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(54) **Title**: SYNCHRONIC DUAL PACKER WITH ENERGIZED SLIP JOINT

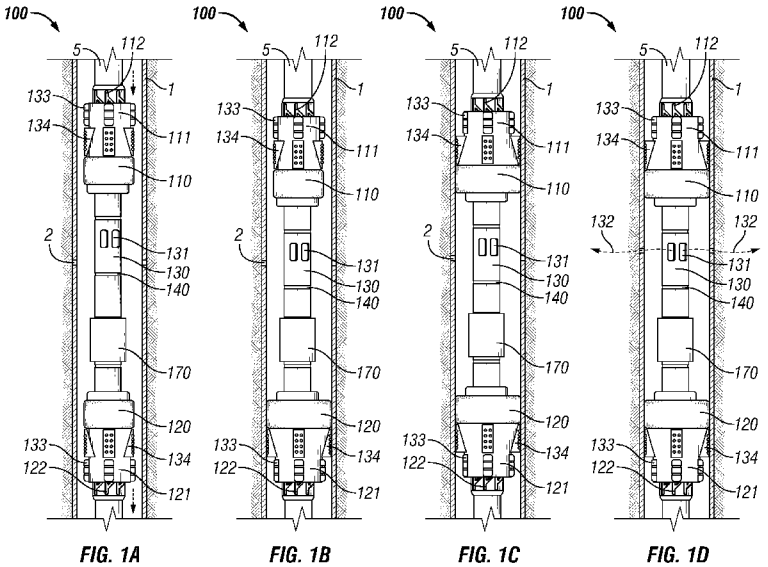

FIG. 1A FIG. 1B FIG. 1C FIG. 1D

(57) **Abstract**: A downhole tool having a first packing element and a second packing element configured to synchronically set to selectively hydraulically isolate a portion of the wellbore. The lower packing element may be first set against the well with the upper packing element next being set against the well. A slip joint permits a change in distance between the packing elements during the setting of the packing elements. The slip joint may be energized to apply a force to the lower packing element to prevent the unsetting of the lower packing element during the setting of the upper packing element. A resilient member may be used to energize the slip joint or the slip joint could be hydraulically or pneumatically energized. Once both packing elements are set, the wellbore may then be treated by flowing fluid out of a ported sub positioned between the packing elements.

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SYNCHRONIC DUAL PACKER WITH ENERGIZED SLIP JOINT

RELATED APPLICATIONS

[0001] The present disclosure is a continuation-in-part application of U.S. Patent Application No. 14/318,952, entitled Synchronic Dual Packer filed on June 30, 2014, the application being incorporated by referenced herein in its entirety.

Field of the Disclosure

[0002] The embodiments described herein relate to downhole tool comprising synchronized packers to hydraulically isolate a portion of a wellbore.

BACKGROUND

Description of the Related Art

[0003] Hydraulically set straddle packers have been previously used to hydraulically isolate a portion of a wellbore. The packing elements of the straddle packer are set upon the application of a predetermined hydraulic pressure to expand the seals into sealing engagement with the casing or tubing of the wellbore. The hydraulic expansion of the sealing elements deteriorates the seals permitting the setting of such a straddle packers for a small finite amount times within a wellbore before the sealing elements need to be replaced.

[0004] A downhole tool may include cup seals that expand out to seal against the casing or tubing in an attempt to seal of the tool with the casing or tubing. However, cups often don't seal equally against the tubing or casing and thus, don't have the sealing integrity desired during completion of an operation with the downhole tool. Mechanical actuating seals generally last longer than the sealing of a hydraulically set straddle packer. A downhole tool may require two sealing elements in order to hydraulically isolate a portion of a wellbore from both above and

below the tool. The use of two mechanically set sealing elements may be problematic on a downhole tool. For example, the movement of the tool to set one of the packing elements may unset the other packing element on the tool. It may be desirable for a downhole that permits the mechanical setting of a first packing element and the later mechanical setting of a second packing element that does not unset the first packing element.

SUMMARY

[0005] The present disclosure is directed to a downhole tool having synchronized packers and method that overcomes some of the problems and disadvantages discussed above.

[0006] One embodiment is a dual packer comprising a first packing element and a second packing element. The dual packer includes a first sleeve having a first j-slot track, wherein movement of a first pin along the first j-slot track actuates the first packing element between a set position and a running position. The dual packer includes a second sleeve having a second j-slot track, wherein movement of a second pin along the second j-slot track actuates the second packing element between a set position and a running position. The first packing element may be an upper packer that is set in tension and the second packing element may be a lower packer that is set in compression. The first packing element may be an upper packer that is set in compression and the second packing element may be a lower packer that is set in tension. The dual packer may be used for treating a wellbore formation. The treating of the wellbore formation may further comprise stimulating the wellbore formation. The treating of the wellbore formation may further comprise fracturing the wellbore formation.

[0007] The second j-slot track of the dual packer may be inverted with respect to the first j-slot track. The first j-slot track may have six pin positions along a circumferential length of the first j-slot track and the second j-slot track may have four pin positions along a circumferential

length of the second j-slot track. The six pin positions of the first j-slot track may be approximately sixty degrees apart and the four pin positions of the second j-slot track may be approximately ninety degrees apart. The movement of the second pin from a second pin position to a third pin position along the second j-slot track may set the second packing element and movement of the first pin from a third pin position to a fourth pin position along the first j-slot track may set the first packing element. A second distance between the third pin position and a fourth pin position of the second j-slot track may be greater than a first distance between the third pin position and the fourth pin position of the first j-slot track. The first distance may be approximately two thirds the second distance. The first j-slot track may include more than one set of six pin positions along a circumferential length of the first j-slot track and the second j-slot track may include more than one set of four pin positions along a circumferential length of the second j-slot track.

[0008] One embodiment is a system to isolate a treat a portion of a wellbore. The system comprising an upper packer, a lower packer, and a portion sub being connected between the upper packer and the lower packer. The system includes a first sleeve having a j-slot track, wherein movement of a first pin along the j-slot track of the first sleeve actuates the upper packer between a set position and a running position. The system includes a second sleeve having a j-slot track, wherein movement of a second pin along the j-slot track of the second sleeve actuates the lower packer between a set position and a running position. The system may include a work string connected to the upper packer, wherein fluid may be pumped down the work string and out the ported sub. The j-slot track of the second sleeve of the system may be inverted with respect to the j-slot track of the first sleeve. The j-slot track of the first sleeve may have six pin

positions along the first sleeve and the j-slot track of the second sleeve may have four pin positions along the second sleeve.

[0009] One embodiment is a method of isolating a portion of a wellbore. The method comprises running a tool on a work string into a wellbore and positioning the tool adjacent a portion of the wellbore. The method comprises picking up the work string, setting a lower packer of the tool, and setting an upper packer of the tool after setting the lower packer. The method comprises releasing the upper packer of the tool and releasing the lower packer of the tool after releasing the upper packer.

[0010] Picking up the work string may move a first pin from a first pin position on a j-slot track of a first sleeve to a second pin position and may move a second pin from a second pin position on a j-slot track of a second sleeve to a second pin position. Setting the lower packer may comprises moving the first pin from the second pin position on the j-slot track of the first sleeve to a third position and moving the second pin from the second pin position on the j-slot track of the second sleeve to a third position. Setting the upper packer may comprises moving the first pin from the third pin position on the j-slot track of the first sleeve to a fourth pin position while the lower packer remains set. Releasing the upper packer may comprise moving the first pin from the fourth pin position on the j-slot track of the first sleeve to a fifth pin position while the lower packer remains set. Releasing the lower packer may comprise moving the first pin from the fifth pin position on the j-slot track of the first sleeve to a sixth pin position and moving the second pin from the third pin position on the j-slot track of the second sleeve to a fourth pin position. The method may include pumping fluid down the work string and out a ported sub of the tool after setting the upper packer of the tool. The upper packer may be set in tension and the lower packer may be set in compression.

