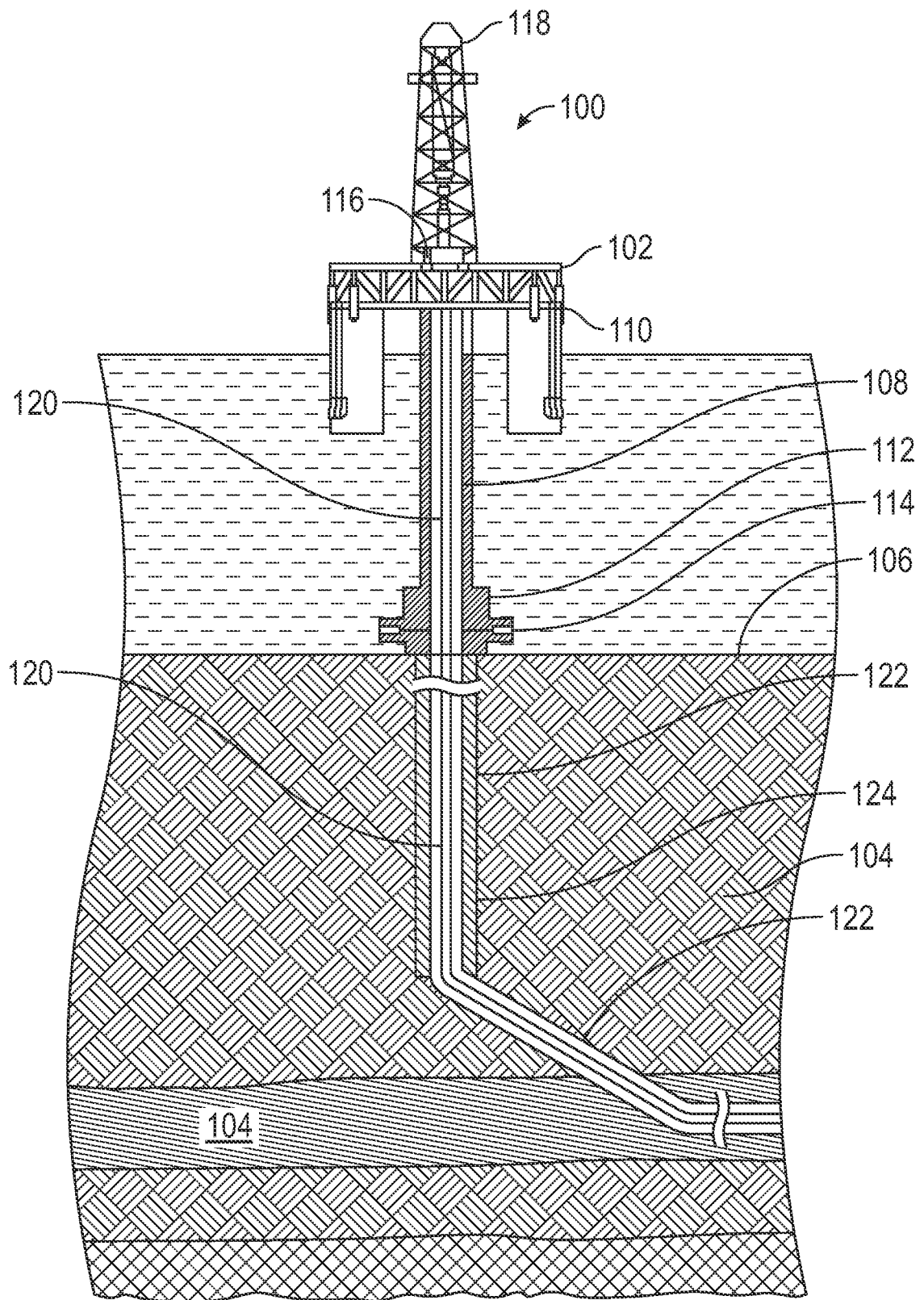


FIG. 1

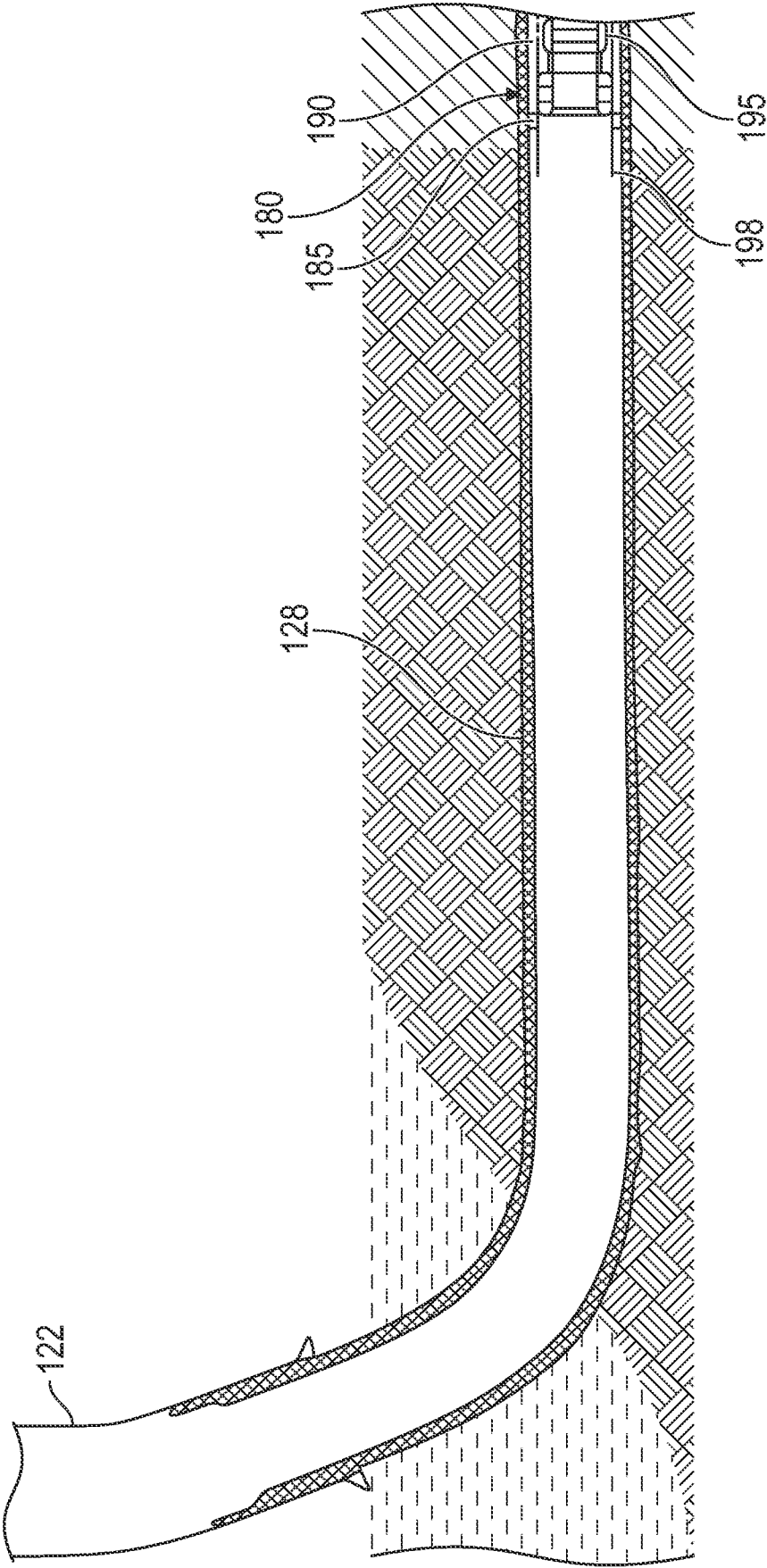


FIG. 2

