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(54) Titre : INSTALLATION DE BARRIERES MECANQUES EN UN SEUL PASSAGE
(54) Title: SETTING MECHANICAL BARRIERS IN A SINGLE RUN

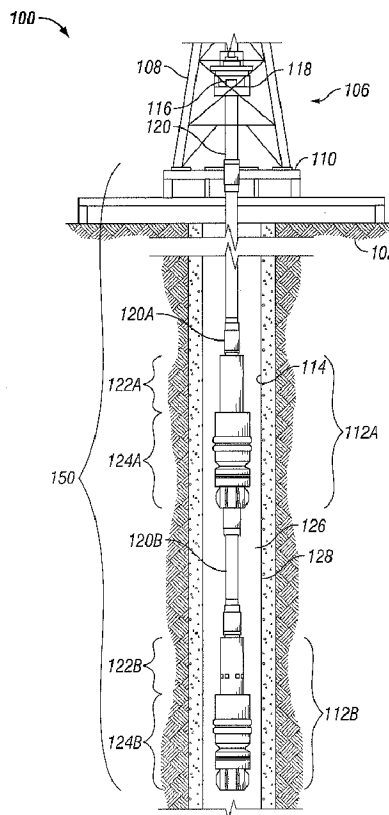


FIG. 1

(57) **Abrégé/Abstract:**

An operation may require isolation of a wellbore using multiple barriers. A single-run multiple barrier system may be deployed in a wellbore to position a first barrier at a first depth and a second barrier at second depth above the first barrier in the wellbore during a

(57) **Abrégé(suite)/Abstract(continued):**

single run of a wellbore tubular string. The first barrier is coupled to a first running tool. A wellbore tubular string segment couples the first running tool is coupled to the second barrier. The second barrier is coupled to a second running tool that couples to the wellbore tubular string. The second barrier is locked until the first barrier is independently set at the first depth to prevent the second barrier from being set until the second depth is reached. Setting both barriers in a single run increases efficiency in an operation including reducing costs and time for completion of the operation.

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(54) Title: SETTING MECHANICAL BARRIERS IN A SINGLE RUN

(57) Abstract: An operation may require isolation of a wellbore using multiple barriers. A single-run multiple barrier system may be deployed in a wellbore to position a first barrier at a first depth and a second barrier at second depth above the first barrier in the wellbore during a single run of a wellbore tubular string. The first barrier is coupled to a first running tool. A wellbore tubular string segment couples the first running tool is coupled to the second barrier. The second barrier is coupled to a second running tool that couples to the wellbore tubular string. The second barrier is locked until the first barrier is independently set at the first depth to prevent the second barrier from being set until the second depth is reached. Setting both barriers in a single run increases efficiency in an operation including reducing costs and time for completion of the operation.

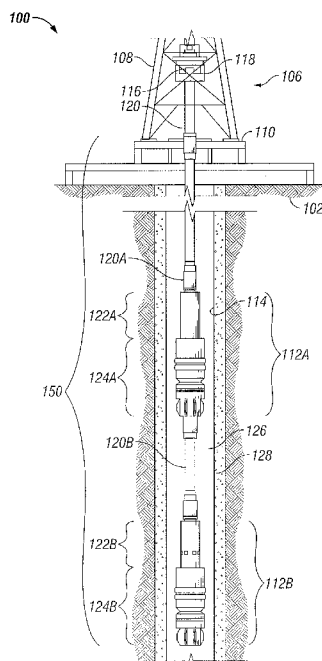


FIG. 1

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SETTING MECHANICAL BARRIERS IN A SINGLE RUN

TECHNICAL FIELD OF THE INVENTION

[0001] The present invention relates to setting barriers, and more particularly, to setting multiple barriers at two or more different depths in a single run in a wellbore.

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BACKGROUND

[0002] A wide variety of downhole tools, such as service tools, may be used within a wellbore in connection with the production of hydrocarbons and reworking or servicing a well. In many circumstances an operation may require that multiple barriers be introduced into a borehole or wellbore and set at different depths within the wellbore to isolate portions of the wellbore or the formation. Many operators and government regulations require that a minimum of two barriers be installed in a wellbore. For example, several types of operations for a job, including plug and abandonment and blow-out prevention for a hydrocarbon production, exploration and recovery site, may be implemented that require that multiple barriers be installed in the wellbore. Typically, each barrier must be separately run on a tool string, such as drill pipe or tubing string, into the wellbore and may require a different tool to unlock and set the barrier. As an example, a first barrier may be run into the wellbore with a tool string to a setting depth, set and the tool string is tripped out of the wellbore. The second barrier is connected to the tool string, run in the wellbore and set at a different setting depth and the tool string tripped back out of the well. Each installation of the barriers requires at least two trips down the wellbore which increases wear and tear on equipment and increases risk of mechanical failure both of which contribute to an increase in overall job completion time and costs for the overall job as well as increasing risks to the safety of nearby personnel.

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BRIEF DESCRIPTION OF THE DRAWINGS

[0003] FIG. 1 is a cross-sectional view of a single-run multiple barrier system in an operating environment, according to one or more aspects of the present disclosure.

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[0004] FIG. 2 is a cross-sectional view of a single-run multiple barrier system with the deep set barrier set in an operating environment, according to one or more aspects of the present disclosure.

[0005] FIG. 3 is a cross-sectional view of a single-run multiple barrier system with the shallow set barrier set in an operating environment, according to one or more aspects of the present disclosure.

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[0006] FIG. 4A is a schematic view of a shallow set barrier of a single-run multiple barrier system in an unset position, according to one or more aspects of the present disclosure.

[0007] FIG. 4B is a schematic view of a shallow set barrier of a single-run multiple barrier system in a set position, according to one or more aspects of the present disclosure.

5 [0008] FIG. 5A is a schematic view of a deep set barrier of a single-run multiple barrier system in an unset position, according to one or more aspects of the present disclosure.

[0009] FIG. 5B is a schematic view of a deep set barrier of a single-run multiple barrier system in a set position, according to one or more aspects of the present disclosure.

10 [0010] FIG. 6A is a cross-sectional view of a locking slot assembly for a shallow set barrier system in a locked position, according to one or more aspects of the present disclosure.

[0011] FIG. 6B is a cross-sectional view of a locking slot assembly for a shallow set barrier system in an unlocked position, according to one or more aspects of the present disclosure.

15 [0012] FIG. 7A is a cross-sectional view of a locking slot assembly for a shallow set barrier in a locked position, according to one or more aspects of the present disclosure.

[0013] FIG. 7B is a cross-sectional view of a locking slot assembly for a shallow set barrier in an unlocked position, according to one or more aspects of the present disclosure.

[0014] FIG. 8A is a side view of a locking slot assembly for a shallow set barrier in a locked position, according to one or more aspects of the present disclosure.

20 [0015] FIG. 8B is a side view of a locking slot assembly for a shallow set barrier in an unlocked position, according to one or more aspects of the present disclosure.

[0016] FIG. 9 is a schematic side view of a mandrel component and slide lock component of a deep set barrier system, according to one or more aspects of the present disclosure.

25 [0017] FIG. 10 is a schematic, cross-sectional side view of a top adapter and an overshoot component of a deep set barrier system, according to one or more aspects of the present disclosure.

[0018] FIG. 11 is a schematic side view, partially in cross-section, of a deep set barrier system in a locked configuration, according to one or more aspects of the present disclosure.

[0019] FIG. 12 is a schematic side view, partially in cross-section, of a deep set barrier system in a connected and locked configuration, according to one or more aspects of the present disclosure.

[0020] FIG. 13 is a schematic side view, partially in cross-section, of a deep set barrier system in a connected and unlocked configuration, according to one or more aspects of the present disclosure.

[0021] FIG. 14 is a schematic side view, partially in cross-section, of a deep set barrier system in a released and unlocked configuration.

[0022] FIG. 15 is a schematic side view, partially in cross-section, of a deep set barrier system in a released configuration.

[0023] FIG. 16 is a schematic side view, partially in cross-section, of the deep set barrier system in a released configuration.

[0024] FIG. 17 is a flowchart illustrating a method for setting a single-run multiple barrier system, according to one or more aspects of the present disclosure.

DETAILED DESCRIPTION

[0025] In the drawings and description that follow, like parts are typically marked with the same reference numerals. Specific embodiments are described and are shown in the drawings with the understanding that the present disclosure is to be considered an exemplification of the principles of the invention and is not intended to limit the invention that illustrated and described herein. It is to be fully recognized that the different teachings of the embodiments discussed throughout may be employed separately or in any suitable combination to produce desired results.

[0026] For certain downhole operations, barriers or isolation devices are required to be run in the wellbore to isolate portions of the wellbore or the formation. For example, blow-out prevention (BOP) or abandonment of a well may require that multiple barriers are run in the wellbore to isolate portions of the wellbore or the formation. Generally, for barriers deployed on a downhole tool, once one barrier is set, all barriers attached to tubing string or wellbore tubular string are set. An operation that requires setting multiple barriers at different depths requires

multiple runs in the wellbore. For example, a downhole tool comprising a barrier is ran in the wellbore to a specified depth and when the depth is reached the barrier is set. The downhole tool is retrieved and another barrier is ran in the wellbore on the same or different downhole tool. Again, once the specified depth is reached the barrier is set and the downhole tool is retrieved. As multiple runs are required for the setting of multiple barriers, the placement of multiple barriers at different depths requires significant time which increases the overall costs of an operation as well as increases the risk to nearby personnel due to multiple instances of contact with the equipment.

[0027] The present invention provides increased efficiency for a downhole operation that requires that multiple barriers or isolation devices be set in a wellbore to isolate portions of the wellbore or the formation. Providing a single-run multiple barrier system with multiple barriers that may be set in a wellbore using a single-run of a downhole tool alleviates the need for multiple runs. Setting multiple barriers in a single-run decreases wear and tear on equipment, reduces time for completion of the operation and increases safety by minimizing contact by nearby personnel to the required equipment. For example, a deep set barrier may be connected to a retrieval tool which is connected to a shallow set barrier that is also connected to a retrieval tool of a downhole tool. Both the deep set barrier and the shallow set barrier may be deployed downhole in a single run as the shallow set barrier is locked out until after the deep set barrier has been set.

[0028] FIG. 1 is a cross-sectional view of a single-run multiple barrier system 150 in an operating environment 100, according to one or more aspects of the present disclosure. The operating environment 100 comprises a workover or drilling rig 106 (generally referred to herein as rig 106) positioned at, on or about a surface 104. The rig 106 extends over and around a wellbore 114 that penetrates a subterranean formation 102. For example, rig 106 may be positioned and equipped for the discovery, exploration, production or any combination thereof of hydrocarbons. In one or more embodiments, rig 106 may be positioned and equipped for completion or abandonment (or both) or BOP of the wellbore 114. The wellbore 114 may extend into the subterranean formation 102 at any angle or deviation from the surface 104.

[0029] The rig 106 may comprise a derrick 108 and a rig floor 110 through which a wellbore tubular string extends downward from the drilling rig 106 into the wellbore 114. The rig 106 may comprise a motor 116 that drives a mechanism 118. Mechanism 118 may comprise a winch, a drum, a crank or any other device suitable for deploying and retrieving wellbore tubular string 120 in and out of wellbore 114. In one or more embodiments, the wellbore 114

may comprise a casing 128 or any other liner that extends the length of the wellbore 114 to form an annulus 126.

[0030] Wellbore tubular string 120 may comprise one or more sections including, but not limited to, one or more portions such as wellbore tubular string segment 120A and wellbore tubular string segment 120B. Wellbore tubular string 120 may comprise a drill pipe, tool string, tubing string, work string, tubing, drill string or any other piping that is coupled together to deploy one or more downhole tools within the wellbore 114, for example, single-run multiple barrier system 150. In one or more embodiments, the single-run multiple barrier system 150 is deployed in an annulus 126. Wellbore tubular string segment 120A may couple to a single-run multiple barrier system 150. Wellbore tubular string 120 may comprise any number of portions, segments or lengths coupled together to form wellbore tubular string 120. Any number of downhole tools may be coupled to wellbore tubular string 120. Wellbore tubular string 120 deploys the single-run multiple barrier system 150 to the required depth in the wellbore 114. For example, wellbore tubular string segment 120A may couple to one or more other segments of wellbore tubular string 120 and wellbore tubular string segment 120B may couple to one or more other segments of wellbore tubular string 120. Any one or more segments of wellbore tubular string 120 may be threaded or coupled to any one or more other segments of wellbore tubular string 120, one or more single-run multiple barrier systems 150, one or more other downhole tools or any combination thereof.

[0031] In one or more embodiments, single-run multiple barrier system 150 may comprise a deep set barrier system 112B at a distal end of the wellbore tubular string 120 and a shallow set barrier system 112A above the deep set barrier system 112B (collectively referred to as barrier systems 112), wellbore tubular string segment 120A and wellbore tubular string segment 120B. In one or more embodiments, single-run multiple barrier system 150 may comprise any number of barrier systems 112. While a single wellbore tubular string segment 120A and a single wellbore tubular string segment 120B are illustrated in FIG. 1, the present disclosure contemplates any number of wellbore tubular string segments 120A and 120B. Shallow set barrier system 112A comprises a running tool 122A and an isolation device 124A, for example, a shallow set barrier. Deep set barrier system 112B comprises a running tool 122B and an isolation device 124B, for example a deep set barrier. In one or more embodiments, isolation devices 124A and 124B may comprise a bridge plug, a packer, a barrier valve or any other isolation device. In one or more embodiments, wellbore tubular string segment 120A couples to a running tool 122A and wellbore tubular string segment 120B couples to a running tool 122B and shallow set barrier system 112A, where running tools 122A and 122B are

collectively referred to as running tools 122. Running tool 122A couples to an isolation device 124A and running tool 122B couples to an isolation device 124B, where isolation devices 124A and 124B are collectively referred to as isolation devices 124. Wellbore tubular string segment 120B couples the isolation device 124A to the running tool 122B.

5 [0032] FIG. 2 is a cross-sectional view of a single-run multiple barrier system 150 with a deep set barrier system 112B set in an operating environment 200, according to one or more aspects of the present disclosure. Operating environment 200 is similar to operating environment 100 except that the deep set barrier system 112B has been disengaged from wellbore tubular string segment 120B or set at the required, specified or selected depth in
10 wellbore 114.

[0033] FIG. 3 is cross-sectional view of a single-run multiple barrier system 150 with the shallow set barrier system 112A set in an operating environment 300, according to one or more aspects of the present disclosure. Operating environment 300 is similar to operating environments 100 and 200 except that the shallow set barrier system 112A has been disengaged
15 from wellbore tubular string segment 120A or set at the required, specified or selected depth in wellbore 114.