[0011] One embodiment is a dual packer comprising a first packing element movable between a set position and a running position, a second packing element movable between a set position and a running position, and a slip joint positioned between the first packing element and the second packing element. The slip joint is configured to change a length between the first and second packing elements.

[0012] The slip joint may be energized. The slip joint may be comprised of an upper portion and a lower portion, the upper and lower portions being movable relative to one another to change the length between the first and second packing elements. A resilient member positioned between a shoulder of the upper portion and a shoulder of the lower portion may energize the slip joint. The energized slip joint may apply a force on the second packing element when the second packing element is in the set position. The slip joint may be energized by a resilient member. The slip joint may comprise a chamber, wherein the chamber may energize the slip joint. The chamber may be hydraulically or pneumatically energized. The slip joint may be energized by a resilient member positioned within the chamber. The dual packer may include a first sleeve having a first j-slot track, wherein movement of a first pin along the first j-slot track actuates the first packing element between the set position and the running position. The dual packer may include a second sleeve having a second j-slot track, wherein movement of a second pin along the second j-slot track actuates the second packing element between the set position and the running position.

[0013] One embodiment is a system to isolate and treat a portion of a wellbore comprising an upper packer and a first sleeve having a j-slot track, wherein movement of a first pin along the j-slot track of the first sleeve actuates the upper packer between a set position and a running position. The system comprises a lower packer and a second sleeve having a j-slot track,

wherein movement of a second pin along the j-slot track of the second sleeve actuates the lower packer between a set position and a running position. The system comprises a ported sub being connected between the upper packer and the lower packer and a slip joint being connected between the upper packer and the lower packer, the slip joint is configured to change a length between the upper and lower packers.

[0014] The slip joint may be energized to provide a force on the lower packer when the lower packer is in the set position. The slip joint may be energized hydraulically, pneumatically, or by a resilient member. The system may comprise a work string connected to the upper packer, wherein fluid may be pumped down the work string and out the ported sub.

[0015] One embodiment is a method of isolating a portion of a wellbore comprising running a tool on a work string into a wellbore and positioning the tool adjacent a portion of the wellbore. The method comprises picking up the work string and setting a lower packer of the tool. The method comprises applying a force to the set lower packer and setting an upper packer of the tool after setting the lower packer.

[0016] The method may comprise treating a formation of the wellbore through a port in a tubular. Treating the formation of the wellbore may comprise at least one of fracture, re-fracturing, stimulating, tracer injection, cleaning, acidizing, steam injection, water flooding, and cementing. The method may comprise releasing the upper packer of the tool and relating the lower packer of the tool after releasing the upper packer. An energized slip joint may apply the force to the set lower packer. A resilient member may energize the slip joint. The resilient member may be positioned between two shoulders of the slip joint. The slip joint may be energized hydraulically. The slip joint may be energized pneumatically.

BRIEF DESCRIPTION OF THE DRAWINGS

[0017] FIG. 1A shows an embodiment of a downhole tool having two packing elements within a wellbore.

[0018] FIG. 1B shows an embodiment of a downhole tool with the lower packing element set within a wellbore.

[0019] FIG. 1C shows an embodiment of a downhole tool with the upper and lower packing elements set within a wellbore.

[0020] FIG. 1D shows the treatment of a portion of a wellbore that has been hydraulically isolated by an embodiment of a downhole tool.

[0021] FIG. 2 shows a depiction of an upper sleeve having a continuous j-slot track and a depiction of a lower sleeve having a continuous j-slot track.

[0022] FIG. 3 shows a depiction of an upper sleeve having a continuous j-slot track and a depiction of a lower sleeve having a continuous j-slot track.

[0023] FIG. 4 shows a depiction of an upper sleeve having a continuous j-slot track and a depiction of a lower sleeve having a continuous j-slot track.

[0024] FIG. 5 shows a depiction of an upper sleeve having a continuous j-slot track and a depiction of a lower sleeve having a continuous j-slot track.

[0025] FIG. 6 shows a depiction of an upper sleeve having a continuous j-slot track and a depiction of a lower sleeve having a continuous j-slot track.

[0026] FIG. 7 shows a depiction of an upper sleeve having a continuous j-slot track and a depiction of a lower sleeve having a continuous j-slot track.

[0027] FIG. 8 shows a depiction of an upper sleeve having a continuous j-slot track and a depiction of a lower sleeve having a continuous j-slot track.

[0028] FIG 9 shows an embodiment of a method of isolating a portion of a wellbore.

[0029] FIG. 10 shows an embodiment of a downhole tool having two packing elements within a wellbore.

[0030] FIG. 11A shows an embodiment of a downhole tool having two packing elements within a wellbore.

[0031] FIG. 11B shows an embodiment of a downhole tool with the lower packing element set within a wellbore.

[0032] FIG. 11C shows an embodiment of a downhole tool with the upper and lower packing elements set within a wellbore.

[0033] FIG. 11D shows the treatment of a portion of a wellbore that has been hydraulically isolated by an embodiment of a downhole tool.

[0034] FIG. 12 shows one embodiment of an energized slip joint that may be used in a downhole tool having two packing elements.

[0035] FIG. 13 shows a cross-section view of shows one embodiment of an energized slip joint that may be used in a downhole tool having two packing elements.

[0036] FIG. 14 shows a cross-section view embodiment of an energized slip joint that may be used in a downhole tool having two packing elements.

[0037] FIG. 15 shows an embodiment of a method of isolating a portion of a wellbore.

[0038] While the disclosure is susceptible to various modifications and alternative forms, specific embodiments have been shown by way of example in the drawings and will be described in detail herein. However, it should be understood that the disclosure is not intended to be limited to the particular forms disclosed. Rather, the intention is to cover all modifications, equivalents and alternatives falling within the scope of the invention as defined by the appended claims.

DETAILED DESCRIPTION

[0039] FIG. 1A shows an embodiment of a downhole tool 100 having a first packing element 110 and a second packing element 120. The first packing element 110 may be an upper packer and the second packing element 120 may be a lower packer. The first and second packing elements 110 and 120 may each comprise a plurality of packing elements configured to create a seal between the tool 100 and casing 1, or tubing, of a wellbore. The downhole tool 100 is conveyed into the wellbore via a work string 5 and positioned at a desired location within the wellbore. For example, the downhole tool 100 may be positioned adjacent a perforation(s) 2 in the casing 1. The wellbore may then be treated via the tool 100 as discussed herein. The work string 5 may be various strings as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure. FIG. 1A shows the packing elements 110 and 120 in a running position, *i.e.* a retracted or unset orientation, so that the tool 100 may be moved through the casing or tubing 1 of the wellbore. The tool 100 includes a ported sub 130 having one or more flow ports 131 and a quick disconnect sub 140 that are described herein.