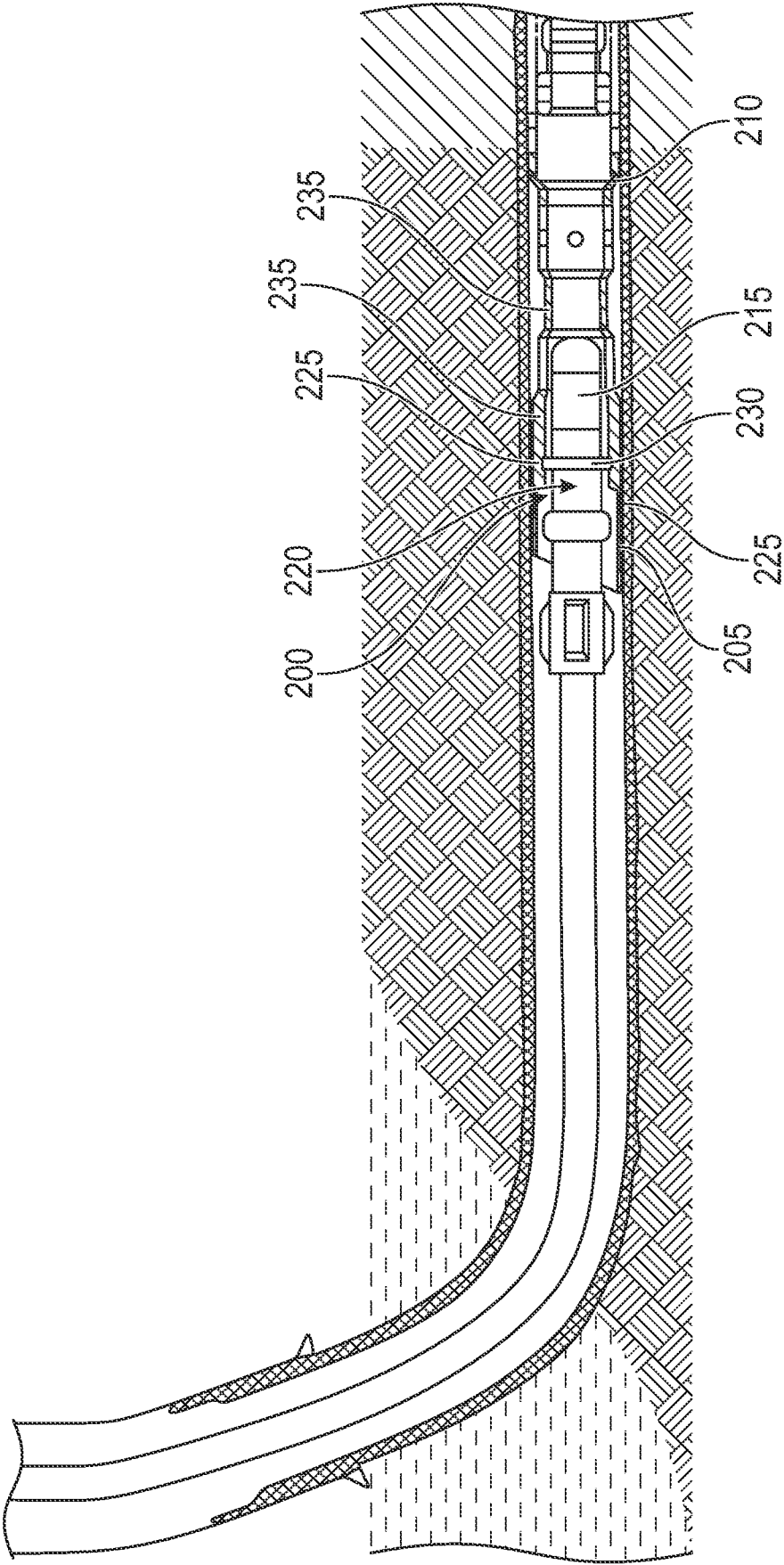


FIG. 3

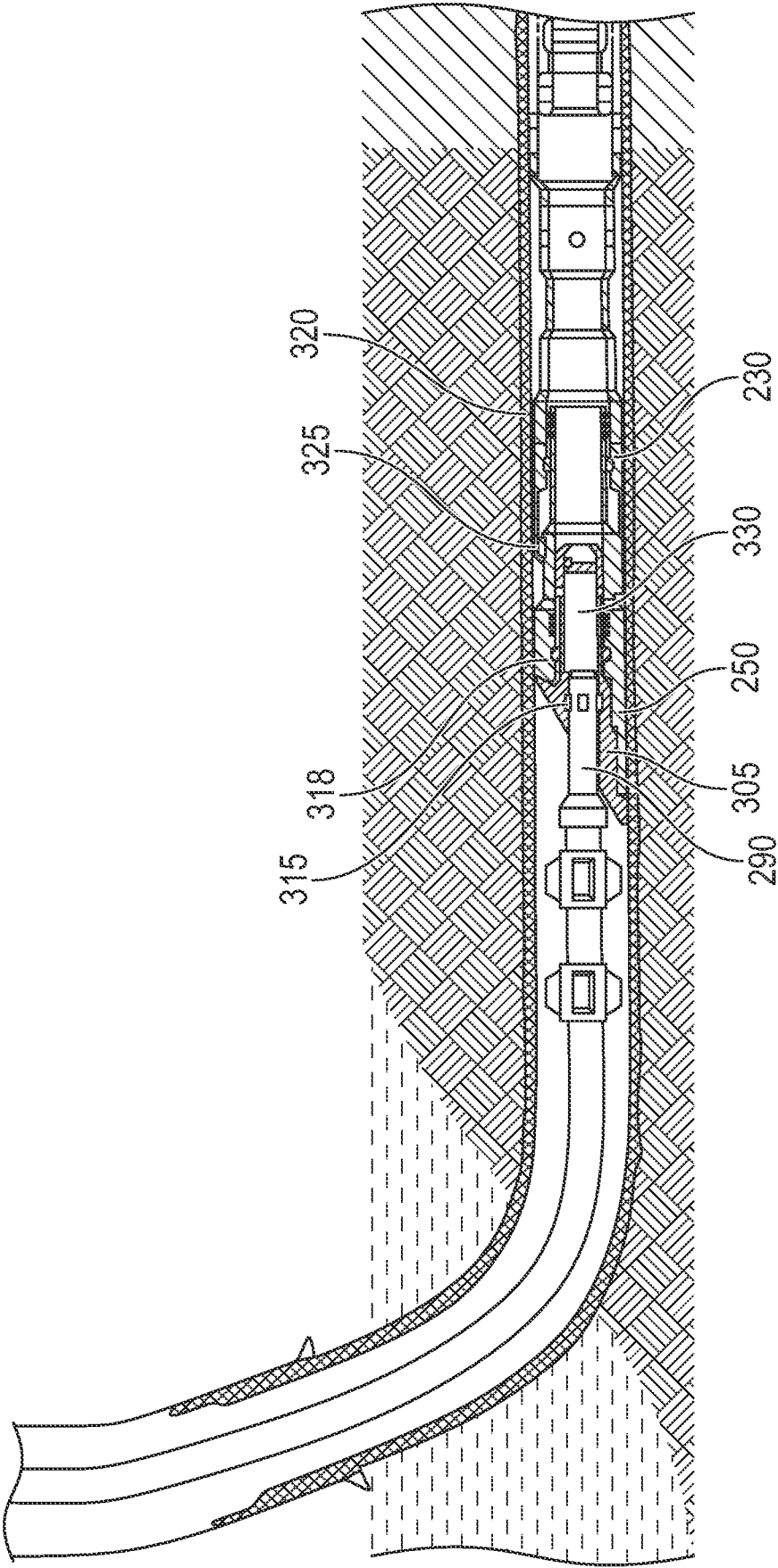