[0034] While the operating environment depicted in FIGS. 1-3 refer to a stationary rig 106 for conveying the wellbore tubular string 120 comprising the single-run multiple barrier system 150 within a land-based wellbore 114, in alternative embodiments, mobile workover rigs,
20 wellbore servicing units (such as coiled tubing units), and the like may be used to convey the wellbore tubular string 120 comprising the single-run multiple barrier system 150 within the wellbore 114. It should be understood that a wellbore tubular string 120 comprising the single-run multiple barrier system 150 may alternatively be used in other operating environments, such as within an offshore wellbore operating environment. For example, workover or drilling rig
25 106 may be located offshore and wellbore 114 may be a subsea wellbore.

[0035] FIG. 4A is a schematic view of a shallow set barrier or isolation device 124A of a single-run multiple barrier system, such as single-run multiple barrier system 150, in an unset position according to one or more aspects of the present disclosure. The isolation device 124A is shown disposed or positioned in an annulus 126 formed by casing 128 in wellbore 114. In one
30 or more embodiments, isolation device 124A may be disposed or positioned in an uncased wellbore 114. The shallow set barrier system 112A may comprise an isolation device 124A. In one or more embodiments, isolation device 124A may comprise any one or more of a top

connector 402A a bottom connector 402B, a rupture disk 412, a rubber element 410, an anchor 406 and a centralizer 404. In one or more embodiments, any one or more of a top connector 402A, a bottom connector 402B, a rupture disk 412, a rubber element 410, an anchor 406 and a centralizer 404 may couple to the isolation device 124A directly or indirectly. Top connector 402A couples the isolation device 124A to running tool 122A. Bottom connector 402B couples the isolation device 124A to one or more wellbore tubular segments 120, a downhole tool or any other device. One or more anchors 406 may comprise or couple to one or more projections 408. Centralizer 404 aids in maintaining positioning of the isolation device 124A in the annulus 126.

[0036] FIG. 4B is a schematic view of a shallow set barrier or isolation device 124A of a single-run multiple barrier system, such as single-run multiple barrier system 150, in a set position, according to one or more aspects of the present disclosure. FIG. 4B is similar to FIG. 4A except that the rupture disk 412 in FIG. 4A has ruptured to set the isolation device 124A. One or more anchors 408 are actuated such that one or more projections 408 secure the isolation device 124A to the casing 128 in the wellbore 114. In one or more embodiments, once the required depth is reached, the one or more projections 408 of the one or more anchors 406 may be extended to contact or couple to the wellbore 114, annulus 126, casing 128, any other structure within wellbore 114 or any combination thereof to secure the isolation device 124A to the wellbore 114. The rubber element 410 is compressed to form a seal against the casing 128 to isolate a portion of the annulus 126. For example, the portion of the annulus 126 below rubber element 410 is isolated from fluid flow from above the rubber element 410 and the portion of the annulus 126 above the rubber element is isolated from fluid flow from below the rubber element 410. The isolation device 124A may be set according to any one or more embodiments described below with respect to FIGS. 6A-8B.

[0037] FIG. 5A is a schematic view of a deep set barrier or isolation device 124B of a single-run multiple barrier system, such as single-run multiple barrier system 150, in an unset position, according to one or more aspects of the present disclosure. The isolation device 124B is shown disposed or positioned in an annulus 126 formed by casing 128 in wellbore 114. In one or more embodiments, isolation device 124B may be disposed or positioned in an uncased wellbore 114. In one or more embodiments, isolation device 124B may comprise any one or more of a top connector 502A, a bottom connector 502B, a running tool 122B, a rubber element 510, an anchor 506 and a centralizer 504. In one or more embodiments, any one or more of a top connector 502A, a bottom connector 502B, a running tool 122B, a rubber element 510, an anchor 506 and a centralizer 504 may couple directly or indirectly to the isolation device 124B. Top connector 502A is similar to top connector 402A of FIG. 4A. Top connector 504A couples the

isolation device 124B to running tool 122B. Bottom connector 504B couples the isolation device 124B to one or more wellbore tubular strings 120, a downhole tool or another device or terminates the isolation device 124B. One or more anchors 506 may comprise or couple to one or more projections 508 similar to the one or more anchors 406 and one or more projections 408 of FIG. 3A. Centralizer 504 is similar to centralizer 404 of FIG. 4A and aids in maintaining position of the isolation device 124B in the annulus 126.

[0038] FIG. 5B is a schematic view of a deep set barrier or isolation device 124B of a single-run multiple barrier system, such as single-run multiple barrier system 150, in a set position, according to one or more aspects of the present disclosure. FIG. 5B is similar to FIG. 5A except that the isolation device 124B is in the set position. In one or more embodiments, once the required depth is reached, the one or more projections 508 of the one or more anchors 506 may be extended to contact or couple to the wellbore 114, annulus 126, casing 128 or any combination thereof. The rubber element 510 is compressed to form a seal against the casing 128 to isolate a portion of the annulus 126 as discussed above with respect to FIG. 4B. Isolation device 124B may be set according to any one or more embodiments described below with respect to FIGS. 9 and 10.

[0039] With respect to FIGS. 6A and 6B, the locking slot assembly of the present invention is shown and generally designated by the numeral 610. FIG. 6A is a cross-sectional view of a locking assembly 610 for a shallow set barrier system 112A in a locked position, according to one or more aspect of the present disclosure. FIG. 6B is a cross-sectional view of a locking assembly 610 in an unlocked position, according to one or more aspects of the present disclosure. Locking assembly 610 is disposed adjacent to a lower end of a downhole tool (shown in FIG. 7A), for example, running tool 122A of FIGS. 1-3 and 4A. Shallow set barrier system 112A may connect to a tool string (not shown). For example, as illustrated in FIG 1, running tool 122A may connect to wellbore tubular string 120. The entire tool string or wellbore tubular string 120 may be positioned in a wellbore, for example, wellbore 114 of FIGS. 1-4B. The wellbore may be defined by a casing (not shown), such as casing 128 of FIGS. 1-4B, and may be vertical, horizontal or deviated to any degree.

[0040] Locking assembly 610 is illustrated at a distal end of the shallow set barrier system 112A. Shallow set barrier system 112A may include, or be attached to or otherwise coupled to, an inner, actuating mandrel 614, which may be connected or coupled to the wellbore tubular string 120. Locking assembly 610 may include the actuating mandrel 614, attached at a lower end to bottom adapter 616. Actuating mandrel 614 and at least a portion of bottom

adapter 616 may be situated within a fluid chamber case 618, a lock 620 or both. The fluid chamber case 618 and the lock 620 may be removably attached, fixedly attached, or even integrally formed with one another. Alternatively, fluid chamber case 618 and lock 620 may be separate.

5 [0041] At least one fluid chamber 622 may be situated between actuating mandrel 614 and lock 620. Fluid chamber 622 may be sealed via one or more seals 624, along with a rupture disk 626, such as rupture disk 412 of FIG. 4A, situated in the lock 620. Air at atmospheric pressure may initially fill the fluid chamber 622. As the shallow set barrier system 112A is lowered into the well bore, hydrostatic pressure outside the shallow set barrier system 112A increases. Once the hydrostatic pressure reaches a predetermined value, the rupture disk 626 may rupture. After the rupture disk 626 has ruptured, the fluid outside the shallow set barrier system 112A will enter the shallow set barrier system 112A through a port 628 formed therein. The resulting increased pressure within the fluid chamber 622 will cause the fluid chamber 622 to expand (as shown in FIG. 6B). This expansion causes the longitudinal movement of the lock 620 with respect to the actuating mandrel 614, thus “unlocking” the locking assembly 610. The locking assembly 610 is locked and unlocked independent of the slide lock 950 of the deep set barrier system 112B discussed below. FIGS. 8A and 8B, which will be discussed below, further show the locked position and unlocked position respectively.

20 [0042] Referring now to FIGS. 7A and 7B, shown therein is an alternate embodiment of the locking assembly 610. FIG. 7A is a cross-sectional view of a locking assembly 610 for a shallow set barrier system 112A in a locked position, according to one or more aspects of the present disclosure. FIG. 7B is a cross-sectional view of a locking assembly 610 for a shallow set barrier system 112A in an unlocked position, according to one or more aspects of the present disclosure. This embodiment has no rupture disk 626. Instead, one or more shear pins 630 to prevent the lock 620 from moving until adequate pressure is present. A spring 632 may be included to keep the locking assembly 610 in an unlocked position. While the spring 632 shown is a coil spring, the spring 632 may be any biasing member. Likewise, the shear pin 630 may be a screw, spring, or any other shearable member. Other than the use of a rupture disk 626, a spring 632, or both the embodiment of FIGS. 7A and 7B functions similarly to the embodiment of FIGS. 6A and 6B. An increase in pressure causes the lock 620 to move longitudinally with respect to the actuating mandrel 614, resulting in the unlocking of the locking assembly 610 (as shown in FIG. 7B).

[0043] FIG. 8A is a side view of a locking assembly 610 for a shallow set barrier system 112A in a locked position, according to one or more aspects of the present invention. FIG. 8B is a side view of a locking slot assembly for a shallow set barrier system 112A in an unlocked position, according to one or more aspects of the present disclosure. One or more lugs 634 may extend from a lug rotator ring 636 into a continuous slot 638 in a sleeve 640, thus providing locking assembly 610. As previously discussed, pressure may cause the lock 620 to become unlocked. In the locked position, a locking portion 642 of the lock 620 occupies space within the slot 638, keeping the lugs 634 in a run-in-hole position, and preventing the lugs 634 from moving relative to the slot 638. As the lock 620 moves downwardly because of increased pressure, the locking portion 642 moves out of the slot 638, allowing the lugs 634 to move relative to the slot 638 if there is an upward or downward force acting on the sleeve 640.

[0044] In the run-in-hole, locked position, the lock 620 is in an upward position, in which lugs 634 are engaged with locking portion 642 of the lock 620. As the tool string is lowered into well bore, the locking assembly 610 will remain in the locked position shown in FIGS. 6A, 7A, and 8A, with the lock 620 preventing relative longitudinal movement of the lug rotator ring 36 with respect to the sleeve 640.

[0045] Once pressure is applied and the locking assembly 610 is unlocked (as shown in FIGS. 6B, 7B, and 8B), the locking assembly 610 may be actuated, allowing the lug rotator ring 636 to move longitudinally with respect to the sleeve 640. In other words, the shallow set barrier system 112A may be set by pushing downward on the wellbore tubular string 120, running tool 122A or both, which lowers lug 634. While any type of slot 638 may be used, the embodiment shown uses a J-slot, and in particular, shows a continuous J-slot. Depending on the specific application and the type of slot, setting the tool may involve pushing downward on the wellbore tubular string 120 multiple times. Thus, when a continuous J-slot is used, running tool 122A may be set by up and down motion alone. This may prevent the operator from cycling through the slot and setting shallow set barrier system 112A prematurely.

[0046] For retrieval, the tool string or wellbore tubular string 120 is simply pulled upwardly out of the wellbore 114. This will cause the lug 634 to re-engage the slot 638. Additionally, as the pressure outside the shallow set barrier system 112A, and thus, the pressure within the fluid chamber 622 is reduced, the lock 620 may move back into the locked position, preventing any subsequent relative movement of the lug rotator ring 636 with respect to the sleeve 640.

[0047] While the application of pressure is disclosed above as one triggering event to allow the lug 634 to move within the slot 638, other events may also occur to allow the lug 634 to move within the slot 638. In this case, the lock 620 may be configured to allow the lug 634 to move within the slot after the triggering event has occurred, so long as a predetermined condition is maintained. For example, but not by way of limitation, the triggering event may be a timer reaching a predetermined value, and the predetermined condition may be that the timer has not yet reached a second predetermined value.

[0048] FIG. 9 is a schematic side view of a mandrel component and a slide lock component of a barrier system, for example, deep set barrier system 112B of FIGS. 1-3, according to one or more aspects of the present disclosure. The deep set barrier system 112B may comprise a mechanical locking system 902. In one or more embodiments, the deep set barrier system 112B may comprise a mandrel extension 920, a mandrel 930, a slide lock 950, a spring mandrel 960, and a spring housing 980 where the top adapter 910 and overshoot 940 as illustrated in FIG. 10 are removed. The mandrel 930 may include one or more sets 938 of external lugs 935 spaced circumferentially about the mandrel 930. In one embodiment, the mandrel 930 comprises four (4) sets 938 of external lugs 935, spaced at 90-degree intervals circumferentially about the mandrel 930, and each set 938 comprises ten (10) longitudinally spaced external lugs 935.

[0049] FIG. 10 is a schematic, cross-sectional side view of a top adapter 910 and an overshoot 940 component of a deep set barrier system 112B, according to one or more aspects of the present invention. The top adapter 910 and the overshoot 940 are disconnected from the remaining components of the deep set barrier system 112B. The overshoot 940 includes one or more sets 948 of internal lugs 945 spaced apart circumferentially about the overshoot 940. In an embodiment, the number and location of the internal lugs 945 on the overshoot 940 corresponds directly to the number and location of the external lugs 935 on the mandrel 930. However, in other embodiments, a different number of internal lugs 945 and external lugs 935 may be provided, so long as the lugs 945, 935 interact to form a releasable connection.

[0050] Further, the internal lugs 945 and the external lugs 935 are adapted to engage as to support weight below the releasable connection. The size and number of engaging lugs 945, 935, and more specifically, the total cross-sectional area of engagement of the lugs 945, 935, determines the quantity of weight that can be supported by the deep set barrier system 112B, including, but not limited to, the running tool 122B. In one embodiment, four (4) sets 948, 938 of ten (10) lugs 945, 935 are provided on the overshoot 940 and the

mandrel 930 respectively; the sets 948, 938 are spaced apart at 90-degree intervals circumferentially; the lugs 945, 935 are each approximately 1/2-inch wide and 1/4-inch high; and the deep set barrier system 112B is adapted to support several hundred tons of weight, for example, 500 tons of weight. Assuming the same size of engaging lugs 945, 935, the amount of weight that can be supported by the deep set barrier system 112B changes linearly with the quantity of lugs 945, 935 provided. For example, if the embodiment described above included only half as many lugs 945, 935, the deep set barrier system 112B would be adapted to support 250 tons of weight, and if the embodiment described above included twice as many lugs 945, 935, the deep set barrier system 112B would be adapted to support 1,000 tons of weight. Similarly, assuming the same quantity of engaging lugs 945, 935, the amount of weight that can be supported by the device 100 changes linearly with the size of the lugs 945, 935 provided. For example, if the embodiment described above included the same quantity of lugs 945, 935 but the lugs 945, 935 were only half the size, the device 100 would be adapted to support 250 tons of weight, and if the embodiment described above included the same quantity of lugs 945, 935 but the lugs 945, 935 were twice the size, the deep set barrier system 112B would be adapted to support 1,000 tons of weight.