[0040] FIG. 1B shows the second, or lower, packing element 120 set against the casing 1 of the wellbore to create a seal between the tool 100 and the casing 1. The second packing element 120 may be set in compression by the rotation of a sleeve or rotating sub 121 connected to the second packing element 120 as described herein. The rotation of the sleeve or rotating sub 121 moves an element along a j-slot track 122 that actuates the second packing element between a set and unset state as described herein. FIG. 1C shows the first, or upper, packing element 110 set against the casing 1 of the wellbore to create a seal between the tool 100 and the casing 1. The first packing element 110 may be set in tension by the rotation of a sleeve or rotating sub 111 connected to the first packing element 110 as described herein. The rotation of the sleeve or

rotating sub 111 moves an element along a j-slot track 112 that actuates the first packing element between a set and unset state as described herein. The downhole tool 100 may include a slip joint 170 positioned between the upper and lower packing elements 110 and 120. The slip joint 170 permits the lengthening of the distance between the lower packing element 120 and the upper packing element 110 while the upper packing element 110 is being set within the wellbore. As detailed herein, the lower packing element 120 may be set within the wellbore before the upper packing element 110 is set. The lengthening of the distance between the packing elements 110 and 120 may aid in preventing the lower packing element 120 from becoming unset during the setting of the upper packing element 110.

[0041] The setting of the first and second packing elements 110 and 120 hydraulically isolates the portion of the wellbore between the packing elements 110 and 120 from the rest of the wellbore. The downhole tool 100 may include drag blocks 133 and slips 134 to help retain the packing elements 110 and 120 in a set state within the casing 1. FIG. 1D shows the treatment of the wellbore by flowing fluid out of the flow ports 131 of the ported sub 130 as shown by arrows 132. The formation of the wellbore may be treated via perforations 2 through the casing 1. Fluid is pumped down the work string 5 and out the ports 131 of the ported sub 130. After the portion of the wellbore has been treated, the packing elements 110 and 120 may be unset, i.e. moved to their running position, and the tool 100 may be moved to another location within the wellbore. Treating the wellbore formation may comprise various applications such as stimulating or fracturing the formation as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure. The quick disconnect sub 140 permits the upper portion of the tool 100 to be disconnected from the second packing element 120 to the extent the tool 100 becomes stuck within the wellbore. The upper portion of the tool 100 and the work string 5 may

then be removed from the wellbore. The lower portion of the tool 100 may then be fished out of the wellbore. Alternatively, the lower portion of the tool 100 may be drilled out or simply pushed to the bottom of the wellbore.

[0042] FIG. 2 schematically depicts an embodiment of a first, or upper, sleeve 111 having a first continuous j-slot track 112 and schematically depicts an embodiment of a second, or lower, sleeve 121 having a second continuous j-slot track 122. The sleeves 111 and 121 are circular and have the continuous j-slot tracks 112 and 122 extending completely around the perimeter of the sleeves 111 and 121. The sleeves 111 and 121 have been shown schematically, *i.e.* have been shown flattened out with more 360 degrees shown, for illustrative purposes only. FIG. 2 shows a first, or upper, pin 113 at a first pin position 114 on the first j-slot track 112 and a second, or lower, pin 123 at a first pin position 124 on the second j-slot track 122. The first and second packing elements 110 and 120 are in the running, or unset, positions (shown in FIG. 1A) when the pins 113 and 123 are in their respective first pin positions 114 and 124. The downhole tool 100 is run into the wellbore with the pins 113 and 123 in their respective first pin positions 114 and 124.

[0043] As shown in FIG. 2, the first pin positions 114 and 124 of the first and second j-slot tracks 112 and 122 are in axial alignment with each other as indicated by line 150. Thus, the two packing elements 110 and 120 are synchronized being placed into the running positions together as detailed herein. The second j-slot track 122 is inverted with respect to the first j-slot track 112, in that the direction of travel of the second pin 123 along the second j-slot track 122 to the set position, the third pin position 126, for the second packing element 120 is in the opposite direction of travel that the first pin 113 travels along the first j-slot track 112 to the set position, the fourth pin position 117, for the first packing element 110 as described herein. In the

embodiment shown, the second pin 123 travels in a downward direction to reach the set position and the first pin 113 travels in an upward direction to reach the set position.

[0044] The first j-slot track 112 has a first pin position 114, a second pin position 115, a third pin position 116, a fourth pin position 117, a fifth pin position 118, and a sixth pin position 119. The movement of the pin 113 between the pin positions 114-119 actuates the first, or upper, packing element 110 between a running position and set position as detailed herein. From the sixth pin position 119 the pin 113 next moves into the first pin position 114 as pin 113 has traversed the first j-slot track 112 for 360 degrees around the first sleeve 111. Alternatively, the first sleeve 111 may be designed to have multiple first, second, third, fourth, fifth, and sixth pin positions 114-119 located around its perimeter as long as there is an equal number of each pin position as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure.

[0045] The second j-slot track 122 has a first pin position 124, a second pin position 125, a third pin position 126, and a fourth pin position 127. The movement of the pin 123 between the pin positions 124-127 actuates the second, or lower, packing element 120 between a running position and set position as detailed herein. From the fourth pin position 127 the pin 123 next moves into the first pin position 124 as pin 123 has traversed the second j-slot track 122 for 360 degrees around the second sleeve 121. Alternatively, the second sleeve 121 may be designed to have multiple first, second, third, and fourth pin positions 124-127 located around its perimeter as long as there is an equal number of each pin position as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure.

[0046] As discussed above, the tool 100 is inserted into the wellbore with the pins 113 and 123 in their respective first pin positions 114 and 124. Once the tool 100 is positioned at a

desired location within the wellbore, the tool 100 is stopped and the work string 5 is picked up in the hole moving the pins 113 and 123 to their respective second pin positions 115 and 125 as shown in FIG. 3. The second or lower packer 120 is then set within the wellbore to create a lower seal between the tool 100 and the casing 1 by moving the pins 113 and 123 to their respective third pin positions 116 and 126 as shown in FIG. 4. The movement of the pins 113 and 123 to their respective third pin positions 116 and 126 is down by pushing down the work string 5, which sets the lower packing element 120 in compression.

[0047] After the lower packing element 120 is set, the upper packing element 110 is set within the casing 1 of the wellbore by pulling up on the work string 5, which moves the first pin 113 to the fourth pin position 117 as shown in FIG. 5. The upper packing element 110 is set in tension due to the upward movement of the work string 5 while the lower portion of the tool 100 remains static due to the lower packing element 120 remaining set in the wellbore as discussed herein.

[0048] The upward movement of the work string 5 moves the second pin 123 to a location 128 along the second j-slot track 122, but does not unset the lower packing element 120 because the second pin 123 does not move, at this time, into the fourth pin position 127 on the second j-slot track 122. The third and fourth positions 126 and 127 on the second j-slot track 122 are designed to be separated by a second distance 160 that is longer than a first distance 155 that separates the third and fourth positions 116 and 117 of the first j-slot track 112. Thus, the second pin 123 does not move into the fourth pin position 127 along the second j-slot track 122 and the lower packing element 120 remains set while the upper packing element 110 is being set. At this point, both packing elements 110 and 120 are set within the wellbore and the portion of the wellbore between the packing elements 110 and 120 is hydraulically isolated from the rest of the

wellbore. Once hydraulically isolated, a downhole job may be executed. For example, that portion of the wellbore may be treated by pumping fluid down the work string 5 and out a ported sub 130 positioned between the packing elements 110 and 120. As discussed above, the first distance separating the third and fourth pin positions 116 and 117 is less than the second distance separating the third and fourth pin positions 126 and 127. In one embodiment, the first distance may be approximately two thirds the second distance.