FIG. 4

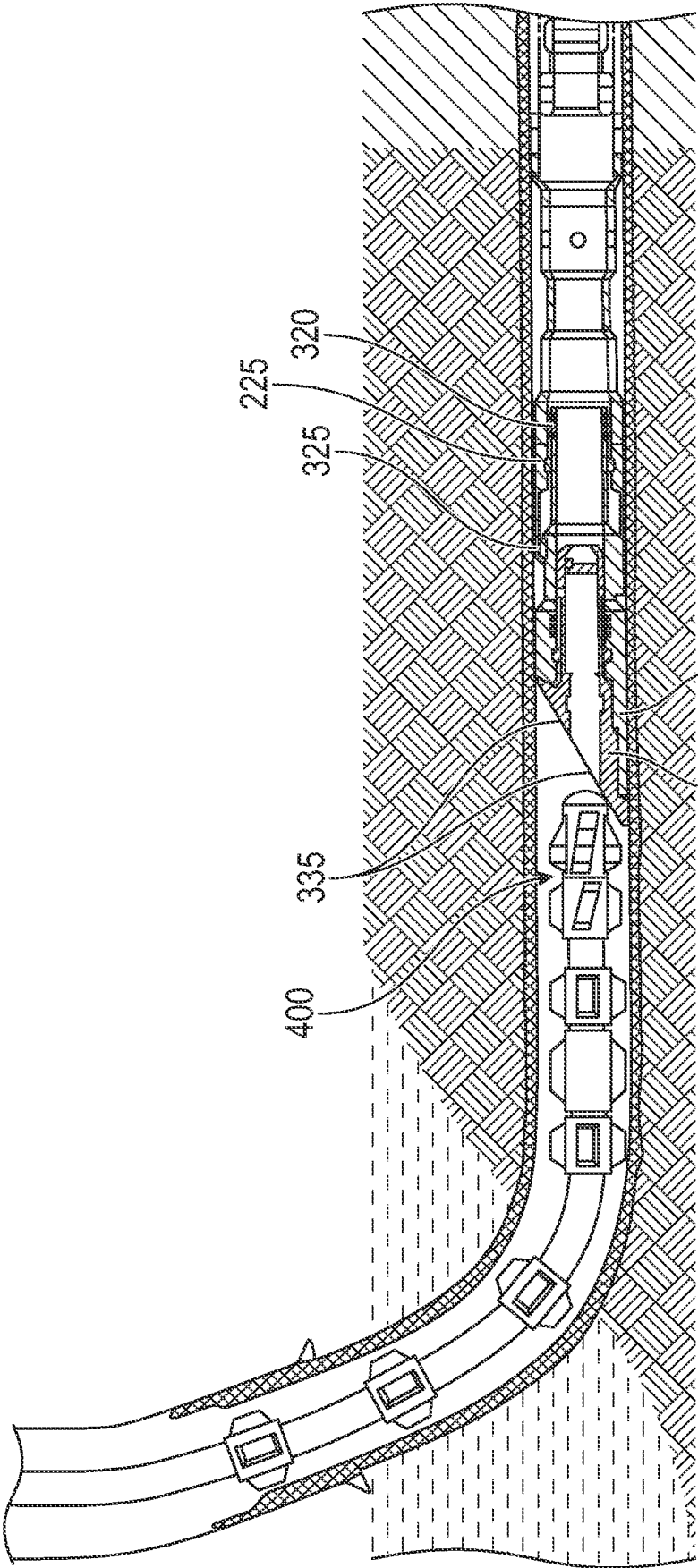


FIG. 5

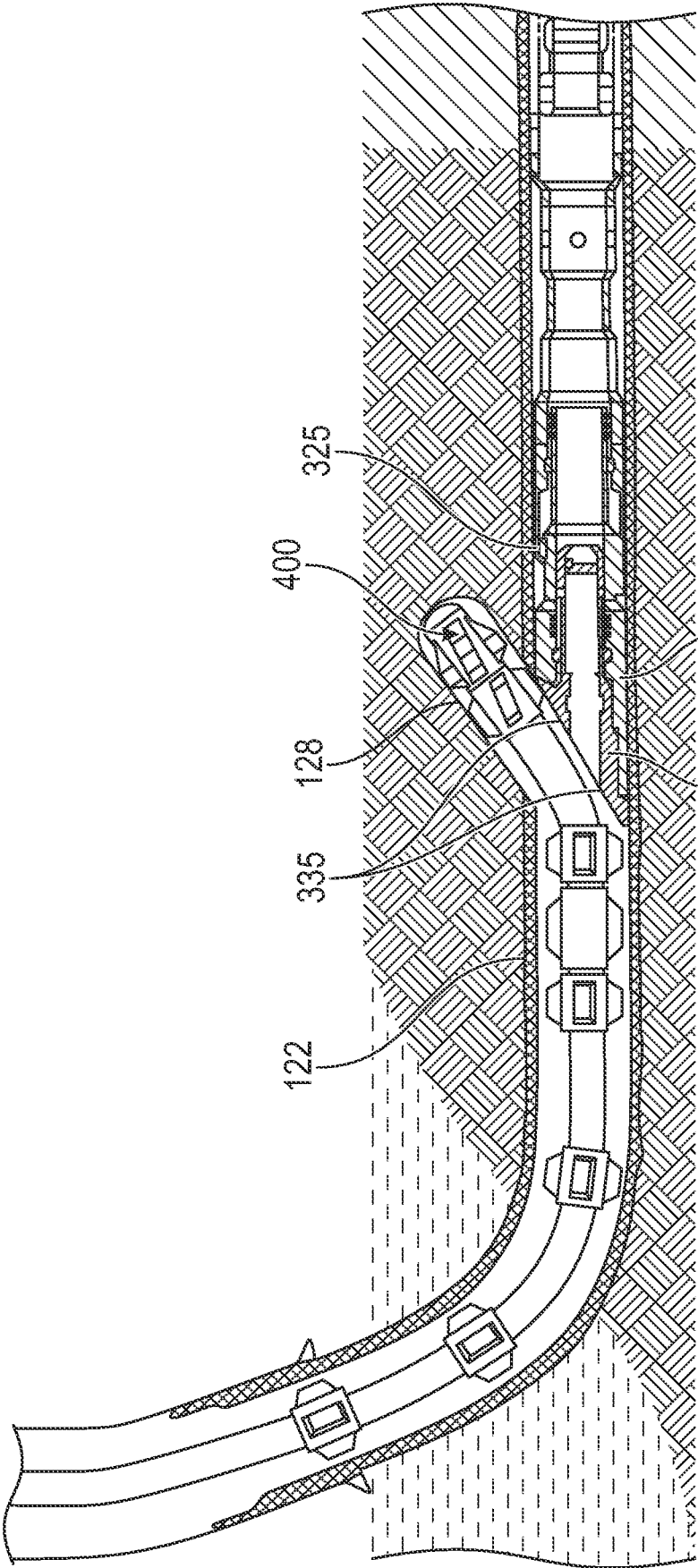