[0051] As best depicted in FIG. 9 and FIG. 10, to aid with alignment of the overshoot 940 as it is being lowered over the mandrel 930 for retrieval of the deep set barrier system 112B from the wellbore 114, at least one set 938 of external lugs 935 comprises a tapered upper surface 936 on the uppermost external lug 935. This tapered upper surface 936 corresponds to the shape of at least one angled alignment key 949 on the overshoot 940. Thus, the interaction between the tapered upper surface 936 on the uppermost external lug 935 and the angled alignment key 949 guides the overshoot 940 into proper alignment so that the overshoot 940 can further be lowered over the mandrel 930.

[0052] Referring again to FIG. 9, in an embodiment, the mandrel 930 further comprises one or more J-slots 937 configured to receive at least one angled guide key 947 on the overshoot 940 as the overshoot 940 is being lowered over the mandrel 930. The J-slot 937 is shown partially covered by the slide lock 950 in FIG. 2. The interaction between the J-slots 937 and the angled guide keys 947 imparts a rotation of less than 360 degrees in a first direction to the overshoot 940 as it is being lowered longitudinally over the stationary mandrel 930. In the embodiments shown herein, the interaction between the J-slots 937 and the angled guide keys 947 imparts a maximum of a 90-degree rotation to the overshoot 940. Such rotation causes the internal lugs 945 and the external lugs 935 to interact to form a releasable connection with the wellbore tubular string 120. Thus, the J-slots 937 act as rotational guide slots. In addition,

the J-slots 937 may comprise V-shaped entrances 939 corresponding to the shape of the angled guide keys 947, thereby facilitating entry of the guide keys 947 into the J-slots 937. In another embodiment of the deep set barrier system 112B, the mandrel 930 does not include J-slots 937. In this embodiment, the overshot 940 is lowered to a known position with respect to the mandrel 930, such as by engaging a shoulder, and then the overshot 40 is rotated less than 360 degrees in a first direction with respect to the mandrel 930.

[0053] To disengage the internal lugs 945 from the external lugs 935, a 45-degree rotation opposite of the first direction is applied to the wellbore tubular string 120 from the surface of the wellbore 114, thereby rotating the overshot 940 with respect to the mandrel 930. To ensure that the overshot 940 is not over-rotated with respect to the mandrel 930 during release, the mandrel 930 may comprise a rotational stop 934 that extends between at least two of the external lugs 935 to act as a barrier for preventing the internal lugs 945 from reconnecting and reengaging with the external lugs 935.

[0054] FIG. 11 is a partial schematic side view, partially in cross-section, of a deep set barrier system 112B in a locked configuration, according to one or more aspects of the present disclosure. Referring first to the run-in operating sequence, FIG. 11 depicts the deep set barrier system 112B in a connected, locked, and weight-supporting configuration. In particular, the internal lugs 945 on the overshot 940 and the external lugs 935 on the mandrel 930 are shown interacting to form a releasable connection, and the upper surfaces 943 of the internal lugs 945 are shouldered against the lower surfaces 993 of the external lugs 935, thereby reflecting that the deep set barrier system 112B is supporting weight. Further, a guide key 947 on the overshot 940 is shown disposed within a J-slot 937 on the mandrel 930, and the slide lock 950 is in its uppermost, locked position, covering a portion of the J-slot 937. The slide lock 950 is biased to the locked position by a spring 970 disposed in the spring cavity 975 within the spring housing 980. In this locked position, the slide lock 950 prevents disconnection of the overshot 940 from the mandrel 930 during run-in.

[0055] FIG. 12, is a partial schematic side view, partially in cross-section, of a deep set barrier system 112B in a connected and locked configuration, according to one or more aspects of the present disclosure. Once the deep set barrier system, for example, deep set barrier system 112B, is lowered to the specified, required, selected or desired depth, a deep set depth, force may be applied from the surface 104 through the wellbore tubular string 120 to manipulate the deep set barrier system 112B and particularly the isolation device 124B. FIG. 5 depicts the deep set barrier system 112B positioned to transfer force from the wellbore tubular string 120B to the

isolation device 124B. As force is applied through the wellbore tubular string 120, the overshot 940 is forced downwardly with respect to the mandrel 930 until the lower surfaces 946 of the internal lugs 945 are shouldered against the upper surfaces 996 of the external lugs 935, thereby transferring force to the isolation device 124B. As shown in FIG. 12, the guide key 947 on the overshot 940 has moved downwardly within the J-slot 937 on the mandrel 930, but the slide lock 950 is still biased by the spring 970 to its uppermost, locked position.

[0056] FIGS. 13-16 depict the sequence for unlocking the deep set barrier system 112B and rotating the overshot 940 by less than 360 degrees opposite of the first direction with respect to the mandrel 930 to allow removal of the top adapter 910 and overshot 940 from the wellbore 114. Referring first to FIG. 13 which is a partial schematic side view, partially in cross-section, of a deep set barrier system 112B in a connected and unlocked configuration, according to one or more aspects of the present disclosure. After the one or more isolation devices 124B have been manipulated and set in the wellbore 114, the slide lock 950 may be forced downwardly to unlock the deep set barrier system 112B by applying a differential pressure across the slide lock 950 against biasing spring 970. As there is no fluid flowing through the flow bore 990 in the deep set barrier system 112B, a differential pressure can be applied across the slide lock 950 against the spring 970 by pressuring up the annulus 126 formed between the deep set barrier system 112B and the casing 128. When no pressure is applied to the annulus 126, the spring 970 expands to bias the slide lock 950 upwardly to the locked position. However, because the spring chamber 975 is in fluid communication with the device flow bore 990 via ports 965 in the spring mandrel 960, once pressure is applied to the annulus 126, a differential pressure is created across the slide lock 950, thereby allowing the slide lock 950 to overcome the bias of the spring 970 and move downwardly to the unlocked position shown in FIG. 13 wherein the J-slot 937 is fully visible. Thus, in one embodiment, the slide lock 950 is biased to respond to pressure in the annulus 126.

[0057] In another embodiment, the slide lock 950 may be biased to respond to differential pressure created by applying pressure to the flow bore 990 rather than applying pressure to the annulus 126. Again, because the spring chamber 975 is in fluid communication with the flow bore 990 via ports 965 in the spring mandrel 960, by pressuring up the fluid within the flow bore 990, a differential pressure is created across the slide lock 950, thereby allowing the slide lock 950 to overcome the bias of the spring 970 and move downwardly to the unlocked position shown in FIG. 13. Thus, in the alternative embodiment, the slide lock 940 is biased to respond to tubing pressure.

[0058] Once the deep set barrier system 112B is unlocked, and with the lower surface 946 of the internal lugs 945 shouldered against the upper surface 996 of the external lugs 935, an opposite rotation may be applied to the wellbore tubular string 120, thereby causing the top adapter 910 and overshot 940 to rotate opposite of the first direction with respect to the mandrel 930. The rotation will be less than 360 degrees, and in the embodiments depicted herein where four (4) interacting sets of lugs 938, 948 are positioned 90 degrees apart circumferentially, the rotation will be 45 degrees. As shown in FIG. 14, as this 45-degree opposite rotation is applied, the internal lugs 945 disengage from and move out of alignment with the external lugs 935 to a released position. Further, as the opposite rotation is applied, the rotational stop 934 will provide a barrier to prevent reconnection of the internal lugs 945 with the external lugs 935.

[0059] Once the overshot 940 is released from the mandrel 930, the top adapter 910 and the overshot 940 are removable from the remaining components of the deep set barrier system 112B as shown in FIG. 15. After the top adapter 910 and overshot 940 are removed, the mandrel extension 920, the mandrel 930, the slide lock 950, the spring mandrel 960, the spring 970, and the spring housing 980 are still connected to the isolation device 124B within the wellbore 114 as shown in FIG. 16.

[0060] FIGS. 11-16, when viewed in reverse order, also depict a retrieval operating sequence for the deep set barrier system 112B, wherein the top adapter 910 and the overshot 940 are run back into the wellbore 114 to reconnect with the mandrel 930 to withdraw the deep set barrier system 112B including the isolation device 124B and running tool 122B from the wellbore 114. Referring first to FIG. 16, a partial schematic side view, partially in cross-section, of the deep set barrier system 112B comprising the mandrel extension 920, the mandrel 930, the slide lock 950, the spring mandrel 960, the spring 970, and the spring housing 980 are shown connected to the isolation device 124B within the wellbore 114. The slide lock 950 moved upwardly over the J-slot 937 in response to the spring 970 force since pressure was removed from the annulus 126.

[0061] FIG. 15 is a partial schematic side view, partially in cross-section, of a deep set barrier system 112B in a released configuration. As the top adapter 910 and overshot 940 are lowered over the mandrel extension 920 and mandrel 930, the angled alignment key 949 on the overshot 940 will engage the upper tapered surface 936 of the external lugs 935 on the mandrel 930. This engagement will cause the overshot 940 to rotate into proper alignment with the mandrel 390 so that the sets 948 of internal lugs 945 will fit between the sets 938 of external

lugs 935 as the overshoot 940 continues moving downwardly. Therefore, regardless of the position of the overshoot 940 as it is being run into the wellbore 114, the upper tapered surface 936 on the external lugs 935 will interact with the angles on the alignment key 949 to properly align the overshoot 940 with respect to the mandrel 930.

5 [0062] Further, in an embodiment, the alignment key 949 has a longitudinal length that exceeds the distance between two of the lugs 935 on the mandrel 930. Therefore, because the angled alignment key 949 will not fit between two lugs 935 on the mandrel 930, the overshoot 940 and mandrel 390 cannot form a partial connection. Instead, the overshoot 940 must be lowered completely over the mandrel 930 so that when the overshoot 940 is rotated to form the
10 releasable connection, the sets 948 of lugs 945 on the overshoot 940 and the sets 938 of lugs 935 on the mandrel 930 are fully engaged, and the angled alignment key 949 is positioned below the lowermost mandrel lug 935.

[0063] Referring now to FIG. 14, as the overshoot 940 continues to be lowered with respect to the mandrel 930, the angled guide key 947 will extend into the J-slot 937 via the V-
15 shaped opening 939 while mechanically engaging a tapered upper surface 952 on the slide lock 50, thereby forcing the slide lock 950 downwardly to an unlocked position against the force of the spring 970. Thus, when reconnecting the overshoot 940 to the mandrel 930, no pressure is required to be applied to the annulus 126 or to the flow bore 990 to cause the slide lock 950 to move downwardly against the spring 970 in response to differential pressure. Instead, only the
20 mechanical force of the angled guide key 947 acting on the tapered upper surface 952 of the slide lock 950 is required. In an alternative embodiment, the slide lock 950 may be actuated electromechanically, such as by using a downhole motor to retract the slide lock 950 in response to a tripped switch, for example.

[0064] As the overshoot 940 continues moving downwardly in a longitudinal direction,
25 the guide key 947 traverses the J-slot 937, and the angled shape of the J-slot 937 will thereby impart a maximum 990-degree rotation in the first direction to the overshoot 940. As shown in FIG. 13, as the guide key 947 moves toward the lowermost point in the J-slot 937, the internal lugs 945 of the overshoot 940 are rotated to interact with and engage the external lugs 935 on the mandrel 930. Once the guide key 947 is no longer engaging the slide lock 950 to mechanically
30 force it down, the slide lock 950 will return to the uppermost, locked position shown in FIG.12, in response to the bias force of the spring 970.

[0065] The running tool 122B is now reconnected and locked so that the isolation device 124B can be retrieved from the wellbore 114. When the deep set barrier system 112B is in the configuration shown in FIG. 12, the isolation device 124B may be released from the casing 128, thereby transferring weight to the interacting and engaging lugs 945, 935. This will allow the
5 overshot 940 to be raised up with respect to the mandrel 930 so that the upper surface 943 of the internal lugs 945 shoulder against the lower surface 993 of the external lugs 935 as shown in FIG. 11. Still referring to FIG. 11, when the deep set barrier system 112B is in a weight-supporting position, in one embodiment, the guide key 947 is positioned within a vertical portion of the J-slot 937 so that the guide key 947 does not support any weight. Thus, the guide
10 key 947 is not required to have the same strength as the lugs 935, 945. As shown in FIG. 11, the connected, locked, and weight-supporting deep set barrier system 112B is configured to retrieve the isolation device 124B from the wellbore 114.

[0066] Thus, deep set barrier system 112B comprises a releasable, weight-supporting connection via interacting and engaging lugs 935, 945 that can be designed to support large
15 quantities of weight, such as 500 tons, for example. Further, the deep set barrier system 112B facilitates easy release from an isolation device 124B, such as when operating from a floating offshore rig, because the lugs 935, 945 are disconnected via a 45-degree opposite rotation of the overshot 940 with respect to the mandrel 930. When reconnecting the lugs 935, 945, a 45-degree rotation in the first direction may be imparted automatically via a guide key 947 interacting with
20 a J-slot 937. The deep set barrier system 112B may further comprise several safety features, such as a slide lock 950 that requires multiple actions to open in the run-in position, thereby preventing inadvertent disconnection, an alignment key 949 having a length that prevents a partial connection between the lugs 945 of the overshot 940 and the lugs 935 of the mandrel 930, and a rotational stop 934 that prevents inadvertent re-connection during release of the
25 overshot 940 from the mandrel 930.

[0067] FIG. 17 is a flowchart illustrating a method for setting a single-run multiple barrier system, for example, single-run multiple barrier system 150 of FIGS. 1-3, according to one or more aspects of the present disclosure. At Step 1102, a single-run multiple barrier system 150 is deployed in a wellbore 114. As discussed with respect to FIG. 1, the single-run multiple
30 barrier system 150 may comprise multiple barrier systems 112, for example, shallow set barrier system 112A and deep set barrier system 112B. In one or more embodiments, a distal end of a wellbore tubular string 120 is coupled to the single-run multiple barrier system 150. In one or more embodiments, each component of the single-run multiple barrier system 150 is coupled to the wellbore tubular string 120 one by one as the wellbore tubular string 120 is ran in the

wellbore 114. For example, as wellbore tubular string 120 is lowered into the wellbore 114, a deep set barrier system 112B is coupled to wellbore tubular string segment 120B, wellbore tubular string segment 120B is coupled to shallow set barrier system 112A, shallow set barrier system 112A is coupled to wellbore tubular string segment 120A and wellbore tubular string segment 120A is coupled to one or more other segments of wellbore tubular string 120. The single-run multiple barrier system is initially deployed with the shallow set barrier system 112A and the deep set barrier system 112B in a locked configuration such that the isolation device 124A and the isolation device 124B are not inadvertently set during deployment of the single-run multiple barrier system 150 to a specified, required or desired depth in the wellbore 114. For example, the shallow set barrier system 112A may be locked as discussed above with respect to FIG. 6A, 7A and 8A and deep set barrier system 112B may be locked as discussed above with respect to FIG. 9 and FIG. 10. In one or more embodiments, the shallow set barrier system 112A comprises a hydraulic locking feature that prevents the isolation device 124A from being set until a specified hydrostatic pressure is reached at the specified shallow set depth while the deep set barrier system 112B comprises a mechanical locking system 902 that prevents the isolation device 124B from being set until the specific deep set depth has been reached.