[0049] After a job has been completed while the packing elements 110 and 120 create seals with the casing 1 of the wellbore, the work string 5 may be moved downwards moving the first pin 113 to the fifth pin position 118 along the first j-track slot 112 of the first sleeve 111, as shown in FIG. 6. The first, or upper, packing element 110 is released, i.e. moved to an unset position, with the movement of the first pin 113 to the fifth pin position 118. The downward movement of the work string 5 moves the second pin 123 back to the third pin position 126 along the second j-slot track 122 of the second sleeve 121 as shown in FIG. 6. Thus, the second, or lower, packing element 120 remains set against the casing 1.

[0050] After the first, or upper, packing element 110 has been released the work string 5 is picked up in the hole moving the first pin 113 to the sixth pin position 119 along the first j-track slot 112 of the first sleeve 111 and moving the second pin 123to the fourth pin position 127 along the second j-track slot 122 of the second sleeve 121, as shown in FIG. 7. The movement of the second pin 123 to the fourth pin position 127 along the second j-track slot 122 unset the second, or lower, packing element 120 of the downhole tool 100.

[0051] The work string 5 may then be pushed down to move the first pin 113 to the first pin position 114 along the first j-track slot 112 of the first sleeve 111 and move the second pin 123 to the first pin position 124 along the second j-track slot 122 of the second sleeve 121 as shown in

FIG. 8. The first pin position 114 along the first j-slot track 112 is axially aligned with the first pin position 124 along the second j-slot track 122 as shown by line 150 in FIG. 8. The tool 100 may now be moved to another desired location in the wellbore. As discussed above, the sleeves 111 and 121 may have been rotated 360 degrees so that the pins 113 and 123 are now back in the first pin positions 114 and 124. Alternatively, the sleeves 111 and 121 may include more than one set of pin positions 114-119 and 124-127 along the length of the sleeves 111 and 121.

[0052] As discussed above, the first j-slot track 111 includes six (6) different pin positions 114-119 and the second j-slot track 121 includes four (4) different pin positions 124-127. Thus, each of the pin positions 114-119 of the first j-slot track 111 do not align with the pin positions 124-127 of the second j-slot track 121. The first pin positions 114 and 124 of each j-slot track 111 and 121 need to be aligned so that the tool 100 may be run into the wellbore or moved to a different location along the wellbore with the packing elements 110 and 120 retain in a running, or unset, position. The pin positions 114-119 along the first j-slot track 111 may be positioned approximately sixty (60) degrees apart from each other and the pin positions 124-127 along the second j-slot track 121 may be positioned approximately ninety (90) degrees apart from each other. Other spacing between the pin positions 114-119 and 124-127 may be used if more than one set of pin positions 114-119 and 124-127 is used around the perimeter of the sleeves 111 and 121 as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure.

[0053] FIG. 9 shows an embodiment of a method 400 of isolating a portion of a wellbore. The method 400 includes the step 410 of running a downhole tool into the wellbore and the step 420 of stopping the tool at a desired location in the wellbore. The method 400 includes the step 430 picking up the work string within the wellbore. As discussed herein, picking up or setting

down the work string moves pins along j-slot tracks to actuate or disengage packing elements of the downhole tool. The method 400 includes the step 440 of setting the lower packer within the wellbore and the step 450 of setting the upper packer within the wellbore. The method 400 optionally includes the step 460 of executing a job with the downhole tool. The job may be the treatment of a portion of the wellbore hydraulically isolated by the set upper and lower packers. The method 400 includes the step 470 of releasing the upper packer and the step 480 of releasing the lower packer. The tool may then be moved within the wellbore and the method 400 may be repeated.

[0054] FIG. 10 shows an embodiment of a downhole tool 200 having a first packing element 210 and a second packing element 220. The first packing element 210 may be an upper packer and the second packing element 220 may be a lower packer. The first and second packing elements 210 and 220 may each comprise a plurality of packing elements configured to create a seal between the tool 200 and casing or tubing of a wellbore. The downhole tool 200 is conveyed into the wellbore via a work string 5 and positioned at a desired location within the wellbore. The packing elements 210 and 220 may be actuated as described herein to selectively hydraulically isolate a portion of the wellbore that may be stimulated, treated, and/or fractured by fluid flowing out of ports 231 of a ported sub 230 located between the two packing elements 210 and 220.

[0055] The tool 200 may include various circulation subs 235 and 265 positioned at various locations along the length of the tool 200 that may circulate fluid out of ports 236 and 266. The circulate subs 235 and 265 may be mechanically actuated and/or electrically actuated to permit circulate of fluid out of the ports 236 and 266. The tool 200 may include various sensors 280 positioned along the length of the tool 200 that may be used to measure downhole conditions

such as pressure and/or temperature. The tool 200 may also include a fluid identification module 285 that may be used to measure various characteristics of the downhole fluid that may be beneficial in analyzing the wellbore. Such characteristics of the fluid may include, but are not limited to, resistivity, capacitance, flow, magnetic resonance, density, or saturation. The sensors 280 or fluid identification module 285 may include optical and/or acoustic sensors. The information from the sensors 280 and/or fluid identification module 285 may be stored within a telemetry and memory sub 245. The data stored within the memory sub 245 may be analyzed when the tool 200 is returned to the surface.

[0056] The tool 200 may include an electrical casing collar locator (CCL) 275 positioned along the length of the tool 200 to aid in determining the location of the tool 200 while within a wellbore. Likewise, the tool 200 may include a mechanical CCL 295 positioned along the length of the tool 200 to aid in determining the location of the tool 200 while within a wellbore. The tool 200 may include a single CCL both a mechanical CCL 295 and an electrical CCL 275. The tool 200 may include various quick disconnect subs 240 positioned along the length of the tool 200 to aid in removal of at least a portion of the tool 200 in the event the tool 200 becomes stuck within a wellbore. The tool 200 may include a sand jet perforating sub 290 having ports 291. The sand jet perforating sub 290 may be used to perforate casing and/or tubing within a wellbore.

[0057] As discussed herein, the packing elements 210 and 220 of the downhole tool 200 are actuated by movement along two j-track slots 212 and 222. A portion of an upper j-track slot 212 is shown in FIG. 10 extending beyond an upper rotating sub 211 of the tool 200. Likewise, a portion of a lower j-track slot is shown in FIG. 10 extending beyond a lower rotating sub 221 of the tool. The rotating subs 211 and 221 rotate to move through the various positions along the j-

track slots 212 and 222 to actuate and unset the packing elements 210 and 220 as described herein. The rotating subs 211 and 221 may also be referred to as rotating sleeves as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure.

[0058] The tool 200 may include a slip joint 270 positioned between the upper and lower packing elements 210 and 220. The slip joint 270 permits the lengthening of the distance between the lower packing element 220 and the upper packing element 210 while the upper packing element 210 is being set within the wellbore. As detailed herein, the lower packing element 220 is set within the wellbore before the upper packing element 210 is set. The lengthening of the distance between the packing elements 210 and 220 may aid in preventing the lower packing element 220 from becoming unset during the setting of the upper packing element 210. The rotating subs 211 and 221 may include slips 234 and drag blocks 233 that aid in the setting of the packing elements 210 and 220 within the wellbore.

[0059] FIG. 11A shows an embodiment of a downhole tool 300 having a first packing element 310 and a second packing element 320. The first packing element 310 may be an upper packer and the second packing element 320 may be a lower packer. The first and second packing elements 310 and 320 may each comprise a plurality of packing elements configured to create a seal between the tool 300 and casing 1, or tubing, of a wellbore. The downhole tool 300 is conveyed into the wellbore via a work string 5 and positioned at a desired location within the wellbore. For example, the downhole tool 300 may be positioned adjacent a perforation(s) 2 in the casing 1. The wellbore may then be treated via the tool 300 as discussed herein. The work string 5 may be various strings as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure. FIG. 1A shows the packing elements 310 and 320 in a running position, *i.e.* a retracted or unset orientation, so that the tool 300 may be moved through the

casing or tubing 1 of the wellbore. The tool 300 includes a ported sub 130 having one or more flow ports 131 and a quick disconnect sub 140 that are described herein.