FIG. 6

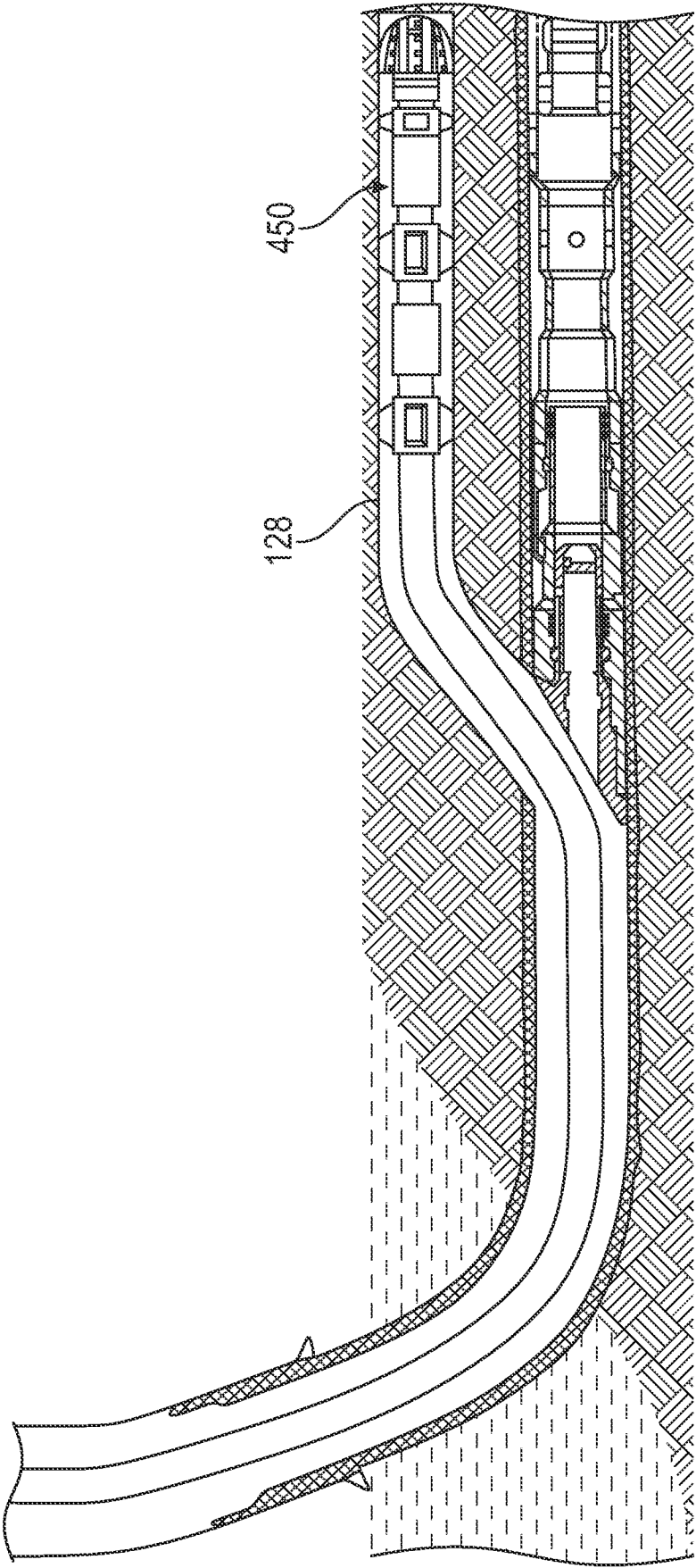


FIG. 7

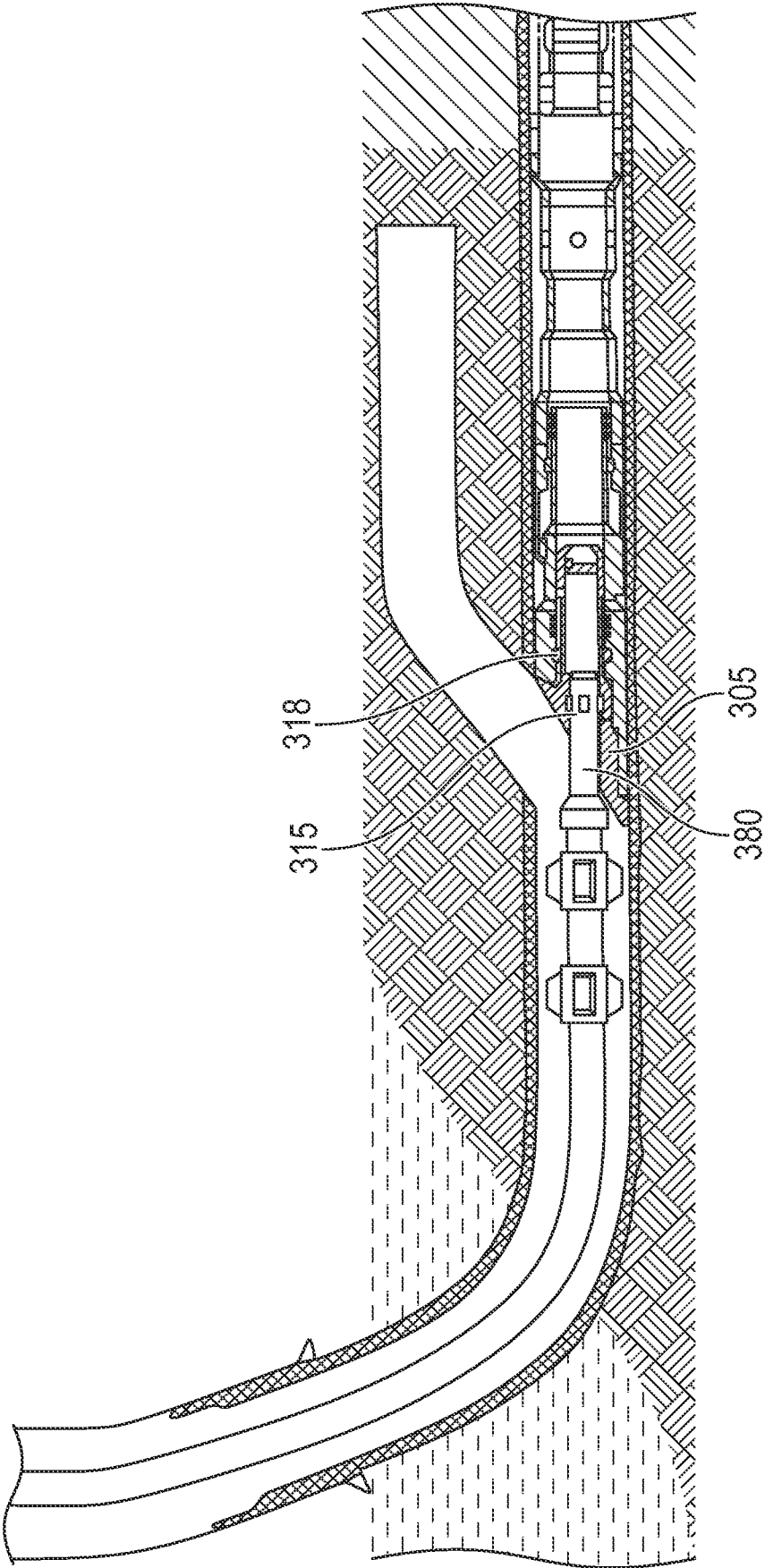