[0068] At step 1106, it is determined if the setting depth for the deep set barrier system 112B has been reached. The setting depth may be based on one or more parameters of the formation 102, the wellbore 114 or any other parameter or combination thereof. The depth of each component of the single-run multiple barrier system 150 as it is deployed into the wellbore 114 may be determined by any one or more techniques for determining depth in a wellbore 114. For example, the length of each segment of wellbore tubular string 120 and any downhole tool attached to the wellbore tubular string may be known such that as the wellbore tubular string 120 is ran in the wellbore 114, the depth of the distal end of or any portion along the wellbore tubular string 120 is known

[0069] At step 1112, once the setting depth for the deep set barrier system 112B has been reached, deployment of the wellbore tubular string 120 is stopped or halted and the isolation device 124B (for example, the deep set barrier) is set. For example, actuation of motor 116 and winch 118 of FIG. 1 may be stopped, halted or suspended. As the shallow set barrier system 112A remains locked during deployment of the single-run multiple barrier system 150, the isolation device 124B may be set independently of the isolation device 124A. For example, the isolation device 124B may be set according to any one or more embodiments discussed above with respect to FIGS. 9 and 10 while the isolation device 124A remains locked as discussed above with respect to FIGS. 6A, 7A and 8A. In one or more embodiments, the isolation device

124B is mechanically set with rotation of the wellbore tubular string 120, up and down movement of the wellbore tubular string 120 or any other manipulation of the wellbore tubular string 120.

[0070] At step 1118, the deep set barrier system 112B is disconnected from the wellbore tubular string segment 120B. For example, running tool 122B may be disconnected from wellbore tubular string segment 120B as discussed below with respect to FIGS. 13-16. In one or more embodiments, the running tool 122B may be mechanically, hydraulically, or mechanically and hydraulically disconnected from the wellbore tubular string segment 120B.

[0071] At step 1124, once the deep set barrier system 112B has been disconnected from the wellbore tubular string 120, the wellbore tubular string 120 is retracted or picked up to dispose or position the shallow set barrier system 112A at a specified, determined, required or selected depth, a shallow set depth. For example, motor 116 and winch 118 of FIG. 1 may be actuated to pull, retrieve or retract one or more segments of the wellbore tubular string 120 from the wellbore 114.

[0072] At step 1130, it is determined if the setting depth for the shallow set barrier system has been reached. The setting depth may be based on one or more parameters of the formation 102, the wellbore 114 or any other parameter or combination thereof. The depth of each component of the single-run multiple barrier system 150 as it is retracted, retrieved, picked up or pulled from the wellbore 114 may be determined by any one or more techniques for determining depth in a wellbore as discussed above with respect to step 1106.

[0073] At step 1136, once the setting depth for the shallow set barrier system 112B has been reached, deployment of the wellbore tubular string 120 is halted or stopped and the isolation device 124A (for example, the shallow set barrier) is set. For example, actuation of motor 116 and winch 118 of FIG. 1 may be halted, stopped or suspended. In one or more embodiments, the isolation device 124A may be set according to any one or more embodiments discussed above with respect to FIGS. 6B, 7B and 8B. In one or more embodiments, the isolation device 124A is set by applying annulus pressure to the wellbore 114 which ruptures a disk, for example, rupture disk 412 of FIG. 4A or rupture disk 626 of FIG. 6A, to unlock a J-slot, for example, slot 638 of FIGS. 8A and 8B, to set the isolation device 124A as discussed above.

[0074] At step 1142, once the isolation device 124A has been set, the running tool 122A is disconnected from the wellbore tubular string segment 120A. For example, the running tool 122A may be disconnected from the wellbore tubular string segment 120A hydraulically,

mechanically, or both. In one or more embodiments, the shallow set barrier system 112A including the running tool 122A is disconnected from the wellbore tubular string segment 120A in a similar manner as discussed above with respect to the deep set barrier system 112B.

5 [0075] At step 1148, any remaining segments of the wellbore tubular string 120 are retracted, retrieved or tripped out of the wellbore 114. One or more other steps may be initiated once the wellbore tubular string 120 has been tripped out of the wellbore 114 to complete a given operation.

[0076] Therefore, the present invention is well adapted to attain the ends and advantages mentioned as well as those that are inherent therein. The particular embodiments disclosed above
10 are illustrative only, as the present invention may be modified and practiced in different but equivalent manners apparent to those skilled in the art having the benefit of the teachings herein. Furthermore, no limitations are intended to the details of construction or design herein shown, other than as described in the claims below. It is therefore evident that the particular illustrative
15 embodiments disclosed above may be altered or modified and all such variations are considered within the scope and spirit of the present invention. Also, the terms in the claims have their plain, ordinary meaning unless otherwise explicitly and clearly defined by the patentee.

[0077] In one or more embodiments, a method of setting a single-run multiple barrier system comprises deploying a single-run multiple barrier system on a wellbore tubular string in a wellbore of a formation, wherein the single-run multiple barrier system comprises a deep set
20 barrier system at a distal end of the wellbore tubular string and a shallow set barrier above the deep set barrier system, determining if a first depth in the wellbore has been reached by the single-run multiple barrier system, setting a first isolation device of the deep set barrier system, wherein the shallow set barrier system comprises a rupture disk that prevents a lug from moving
25 within a continuous j-slot to prevent setting of the shallow set barrier system during setting of the first isolation device, disconnecting the deep set barrier system from the wellbore tubular string, retrieving the wellbore tubular string to a second depth, setting a second isolation device of the shallow set barrier system, disconnecting the shallow set barrier system from the wellbore tubular string. In one or more embodiments, setting the second device comprises rupturing the
30 rupture disk, allowing the lug to move within the continuous j-slot and lifting upward and pushing downward on the wellbore tubular string. In one or more embodiments, the first isolation device is coupled to a first running tool, and wherein disconnecting the deep set barrier system from the wellbore tubular string comprises disengaging the first running tool from the wellbore tubular string. In one or more embodiments, the shallow set barrier system is coupled

to a second running tool, wherein the second running tool is coupled to the wellbore tubular string, and wherein disconnecting the shallow set barrier system from the wellbore tubular string comprises disengaging the second running tool from the wellbore tubular string. In one or more embodiments, the method further comprises extending one or more first projections of one or more first anchors of the deep set barrier system to contact at least one of the wellbore, an annulus disposed within the wellbore, and a casing disposed within the wellbore. In one or more embodiments, the method further comprises extending one or more second projections of one or more second anchors of the shallow set barrier system to contact at least one of the wellbore, an annulus disposed within the wellbore, and a casing disposed within the wellbore. In one or more embodiments, the method further comprises maintaining positioning of the first isolation device in an annulus of the wellbore via a first centralizer. In one or more embodiments, the method further comprises maintaining positioning of the second isolation device in an annulus of the wellbore via a second centralizer. In one or more embodiments, at least one of the first setting depth and the second setting depth is based on one or more parameters of the formation. In one or more embodiments, the method further comprises retrieving the wellbore tubular string from the wellbore.

[0078] In one or more embodiments, a single-run multiple barrier system comprises a deep set barrier system, wherein the deep set barrier system comprises a first isolation device and a first running tool, wherein the first running tool couples to a first portion of a wellbore tubular string, a shallow set barrier system, wherein the shallow set barrier system comprises a second isolation device and second running tool, wherein the second running tool couples to a second portion of a wellbore tubular string, and a locking assembly of the shallow set barrier system, wherein the locking assembly is locked and unlocked independent of the deep set barrier system. In one or more embodiments, the locking assembly comprises a rupture disk that prevents a lug from moving within a continuous j-slot to prevent setting of the shallow set barrier system during setting of the first isolation device. In one or more embodiments, the lug moves within the continuous j-slot when the rupture disk ruptures to set the second isolation device. In one or more embodiments, the deep set barrier system further comprises a first running tool coupled to the first isolation device and the wellbore tubular string and wherein the first running tool disconnects from the wellbore tubular string to set the first isolation device and reconnects with the wellbore tubular string to retrieve the first isolation device. In one or more embodiments, the shallow set barrier system further comprises a second running tool coupled to the second isolation device and the wellbore tubular string and wherein the second running tool disconnects from the wellbore tubular string to set the second isolation device and reconnects with the

wellbore tubular string to retrieve the second isolation device. In one or more embodiments, the deep set barrier system further comprises one or more first anchors and one or more first projections of the one or more first anchors, wherein the one or more first projections extend to contact at least one of the wellbore, an annulus disposed within the wellbore and a casing disposed within the wellbore. In one or more embodiments, the shallow set barrier system further comprises one or more second anchors and one or more second projections of the one or more second anchors, wherein the one or more second projections extend to contact at least one of the wellbore, an annulus disposed within the wellbore and a casing disposed within the wellbore. In one or more embodiments, the deep set barrier system further comprises a first centralizer. In one or more embodiments, the shallow set barrier system further comprises a second centralizer. In one or more embodiments the wellbore tubular string comprises a first wellbore tubular string segment coupled to the first running tool and the shallow set barrier system and a second wellbore tubular string segment coupled to the second running tool, wherein the first running tool disengages from the first wellbore tubular string segment to set the deep set barrier system, and wherein the second running tool disengages from the second wellbore tubular string segment to set the shallow set barrier system.

[0079] CLAIMS

What is claimed is:

1. A method of setting a single-run multiple barrier system comprising:

5 deploying a single-run multiple barrier system on a wellbore tubular string in a wellbore of a formation, wherein the single-run multiple barrier system comprises a deep set barrier system at a distal end of the wellbore tubular string and a shallow set barrier above the deep set barrier system;

 determining if a first depth in the wellbore has been reached by the single-run multiple barrier system;

10 setting a first isolation device of the deep set barrier system, wherein the shallow set barrier system comprises a rupture disk that prevents a lug from moving within a continuous j-slot to prevent setting of the shallow set barrier system during setting of the first isolation device;

 disconnecting the deep set barrier system from the wellbore tubular string;

15 retrieving the wellbore tubular string to a second depth;

 setting a second isolation device of the shallow set barrier system; and

 disconnecting the shallow set barrier system from the wellbore tubular string.

2. The method of claim 1, wherein setting the second device comprises:

 rupturing the rupture disk;

20 allowing the lug to move within the continuous j-slot; and

 lifting upward and pushing downward on the wellbore tubular string.

3. The method of any one or more of claims 1-2, wherein the first isolation device is coupled to a first running tool, and wherein disconnecting the deep set barrier system from the wellbore tubular string comprises disengaging the first running tool from the wellbore tubular string.
4. The method of any one or more of claims 1-3, wherein the shallow set barrier system is
5 coupled to a second running tool, wherein the second running tool is coupled to the wellbore tubular string, and wherein disconnecting the shallow set barrier system from the wellbore tubular string comprises disengaging the second running tool from the wellbore tubular string.
5. The method of any one or more of claims 1-4, further comprising: extending one or more
10 first projections of one or more first anchors of the deep set barrier system to contact at least one of the wellbore, an annulus disposed within the wellbore, and a casing disposed within the wellbore.
6. The method of any one or more of claims 1-5, further comprising: extending one or more second projections of one or more second anchors of the shallow set barrier system to contact
15 at least one of the wellbore, an annulus disposed within the wellbore, and a casing disposed within the wellbore.
7. The method of any one or more of claims 1-6, further comprising: maintaining positioning of the first isolation device in an annulus of the wellbore via a first centralizer.
8. The method of any one or more of claims 1-7, further comprising: maintaining positioning of
20 the second isolation device in an annulus of the wellbore via a second centralizer.
9. The method of any one or more of claims 1-8, wherein at least one of the first setting depth and the second setting depth is based on one or more parameters of the formation.

10. The method of any one or more of claims 1-9, further comprising: retrieving the wellbore tubular string from the wellbore.

11. A single-run multiple barrier system comprising:

5 a deep set barrier system, wherein the deep set barrier system comprises a first isolation device and a first running tool, wherein the first running tool couples to a first portion of a wellbore tubular string;

a shallow set barrier system, wherein the shallow set barrier system comprises a second isolation device and second running tool, wherein the second running tool couples to a second portion of a wellbore tubular string; and

10 a locking assembly of the shallow set barrier system, wherein the locking assembly is locked and unlocked independent of the deep set barrier system.

12. The single-run multiple barrier system of claim 11, wherein the locking assembly comprises a rupture disk that prevents a lug from moving within a continuous j-slot to prevent setting of the shallow set barrier system during setting of the first isolation device.

13. The single-run multiple barrier system of claim 12, wherein the lug moves within the continuous j-slot when the rupture disk ruptures to set the second isolation device.

14. The single-run multiple barrier system of claims 11-13, wherein the deep set barrier system further comprises:

20 a first running tool coupled to the first isolation device and the wellbore tubular string; and

wherein the first running tool disconnects from the wellbore tubular string to set the first isolation device and reconnects with the wellbore tubular string to retrieve the first isolation device.

15. The single-run multiple barrier system of claim 11-14, where the shallow set barrier system further comprises:

a second running tool coupled to the second isolation device and the wellbore tubular string; and

5 wherein the second running tool disconnects from the wellbore tubular string to set the second isolation device and reconnects with the wellbore tubular string to retrieve the second isolation device.

16. The single-run multiple barrier system of claim 11-15, wherein the deep set barrier system further comprises:

10 one or more first anchors; and

one or more first projections of the one or more first anchors, wherein the one or more first projections extend to contact at least one of the wellbore, an annulus disposed within the wellbore and a casing disposed within the wellbore.

15 17. The single-run multiple barrier system of claim 11-16, wherein the shallow set barrier system further comprises:

one or more second anchors; and

20 one or more second projections of the one or more second anchors, wherein the one or more second projections extend to contact at least one of the wellbore, an annulus disposed within the wellbore and a casing disposed within the wellbore.