[0060] FIG. 11B shows the second, or lower, packing element 320 set against the casing 1 of the wellbore to create a seal between the tool 300 and the casing 1. The second packing element 320 may be set in tension by the rotation of a sleeve or rotating sub connected to the second packing element 320. FIG. 11C shows the first, or upper, packing element 310 set against the casing 1 of the wellbore to create a seal between the tool 300 and the casing 1. The first packing element 310 may be set in compression by the rotation of a sleeve or rotating sub connected to the first packing element 310. The rotating subs and j-tracks may be configured as to set the lower packing element 320 in tension and the upper packing element 310 in compression as would be appreciated by one ordinary skill in the art having the benefit of this disclosure.

[0061] The setting of the first and second packing elements 310 and 320 hydraulically isolates the portion of the wellbore between the packing elements 310 and 320 from the rest of the wellbore. FIG. 11D shows the treatment of the wellbore by flowing fluid out of the flow ports 131 of the ported sub 130 as shown by arrows 132. The formation of the wellbore may be treated via perforations 2 through the casing 1. Fluid is pumped down the work string 5 and out the ports 131 of the ported sub 130. After the portion of the wellbore has been treated, the packing elements 310 and 320 may be unset, i.e. moved to their running position, and the tool 300 may be moved to another location within the wellbore. Treating the wellbore formation may comprise various applications such as stimulating or fracturing the formation as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure. The quick disconnect sub 140 permits the upper portion of the tool 100 to be disconnected from the second packing element 320 to the extent the tool 300 becomes stuck within the wellbore. The upper

portion of the tool 300 and the work string 5 may then be removed from the wellbore. The lower portion of the tool 300 may then be fished out of the wellbore. Alternatively, the lower portion of the tool 300 may be drilled out or simply pushed to the bottom of the wellbore.

[0062] FIG. 12 shows one embodiment of a slip joint 500 that may be used in a downhole tool 100, 200, or 300 having an upper packer 110, 210, or 310 and a lower packer 120, 220, or 320. As discussed above in regards to slip joint 170, the slip joint 500 of FIG. 12 permits the lengthening of the distance between the lower packing element 120, 220, or 320 and the upper packing element 110, 210, or 310 while the upper packing element 110, 210, or 310 is being set within the wellbore. The slip joint 500 is energized such that the slip joint 500 may provide a force to the lower packer 120, 220, or 320 while the upper packer 110, 210, or 310 is being set. The force applied to the lower packer 120, 220, or 320 may help prevent the lower packer 120, 220, or 320 from becoming unset from the wellbore as the upper packer 110, 210, or 310 is being set.

[0063] The slip joint 500 includes an upper portion 510 and a lower portion 520 that are configured to move relative to each other to change the length between the packing elements as discussed above. A portion 521 of the lower portion 520 may be configured to move inside of the upper portion 510 decreasing a distance between a shoulder 515 of the upper portion 510 and a shoulder 525 of the lower portion 520. The slip joint 500 may be energized by a resilient member 530 positioned between the shoulders 515 and 525. As the distance between the shoulders 515 and 525 is decreased the resilient member 530 is compressed. The compression of the resilient member 530 imparts a force against the lower packer 120, 220, or 320 that is set against the wellbore. The force against the lower packer 120, 220, or 320 from the energized slip

joint 500 may prevent the lower packer 120, 220, or 320 from unsetting from the wellbore as the upper packer 110, 210, or 310 is being set.

[0064] FIG. 13 shows a cross-section of an embodiment of a slip joint 500 that may be used in a downhole tool 100, 200, or 300 to change the distance between the upper packer 110, 210, or 310 and the lower packer 120, 220, or 320. A portion 521 of the lower portion 520 of the slip joint 500 extends into a bore 511 of the upper portion 510 of the slip joint 500. A resilient member 530 may be positioned between a first shoulder 515 and a second shoulder 525. The movement of the lower portion 520 with respect to the upper portion 510 compresses the resilient member 530 and energizes the slip joint 500. The force from the compressed resilient member 530 may be applied to the lower packing element 120, 220, or 320 as discussed above. The resilient member 530 may be various members that impart a force when compressed. For example, the resilient member may be any elastic object used to store mechanical energy, such as a spring or a series of springs, as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure. The resilient member 530 may be comprised of several springs having different stiffness, or spring factor K, so that the force provided by the resilient member 530 is not linear when compressed.

[0065] FIG. 14 shows an embodiment of a slip joint 600 that includes an internal chamber 626 that energizes the slip joint 600. The movement between the upper portion 610 and lower portion 620 of the slip joint 600 may compress or decrease the volume of the chamber 626 causing the slip joint 600 to impart a force that may be applied a portion of the tool 100 such as the lower packing element 120, 220, or 320. Various mechanisms may be used to energize the slip joint 600 by the compression, or reduction in volume, of the chamber 626. For example, the slip joint 600 may include a resilient member 630 positioned within the chamber 626 that is

compressed by shoulders 621 and 627 as a portion 611 of the upper portion 610 of the slip joint 600 moves within the chamber 626. Alternatively, the slip joint 600 could be hydraulically or pneumatically energized as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure. For example, the chamber 626 could be hydraulically or pneumatically pressurized with the compression of the chamber 626 causing the slip joint 600 to be energized in impart a force to the lower packing element 120, 220, or 320. The configuration and energizing mechanisms of the slip joint 500 and 600 are for illustrative purposes only and may be varied as would be appreciated by one of ordinary skill in the art having the benefit of this disclosure.

[0066] FIG. 15 shows an embodiment of a method 700 of isolating a portion of a wellbore. The method 700 includes the step 710 of running a downhole tool into the wellbore and the step 720 of stopping the tool at a desired location in the wellbore. The method 700 includes the step 730 picking up the work string within the wellbore. As discussed herein, picking up or setting down the work string moves pins along j-slot tracks to actuate or disengage packing elements of the downhole tool. The method 700 includes the step 740 of setting the lower packer within the wellbore, the step 750 of applying a force to the lower packer from an energized slip joint, and the step 760 of setting the upper packer within the wellbore. As discussed above, the force applied to the lower packer from the energized slip joint may prevent the lower packer from being unset from the wellbore during step 760 of setting the upper packer. The method 700 optionally includes the step 770 of executing a job with the downhole tool. The job may be the treatment of a portion of the wellbore hydraulically isolated by the set upper and lower packers. The method 700 includes the step 780 of releasing the upper packer and the step 790 of releasing

the lower packer. The tool may then be moved within the wellbore and the method 700 may be repeated.

[0067] Although this disclosure has been described in terms of certain preferred embodiments, other embodiments that are apparent to those of ordinary skill in the art, including embodiments that do not provide all of the features and advantages set forth herein, are also within the scope of this invention. Accordingly, the scope of the present disclosure is defined only by reference to the appended claims and equivalents thereof.

What is claimed is:

1. A dual packer comprising:

a first packing element movable between a set position and a running position;

a second packing element movable between a set position and a running position; and

a slip joint positioned between the first packing element and the second packing element, wherein the slip joint is configured to change a length between the first and second packing elements.