FIG. 8

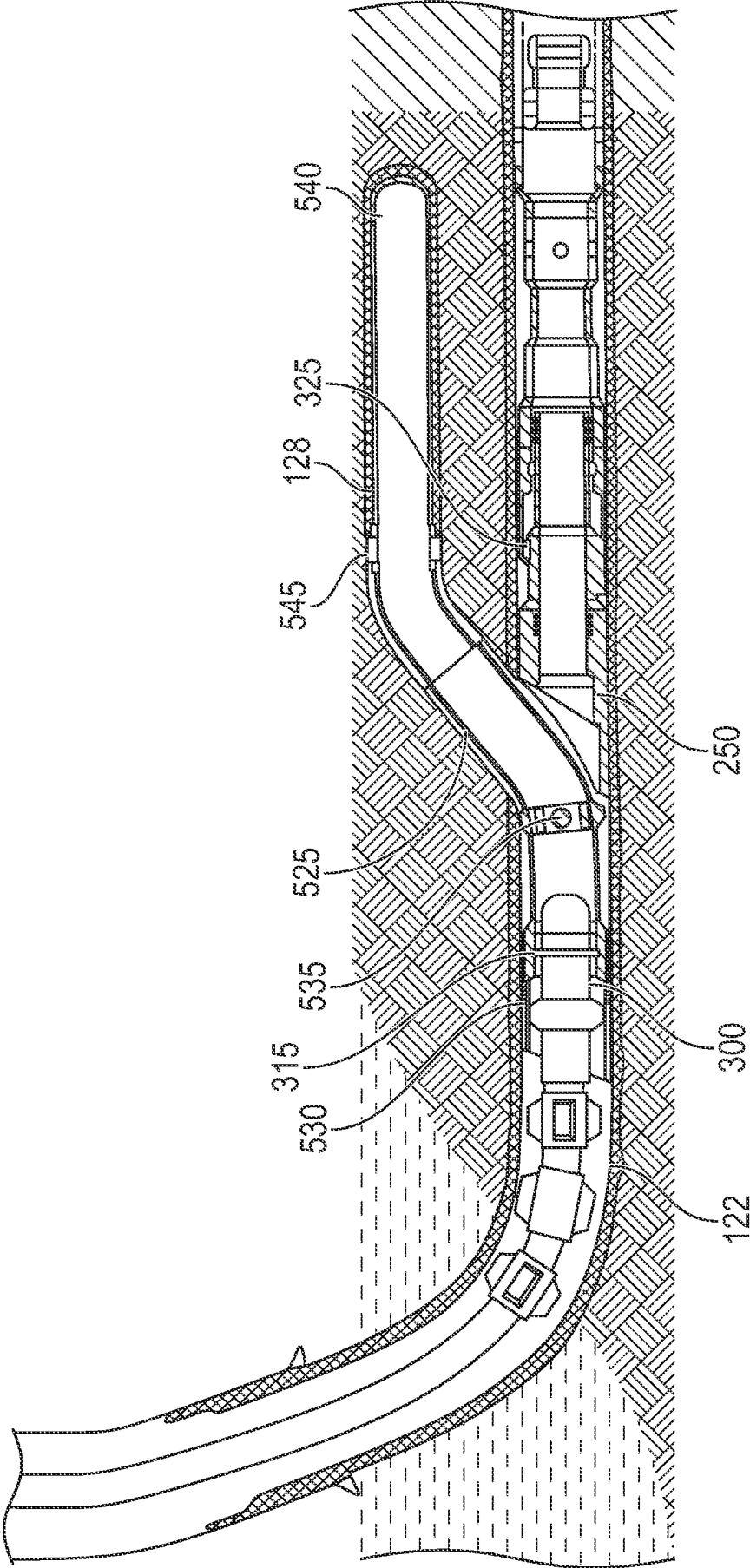


FIG. 9

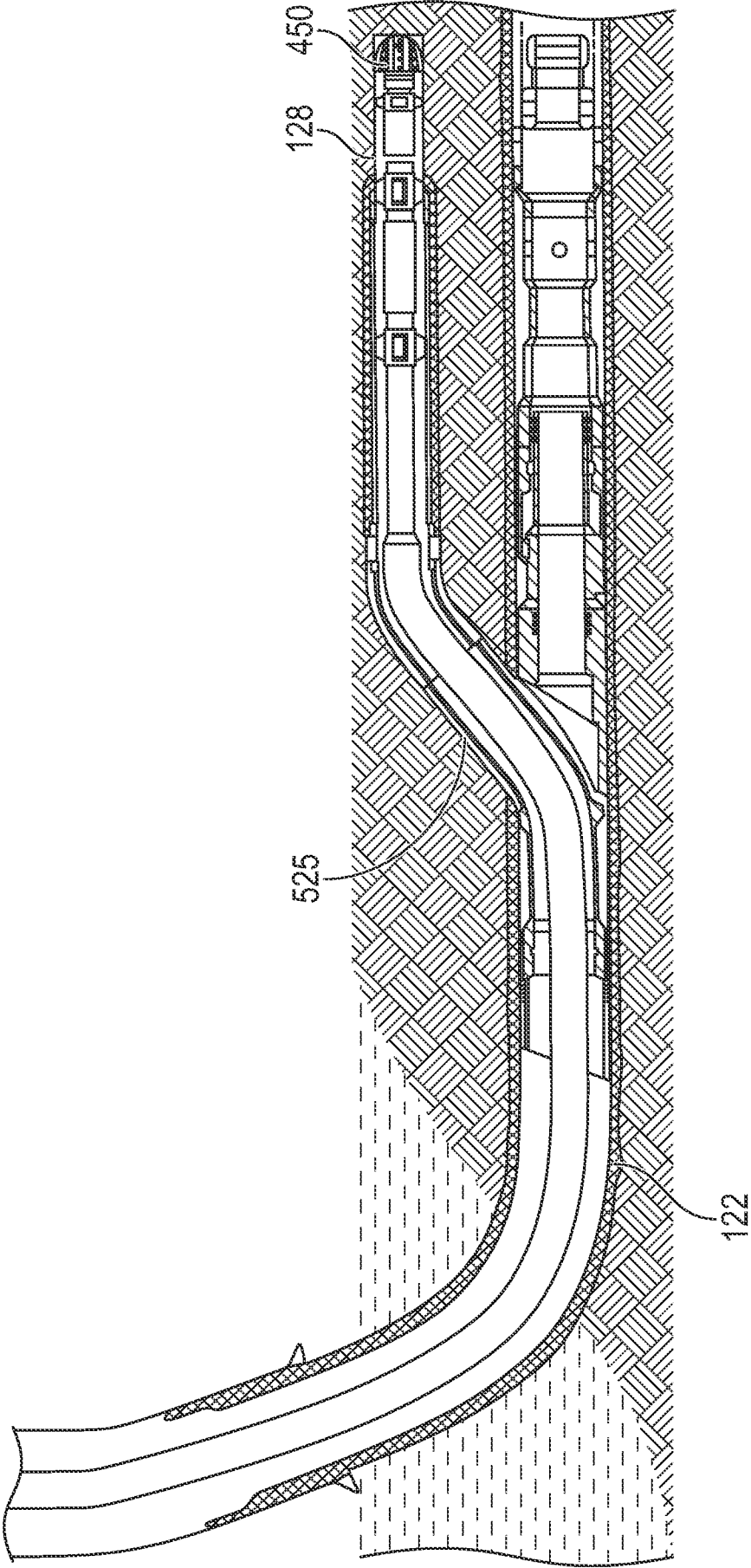