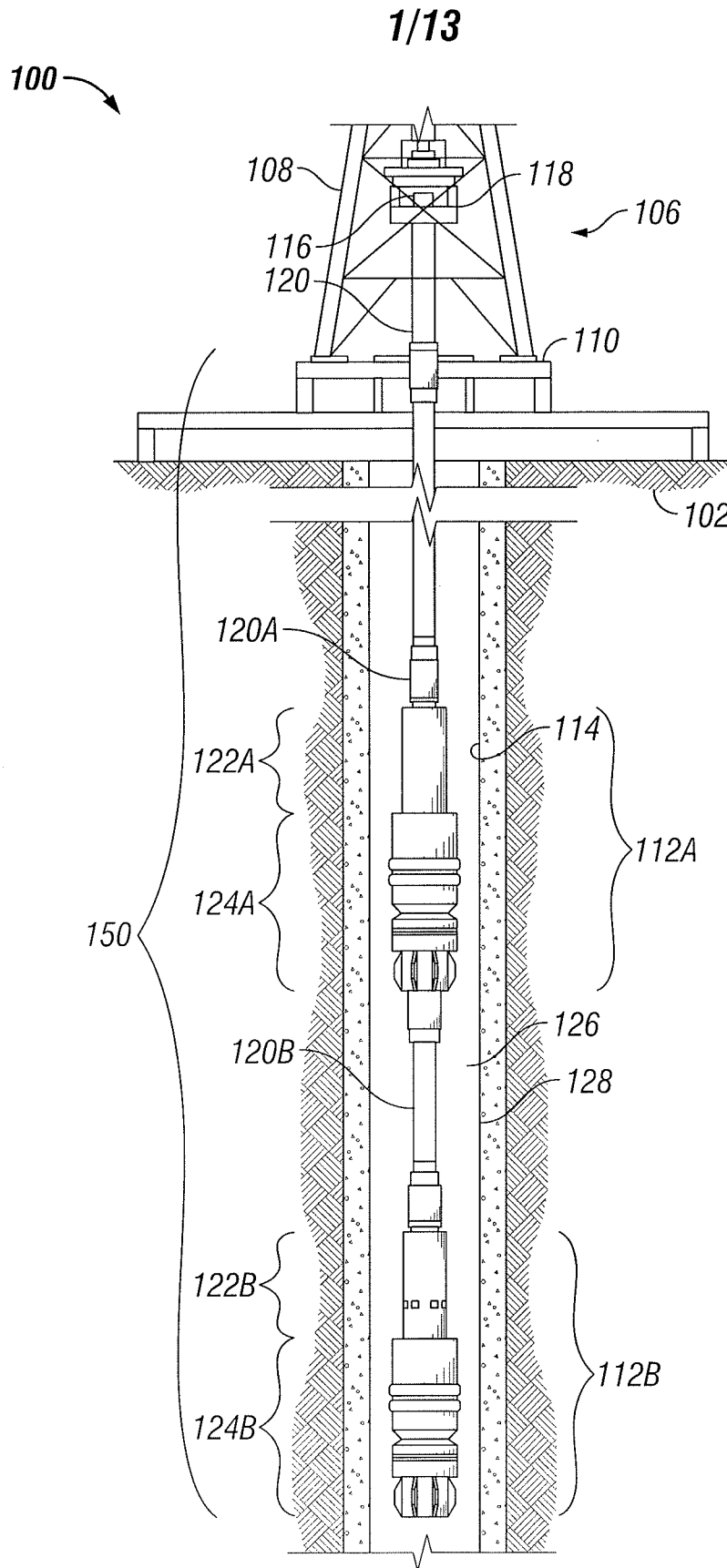
18. The single-run multiple barrier system of claim 11-17, wherein the deep set barrier system further comprises a first centralizer.

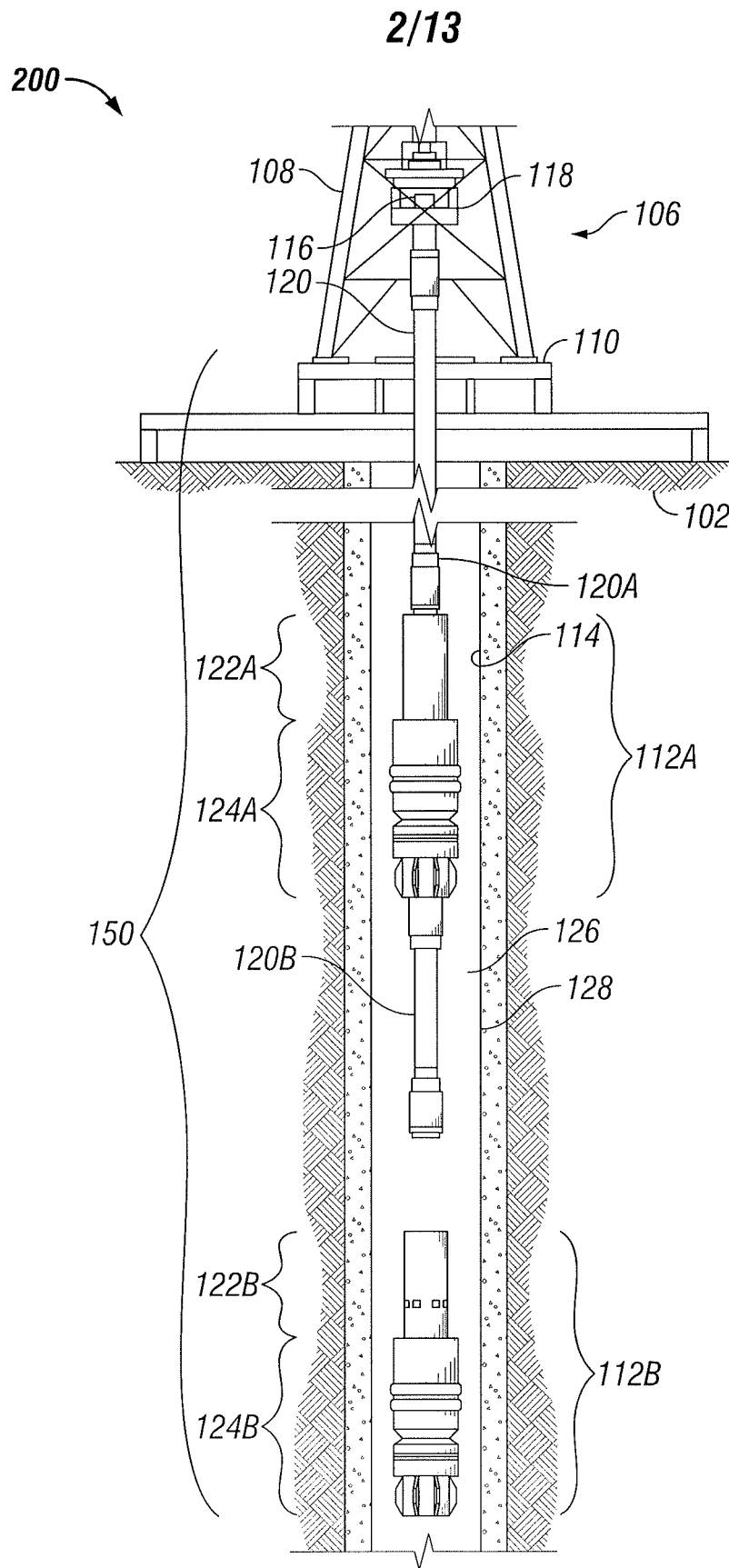
19. The single-run multiple barrier system of claim 11-18, wherein the shallow set barrier system further comprises a second centralizer.

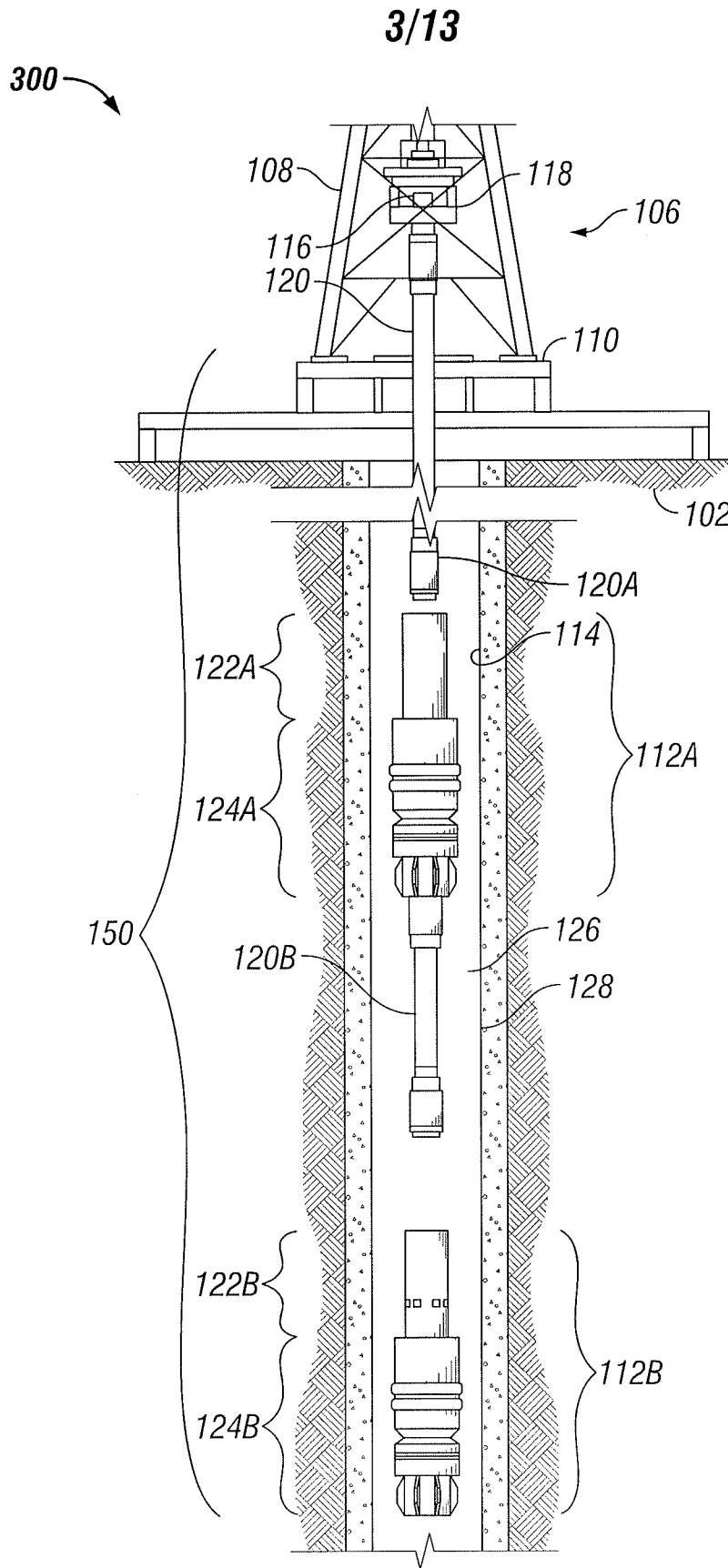
20. The single-run multiple barrier system of claim 11-19, wherein the wellbore tubular string comprises a first wellbore tubular string segment coupled to the first running tool and the

5 shallow set barrier system and a second wellbore tubular string segment coupled to the second running tool, wherein the first running tool disengages from the first wellbore tubular string segment to set the deep set barrier system, and wherein the second running tool disengages from the second wellbore tubular string segment to set the shallow set barrier system.

10 .

**FIG. 1**

**FIG. 2**

**FIG. 3**

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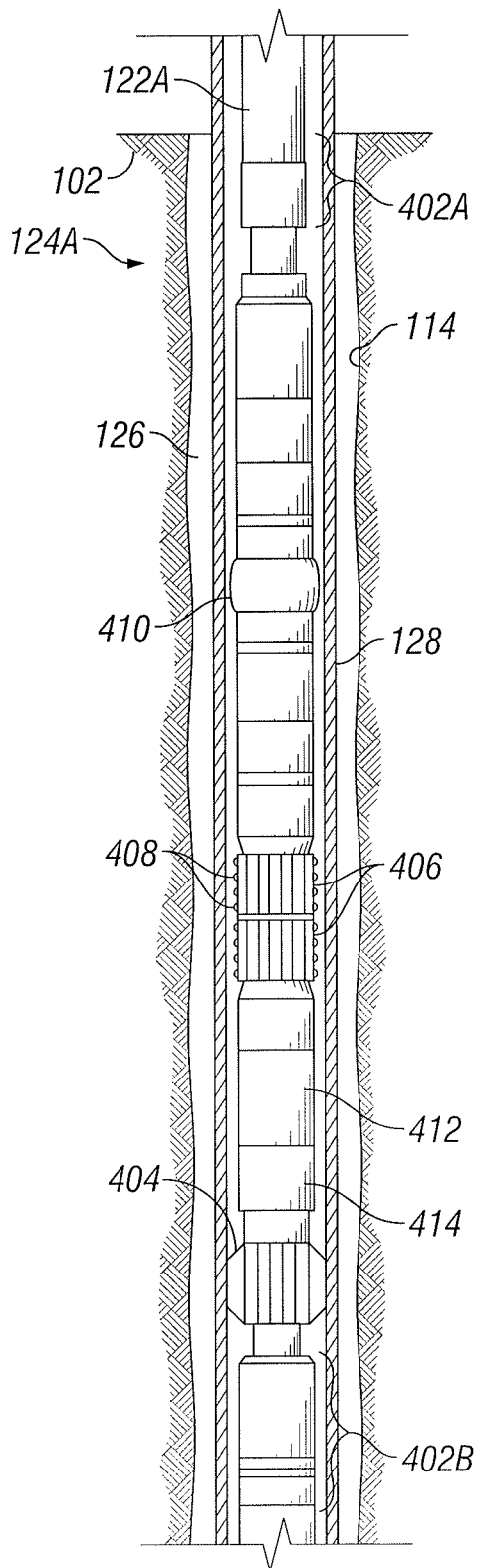