2. The dual packer of claim 1, wherein the slip joint is energized.

3. The dual packer of claim 2, wherein the slip joint is comprised of an upper portion and a lower portion, the upper and lower portions move relative to one another to change the length between the first and second packing element.

4. The dual packer of claim 3, wherein a resilient member positioned between a shoulder of the upper portion and a shoulder of the lower portion energizes the slip joint.

5. The dual packer of claim 2, wherein the energized slip joint applies a force on the second packing element when the second packing element is in the set position.

6. The dual packer of claim 5, wherein the slip joint is energized by a resilient member.

7. The dual packer of claim 5, the slip joint further comprising a chamber, wherein the chamber energizes the slip joint.

8. The dual packer of claim 7, wherein the chamber is hydraulically or pneumatically pressurized.

9. The dual packer of claim 7, wherein the slip joint is energized by a resilient member positioned within the chamber.

10. The dual packer of claim 5, further comprising:

a first sleeve having a first j-slot track, wherein movement of a first pin along the first j-slot track actuates the first packing element between the set position and the running position; and

a second sleeve having a second j-slot track, wherein movement of a second pin along the second j-slot track actuates the second packing element between the set position and the running position.

11. A system to isolate and treat a portion of a wellbore comprising:

an upper packer;

a first sleeve having a j-slot track, wherein movement of a first pin along the j-slot track of the first sleeve actuates the upper packer between a set position and a running position;

a lower packer;

a second sleeve having a j-slot track, wherein movement of a second pin along the j-slot track of the second sleeve actuates the lower packer between a set position and a running position;

a ported sub being connected between the upper packer and the lower packer; and

a slip joint being connected between the upper packer and the lower packer, the slip joint is configured to change a length between the upper and lower packers.

12. The system of claim 11, wherein the slip joint is energized to provide a force on the lower packer when the lower packer is in the set position.

13. The system of claim 12, wherein the slip joint is energized hydraulically, pneumatically, or by a resilient member.

14. The system of claim 12, further comprising a work string connected to the upper packer, wherein fluid may be pumped down the work string and out the ported sub.

15. A method of isolating a portion of a wellbore comprising:

running a tool on a work string into a wellbore;

positioning the tool adjacent a portion of the wellbore;

picking up the work string;

setting a lower packer of the tool;

applying a force to the set lower packer; and

setting an upper packer of the tool after setting the lower packer.

16. The method of claim 15, further comprising treating a formation of the wellbore through a port in a tubular.

17. The method of claim 16, wherein treating the formation of the wellbore further comprises at least one of fracturing, re-fracturing, stimulating, tracer injection, cleaning, acidizing, steam injection, water flooding, and cementing.

18. The method of claim 16, further comprising releasing the upper packer of the tool and releasing the lower packer of the tool after releasing the upper packer.