FIG. 10

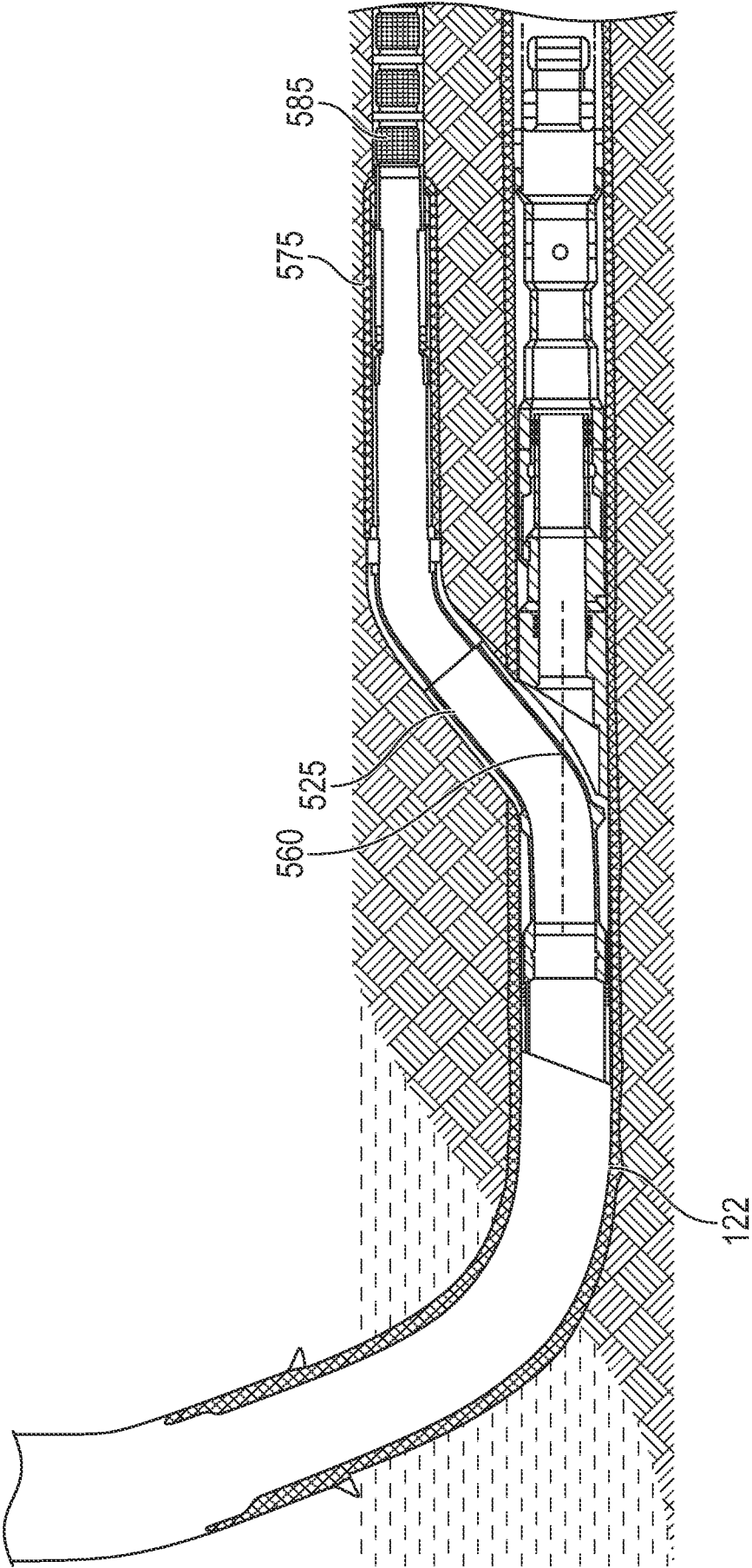
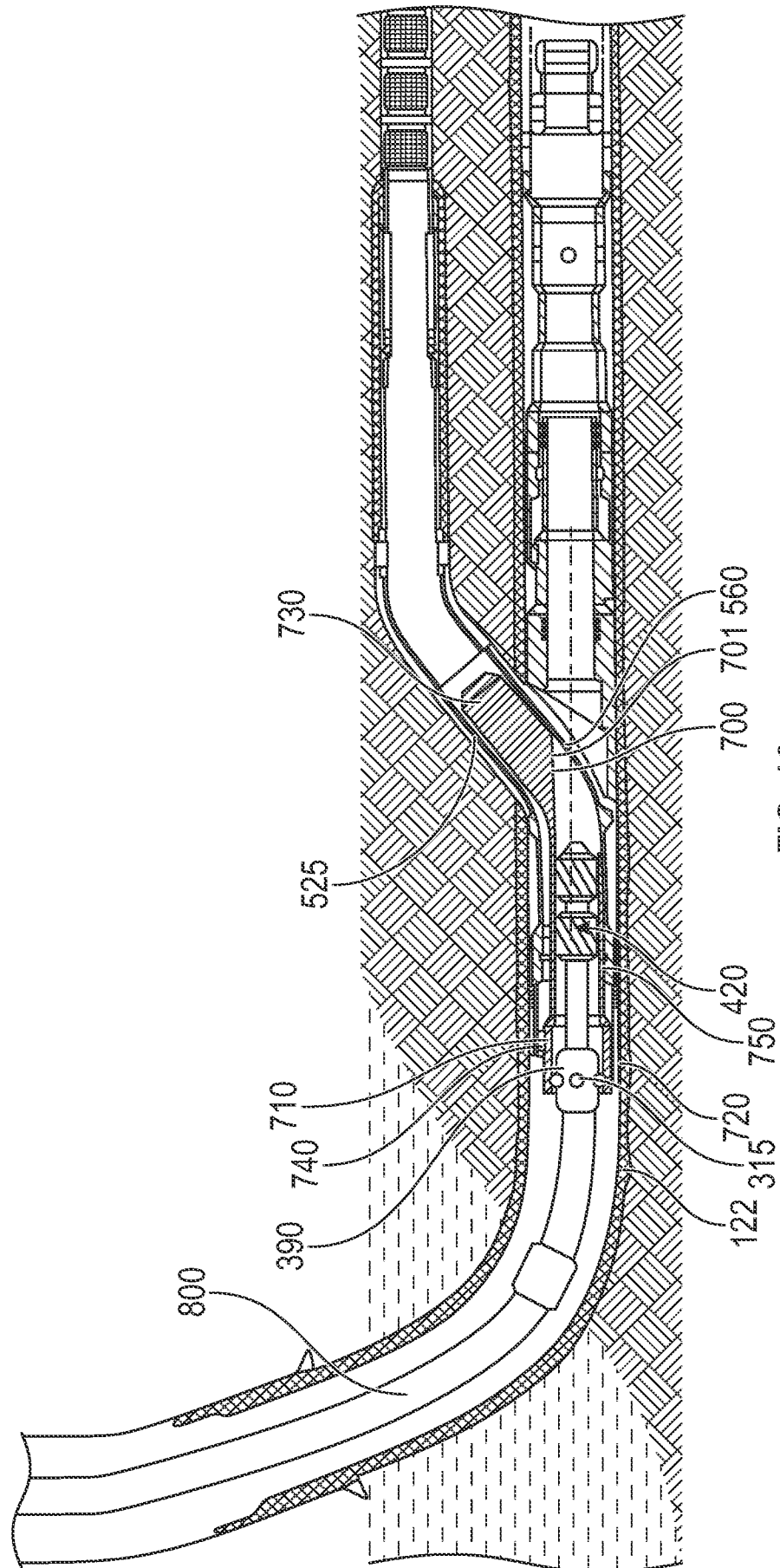