FIG. 4A

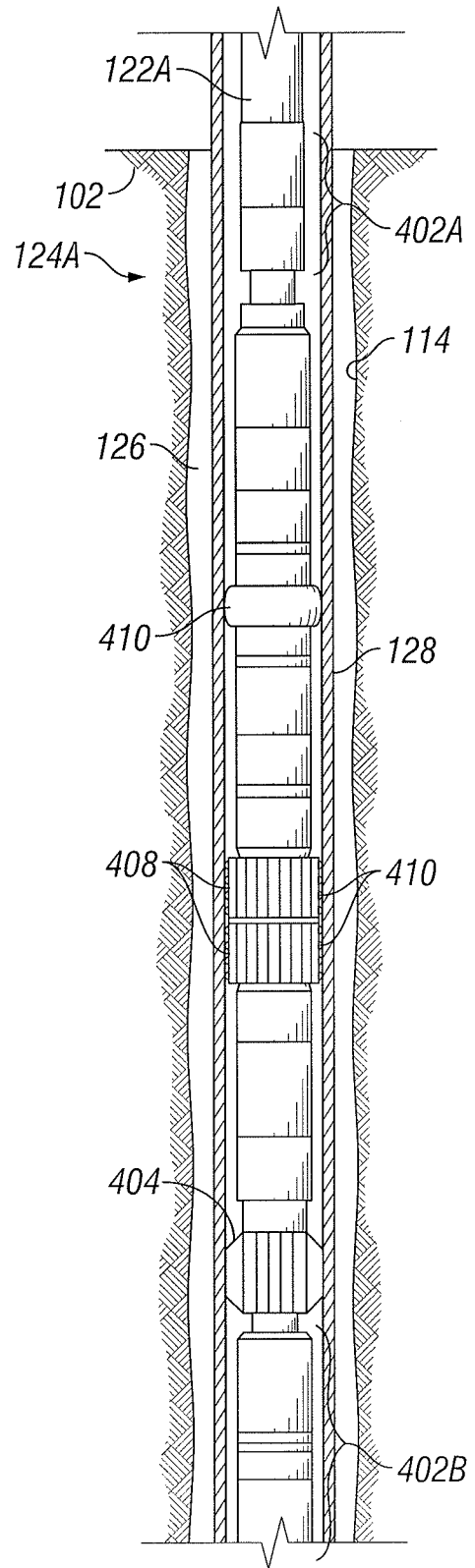


FIG. 4B

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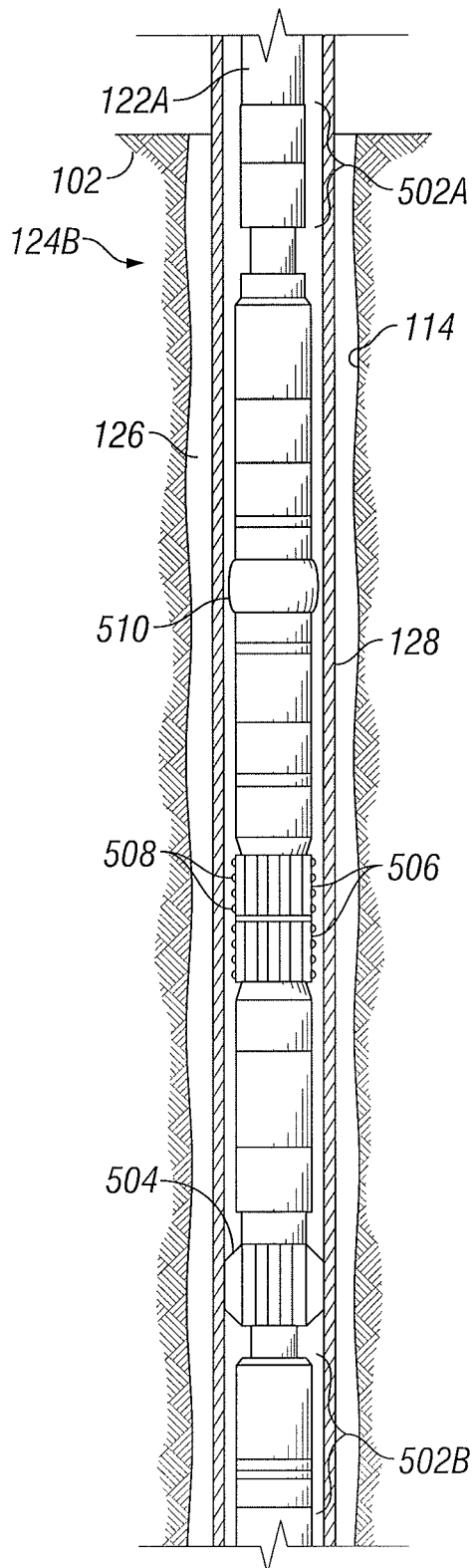


FIG. 5A

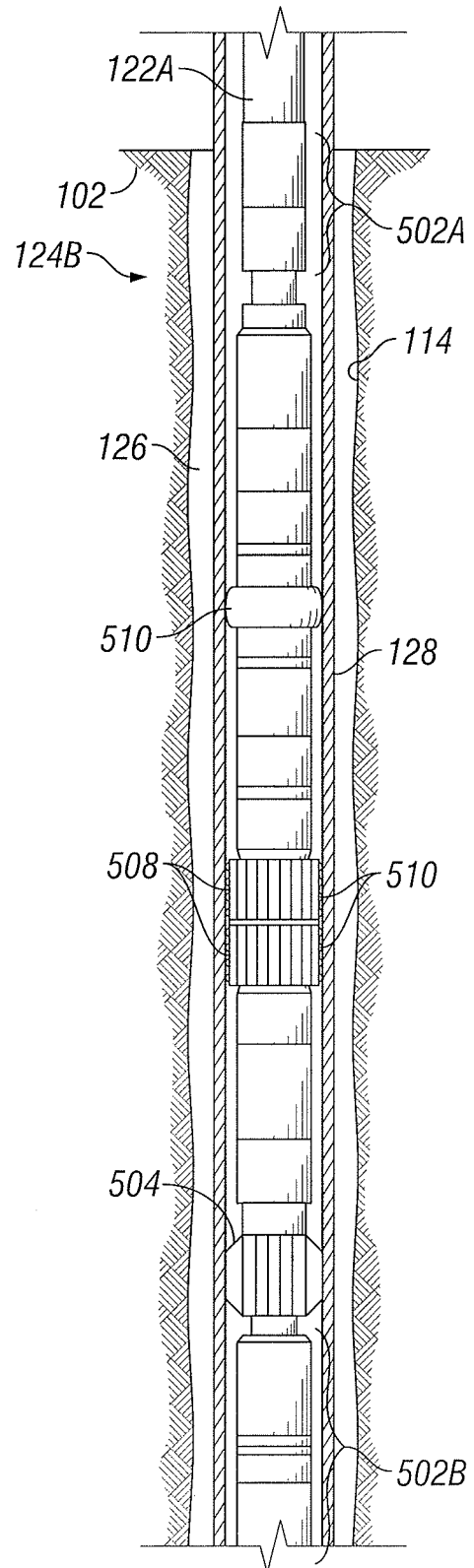


FIG. 5B

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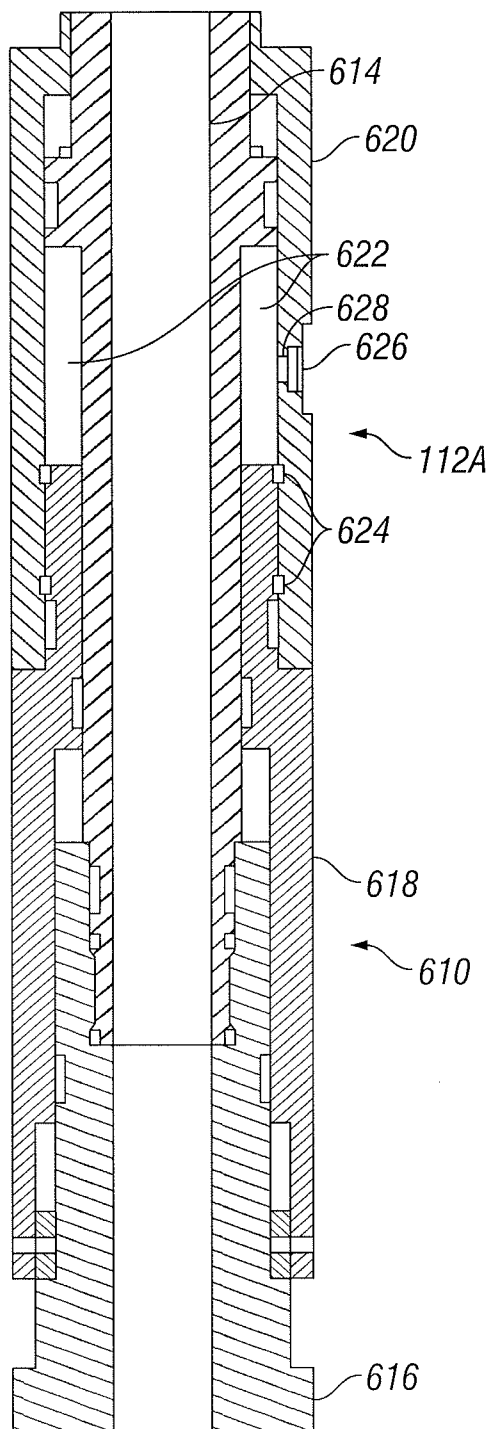


FIG. 6A

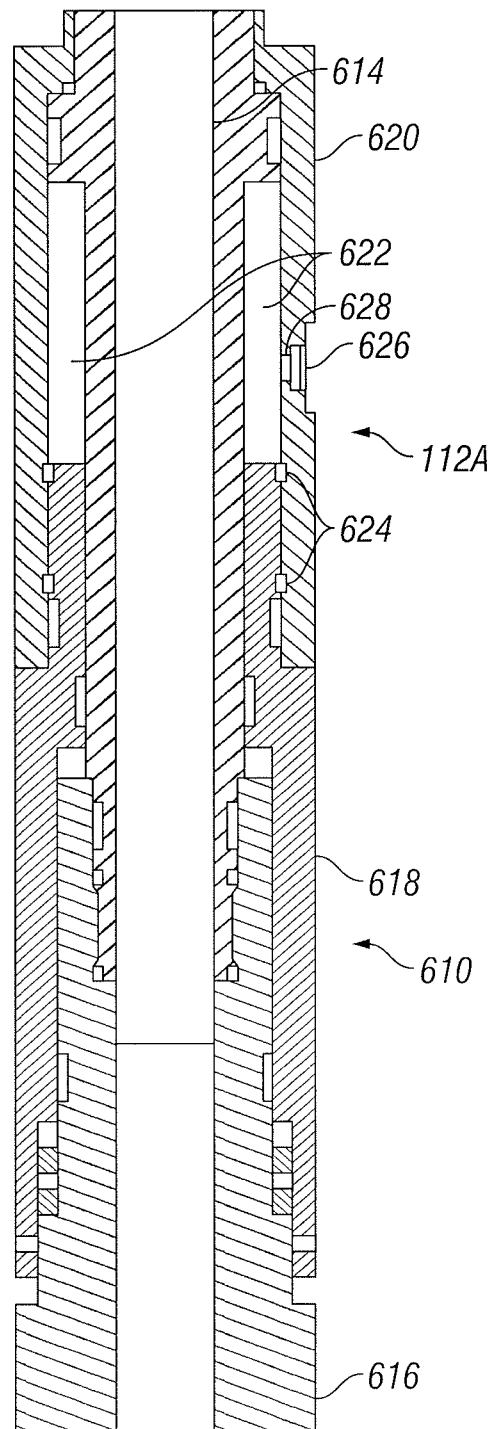


FIG. 6B

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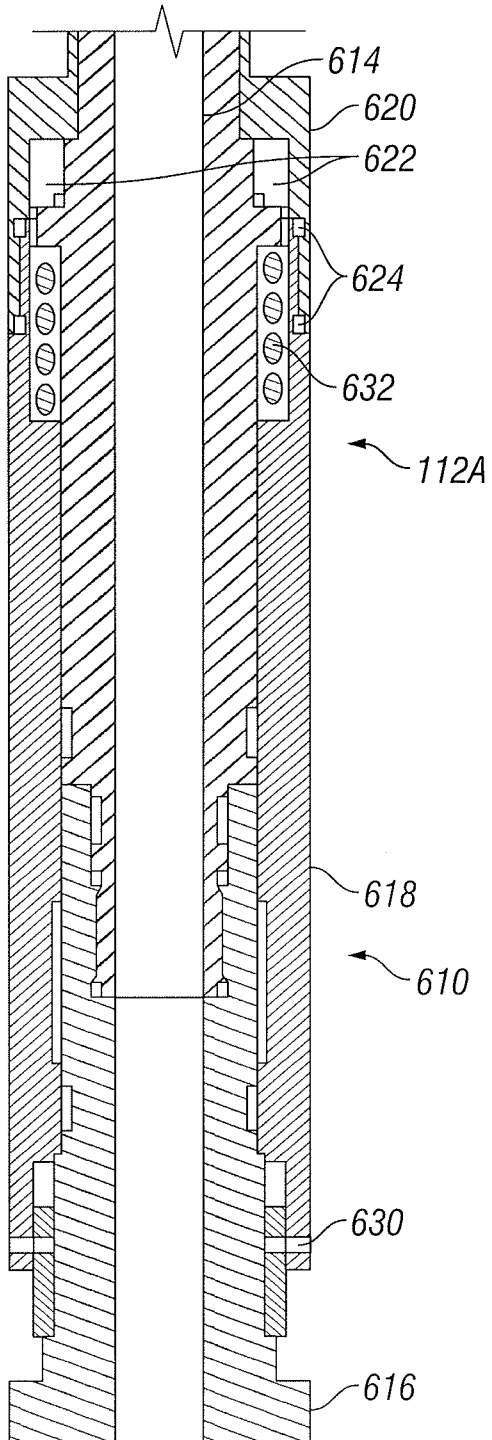


FIG. 7A

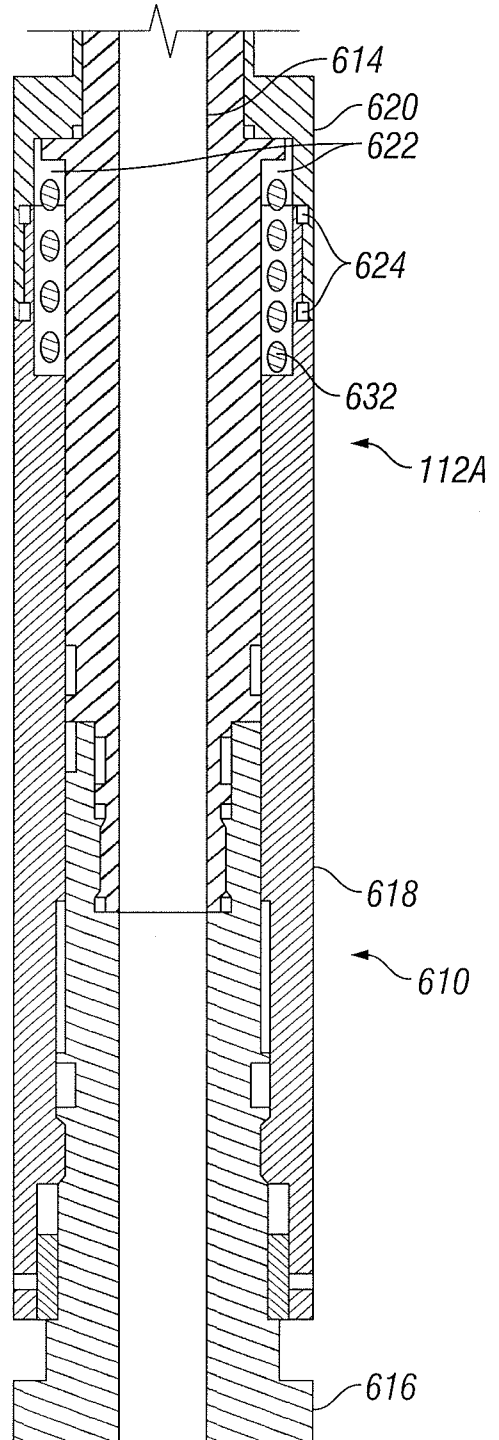


FIG. 7B

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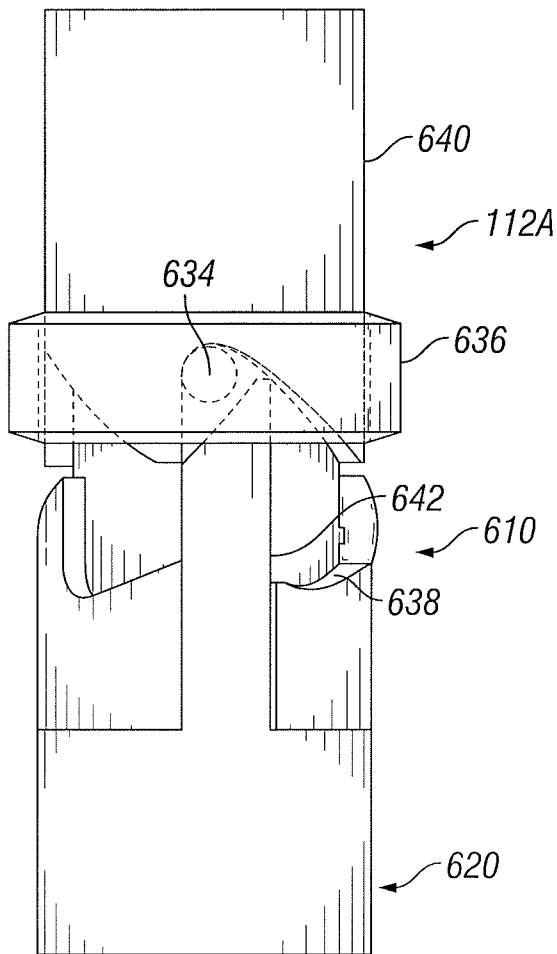