19. The method of claim 15, wherein an energized slip joint applied the force to the set lower packer.

20. The method of claim 19, wherein a resilient member energizes the slip joint.

21. The method of claim 20, wherein the resilient member is positioned between two shoulders of the slip joint.

22. The method of claim 19, wherein the slip joint is energized hydraulically or pneumatically.

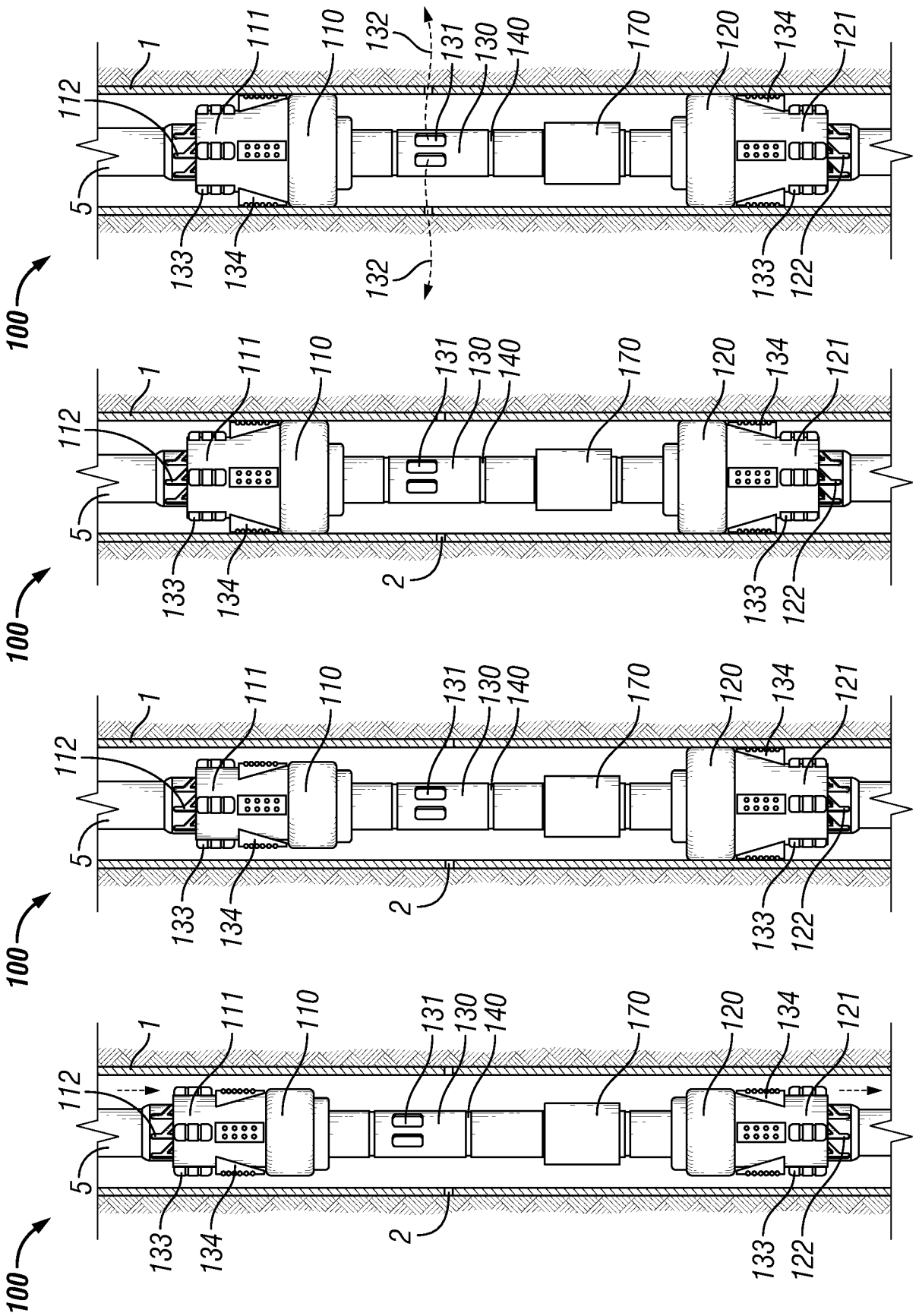

FIG. 1A

FIG. 1B

FIG. 1C

FIG. 1D

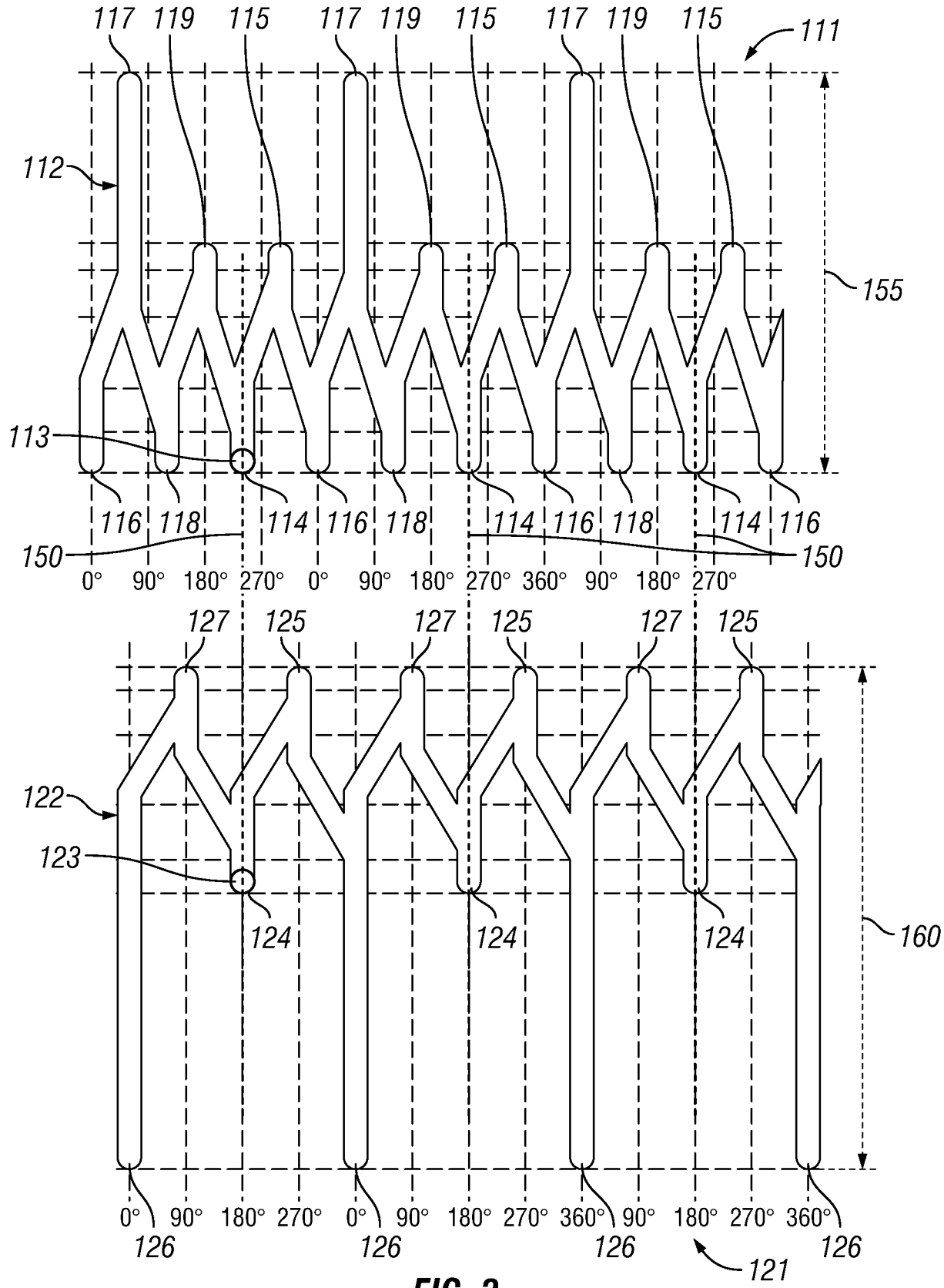
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FIG. 2

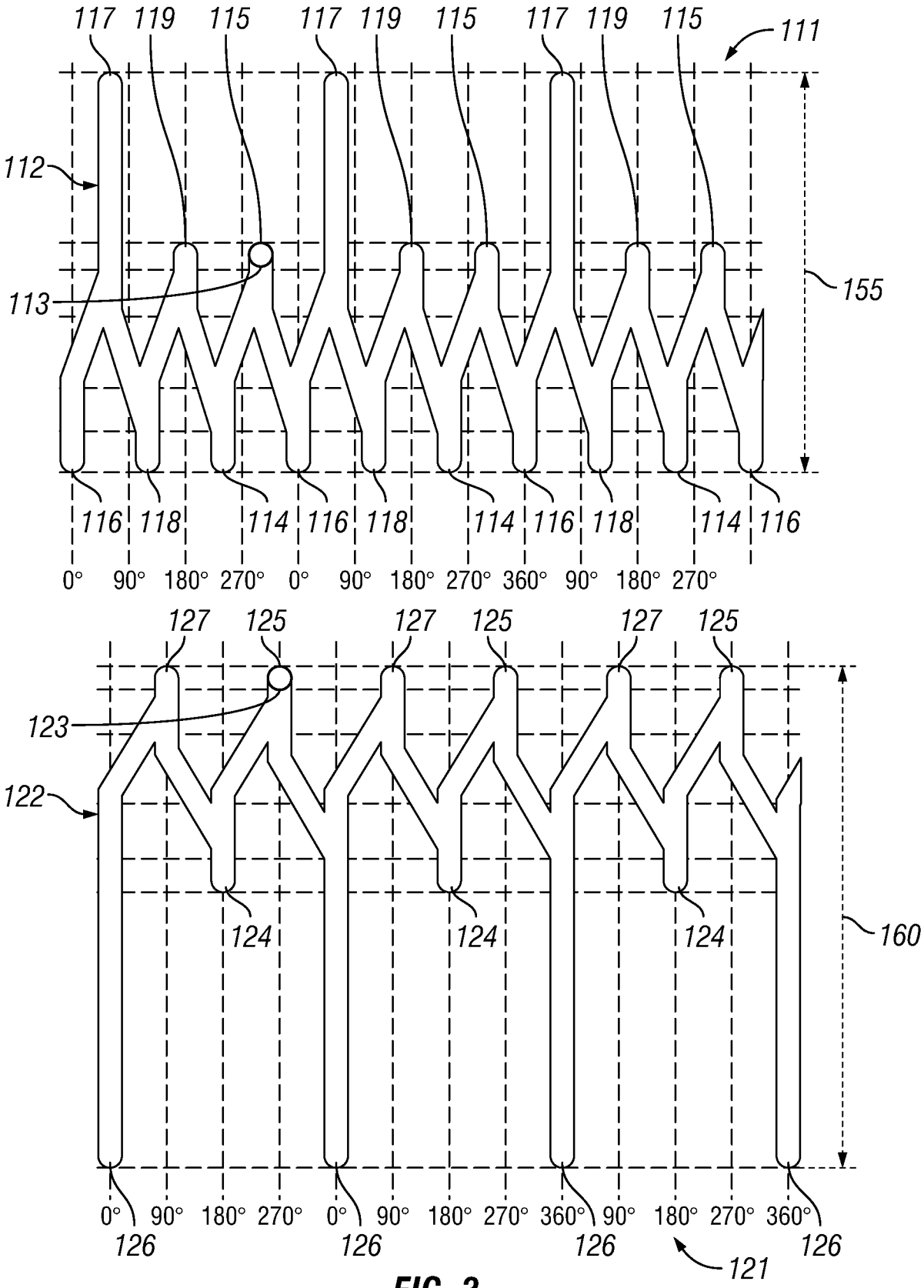
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FIG. 3