FIG. 11



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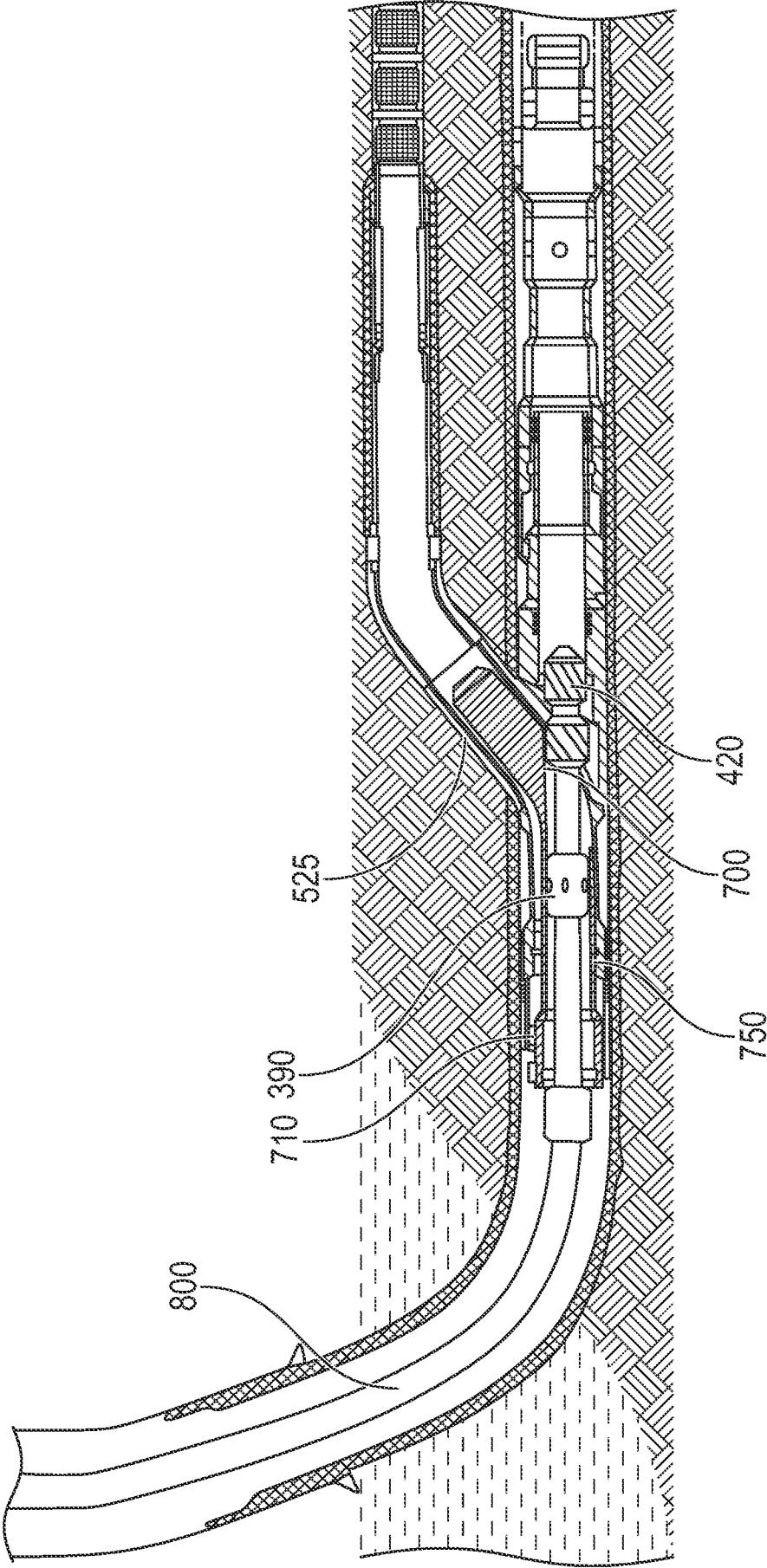