FIG. 8A

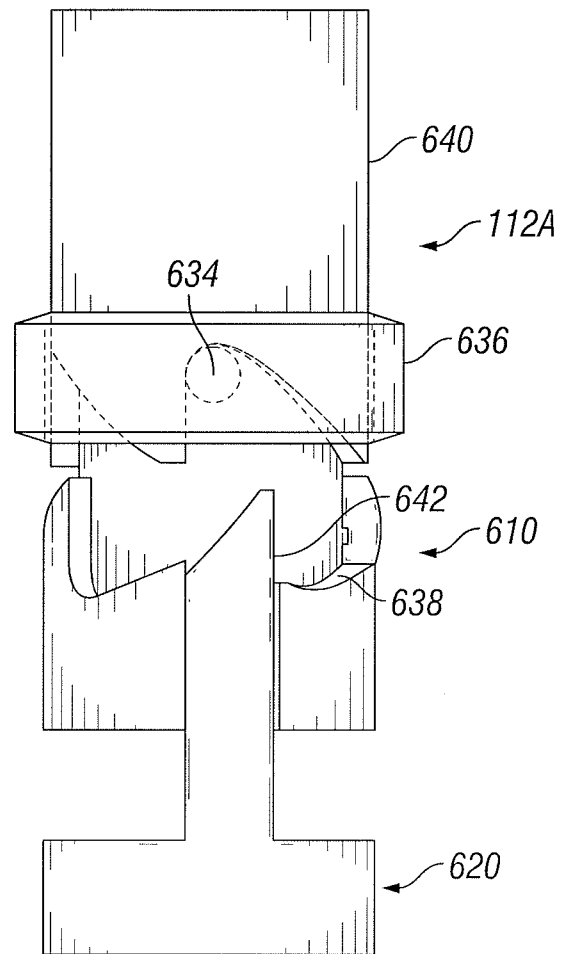


FIG. 8B

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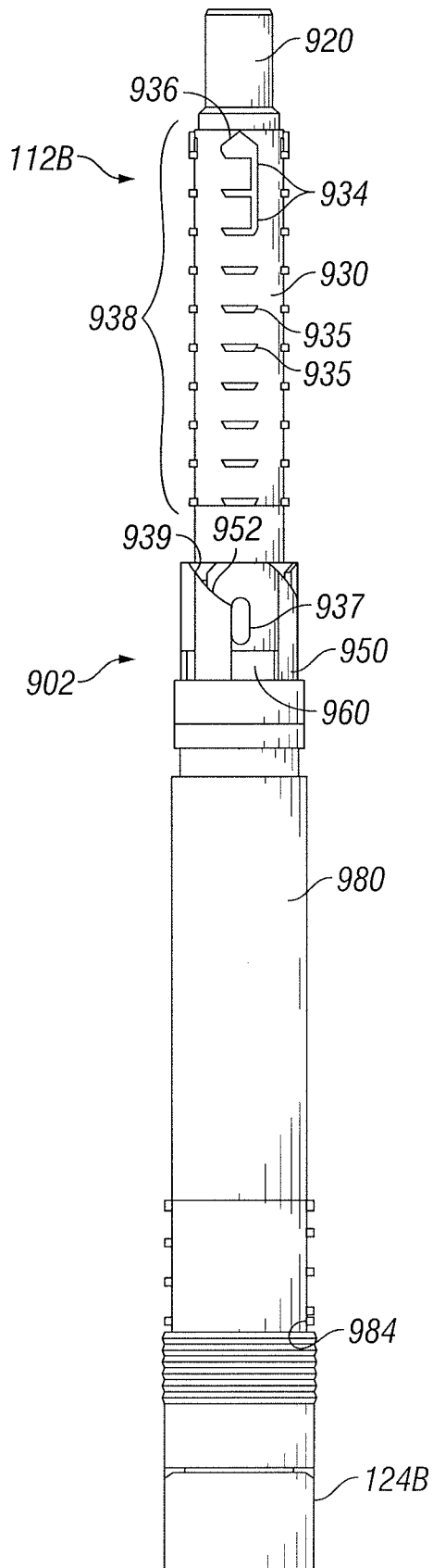


FIG. 9

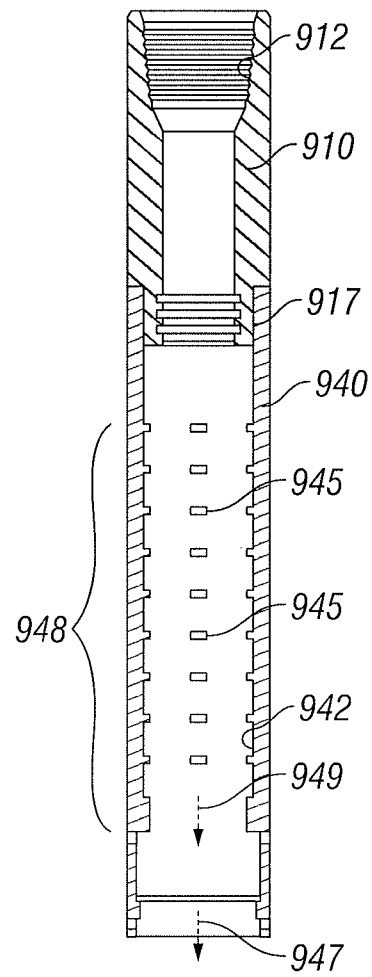


FIG. 10

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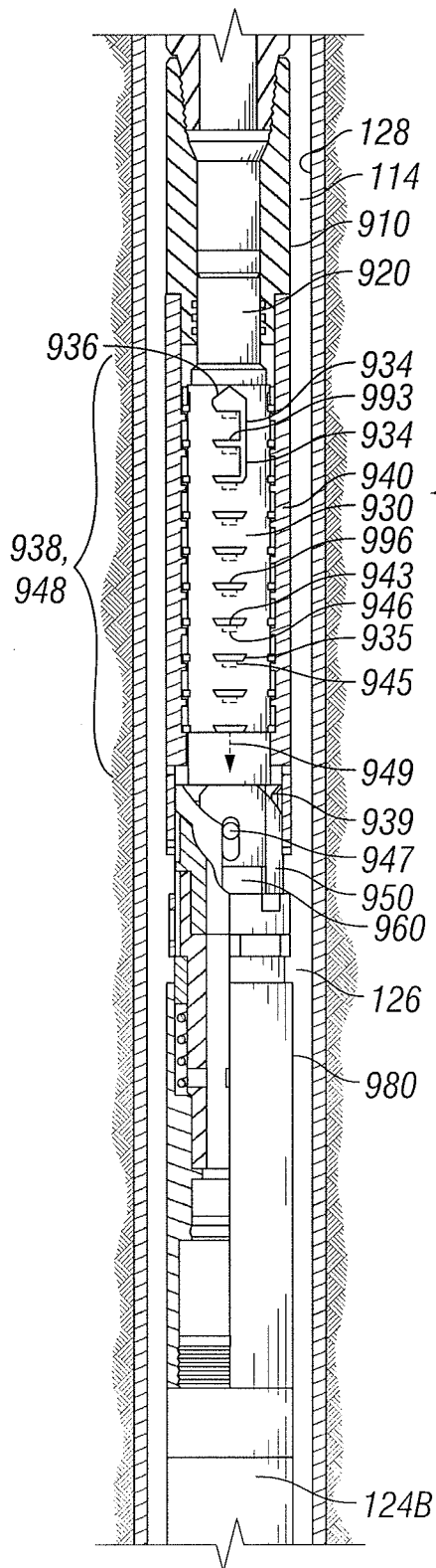


FIG. 11

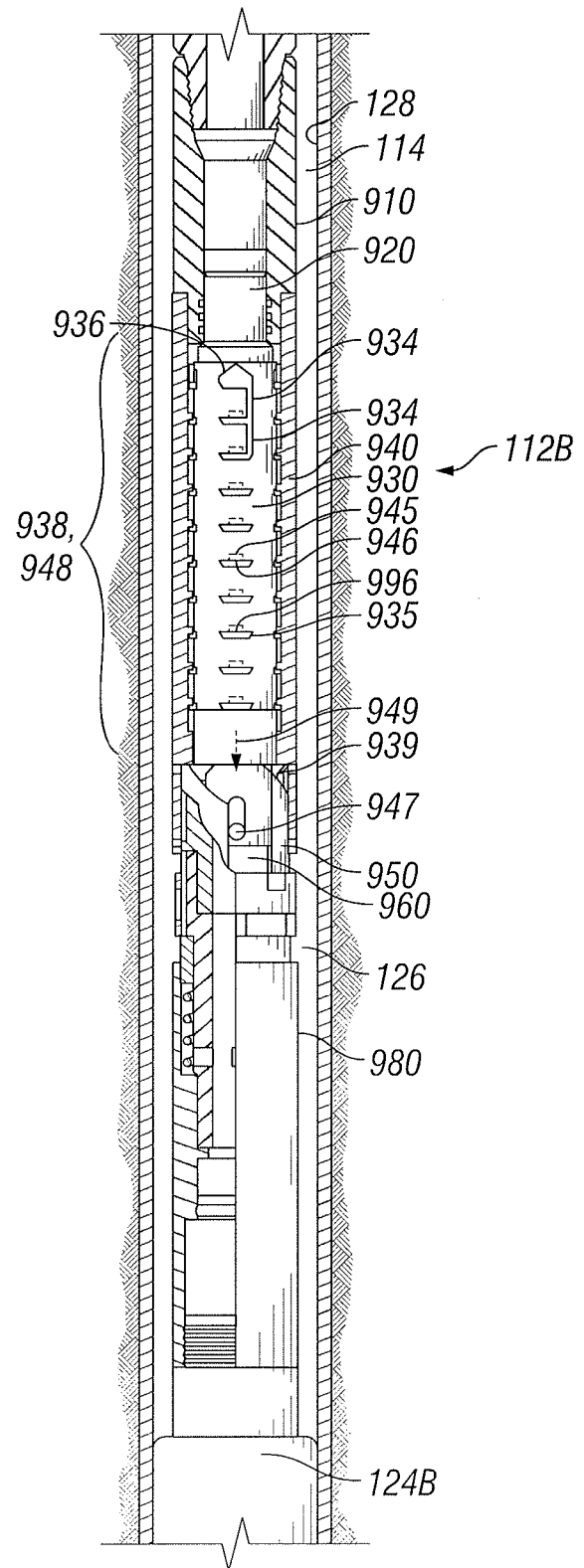


FIG. 12

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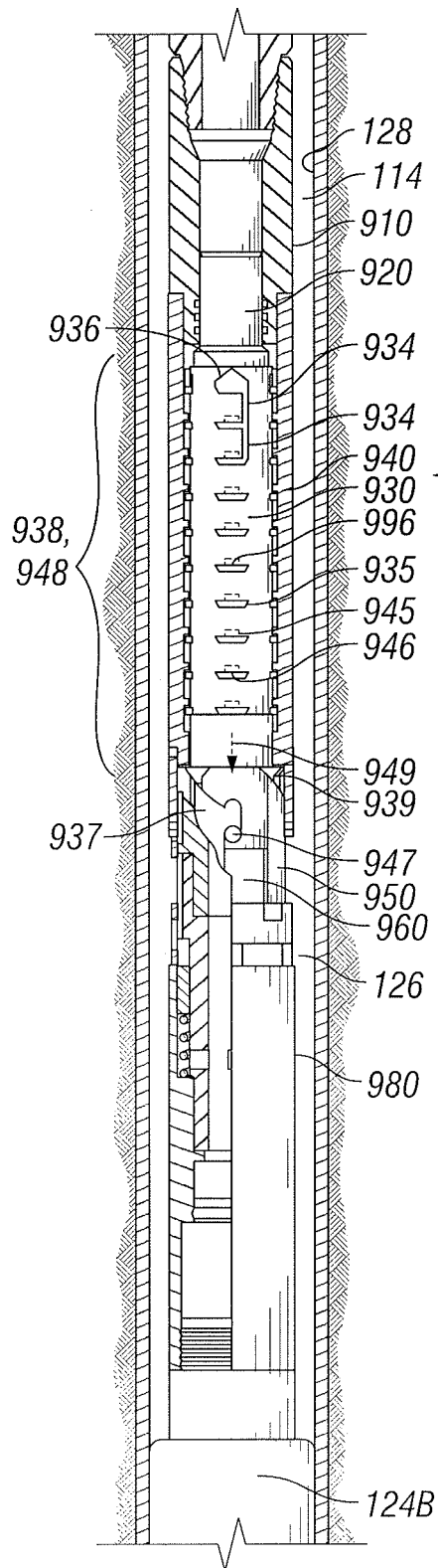


FIG. 13

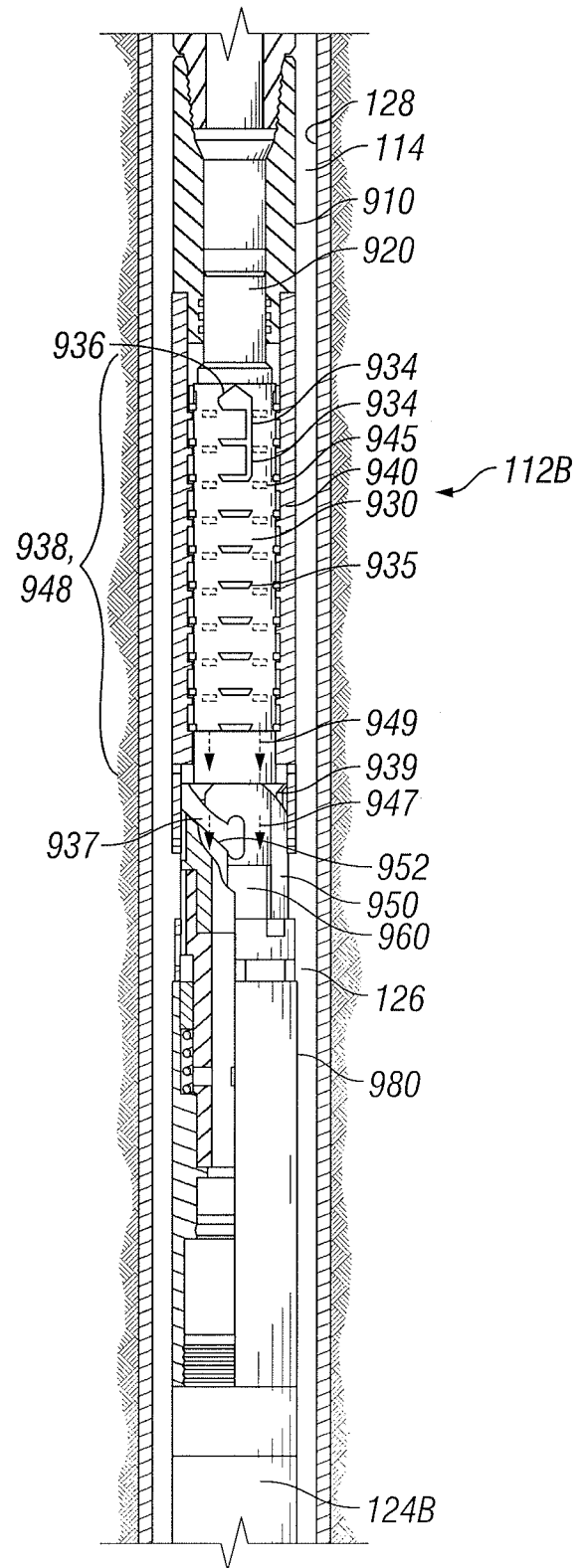


FIG. 14

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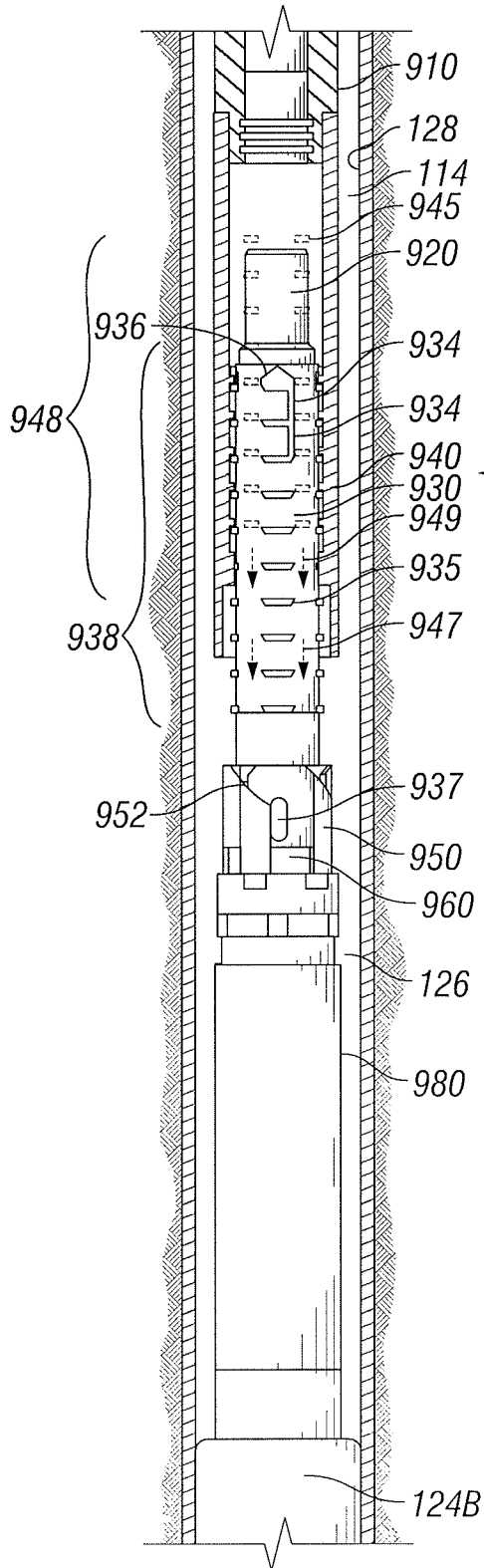


FIG. 15

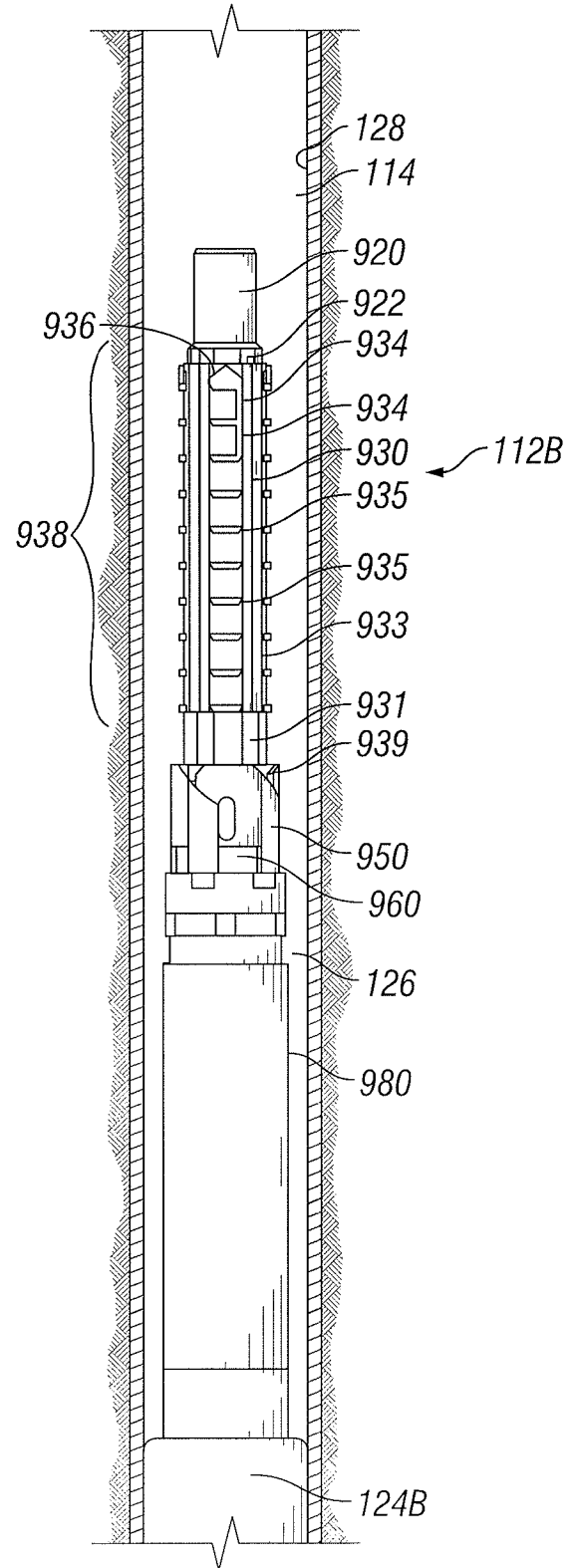
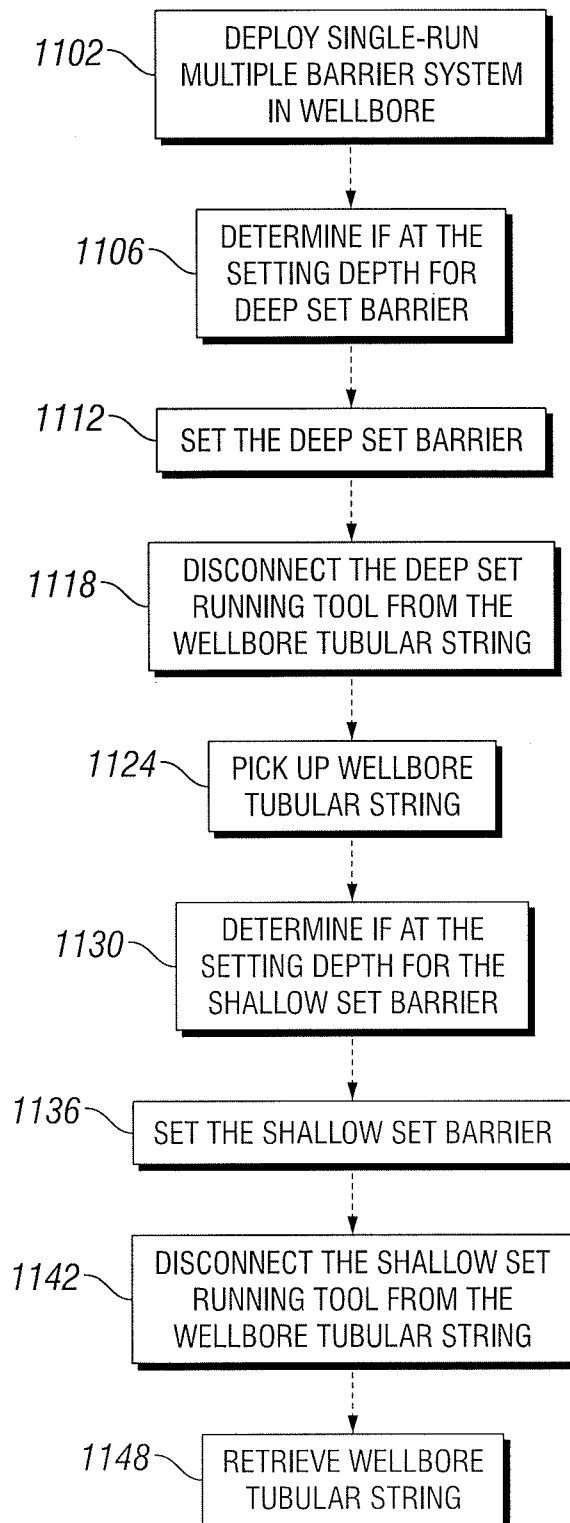


FIG. 16

13/13**FIG. 17**

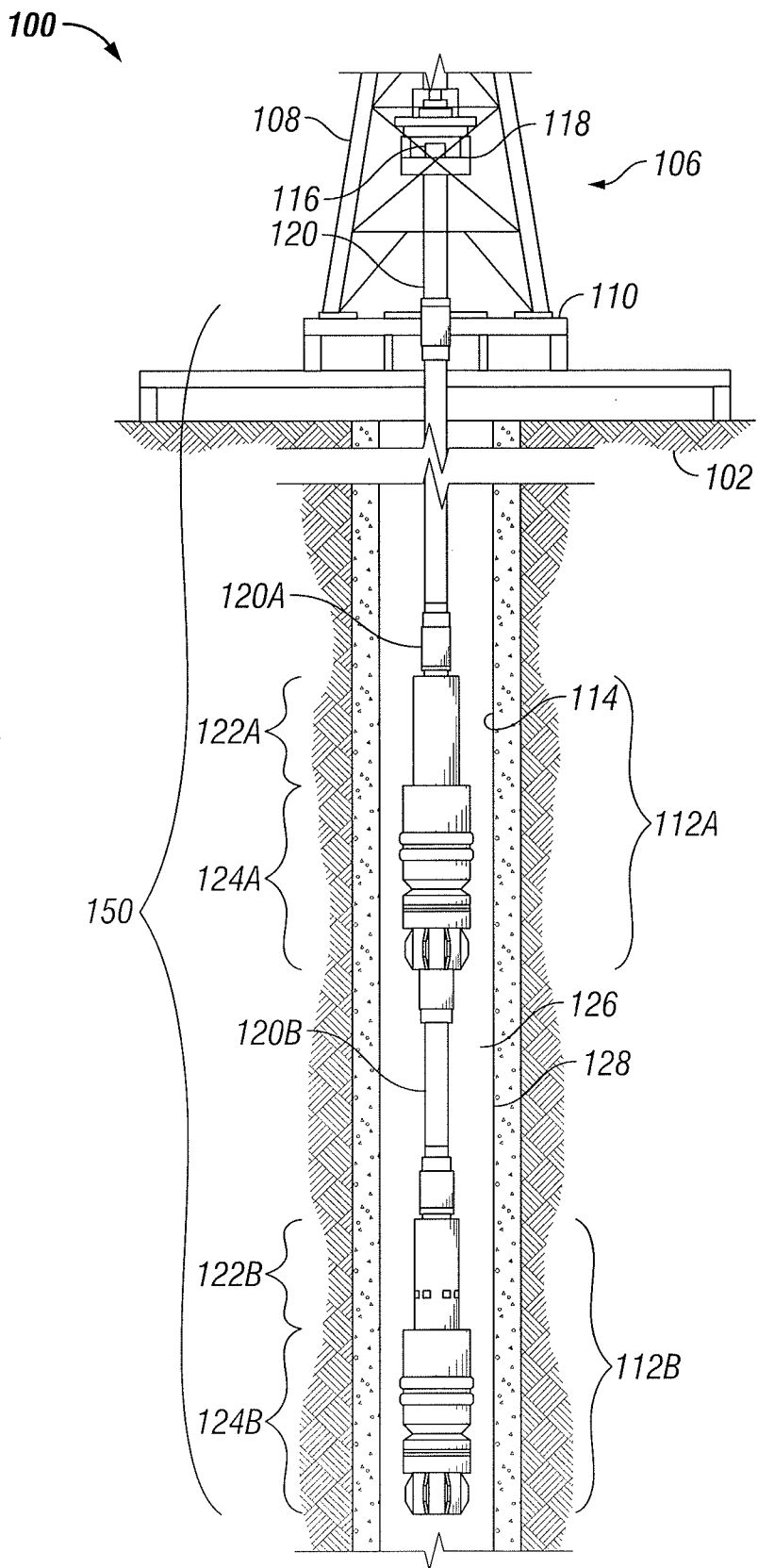


FIG. 1