FIG. 13

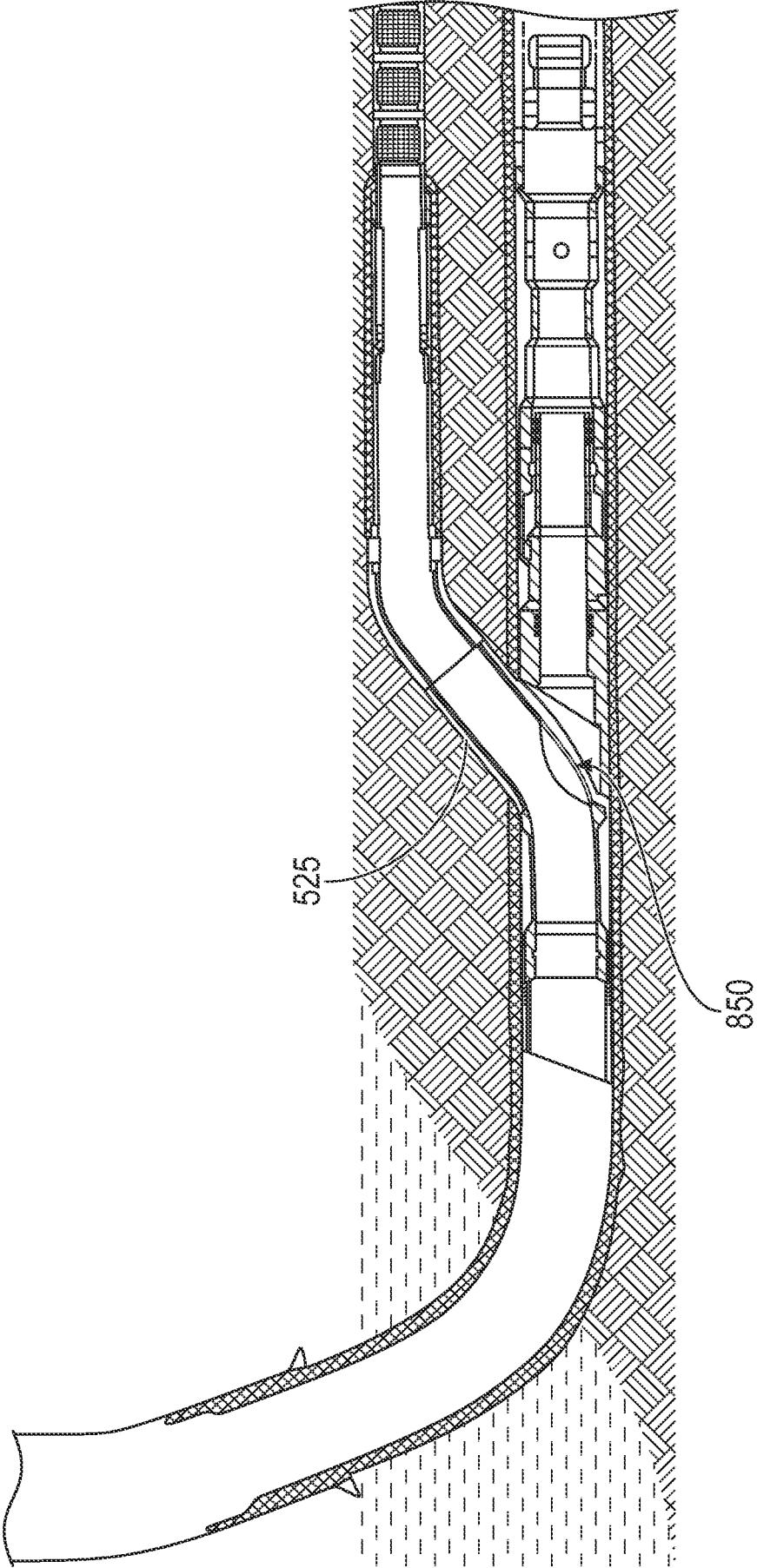


FIG. 14

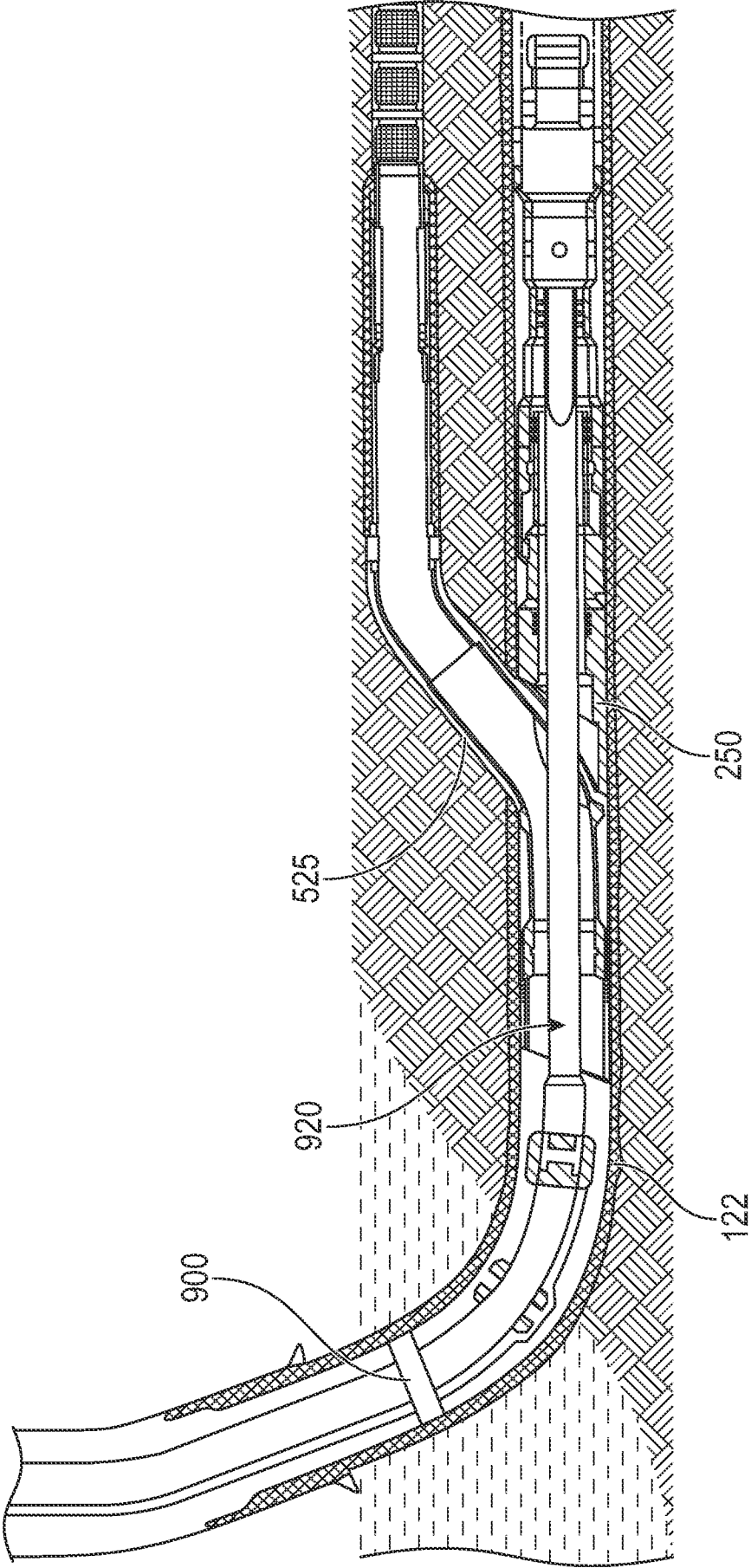
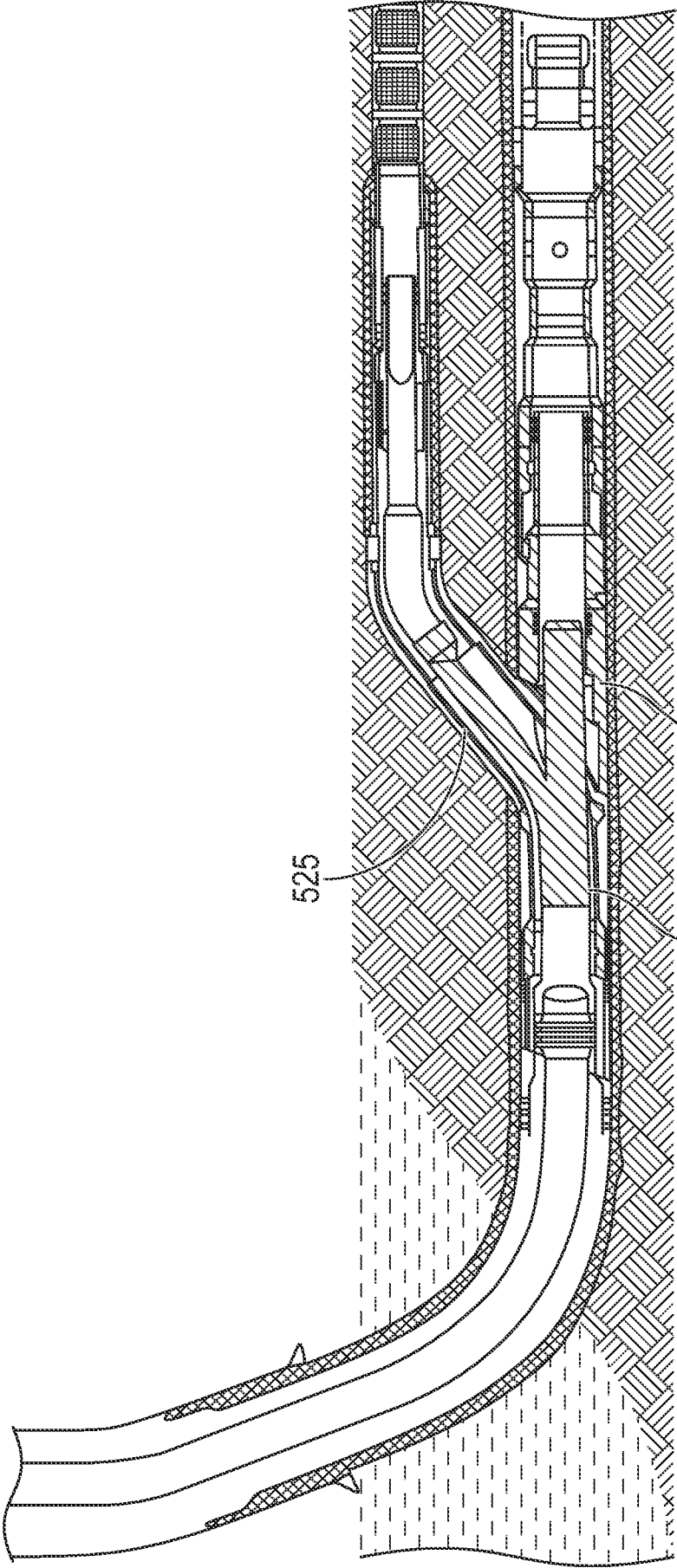


FIG. 15



525

940

250

FIG. 16