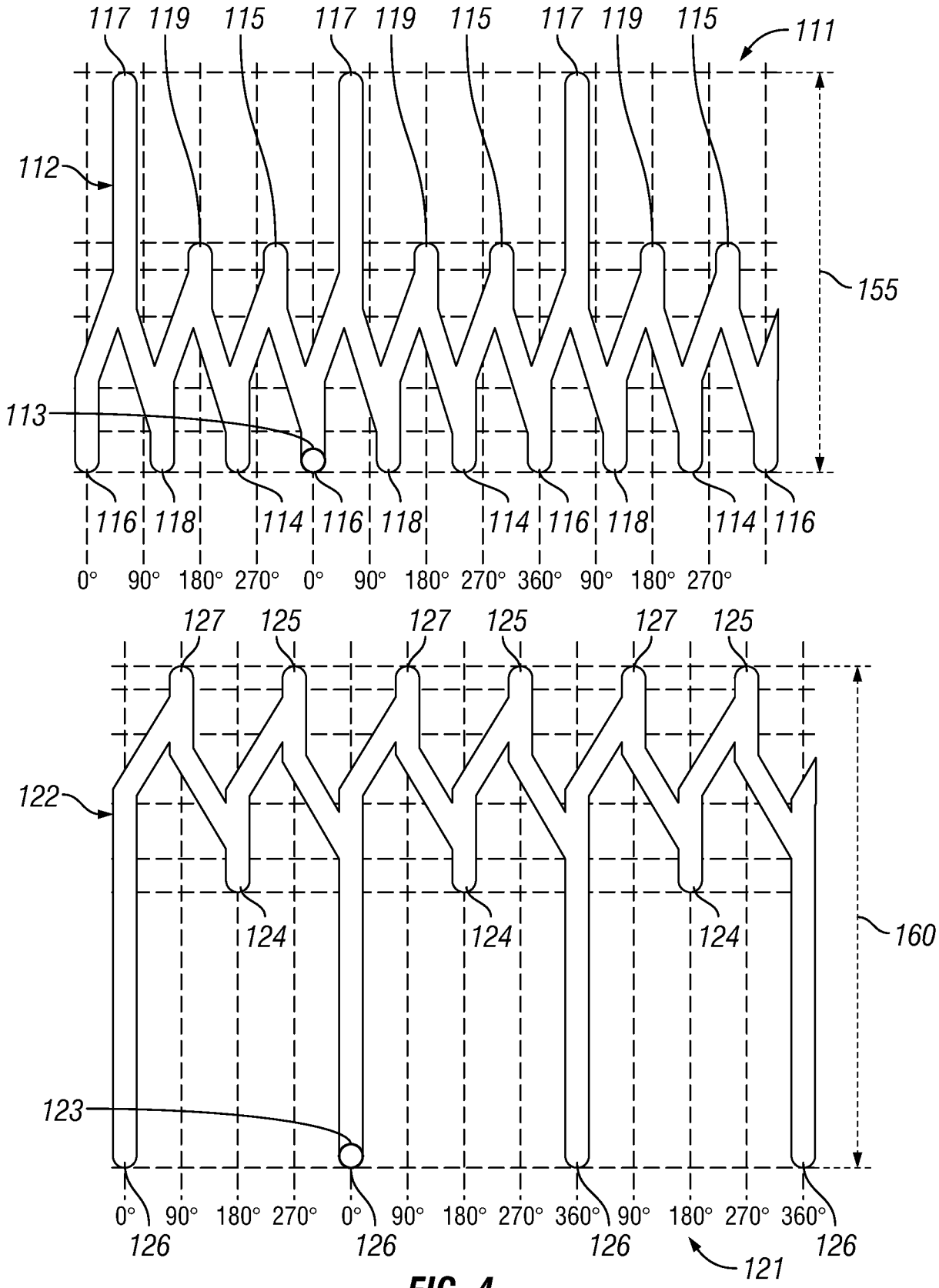
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FIG. 4

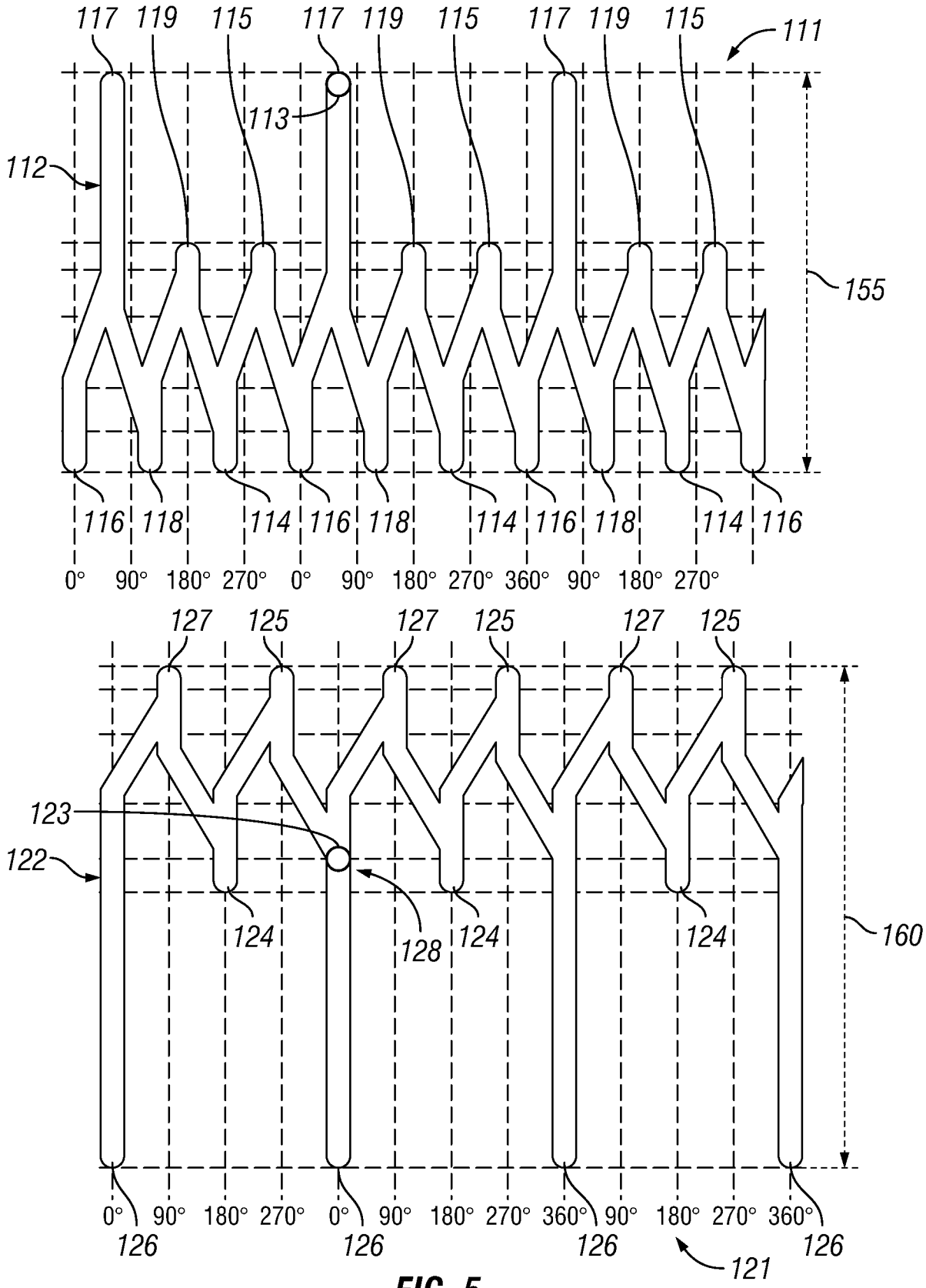
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FIG. 5

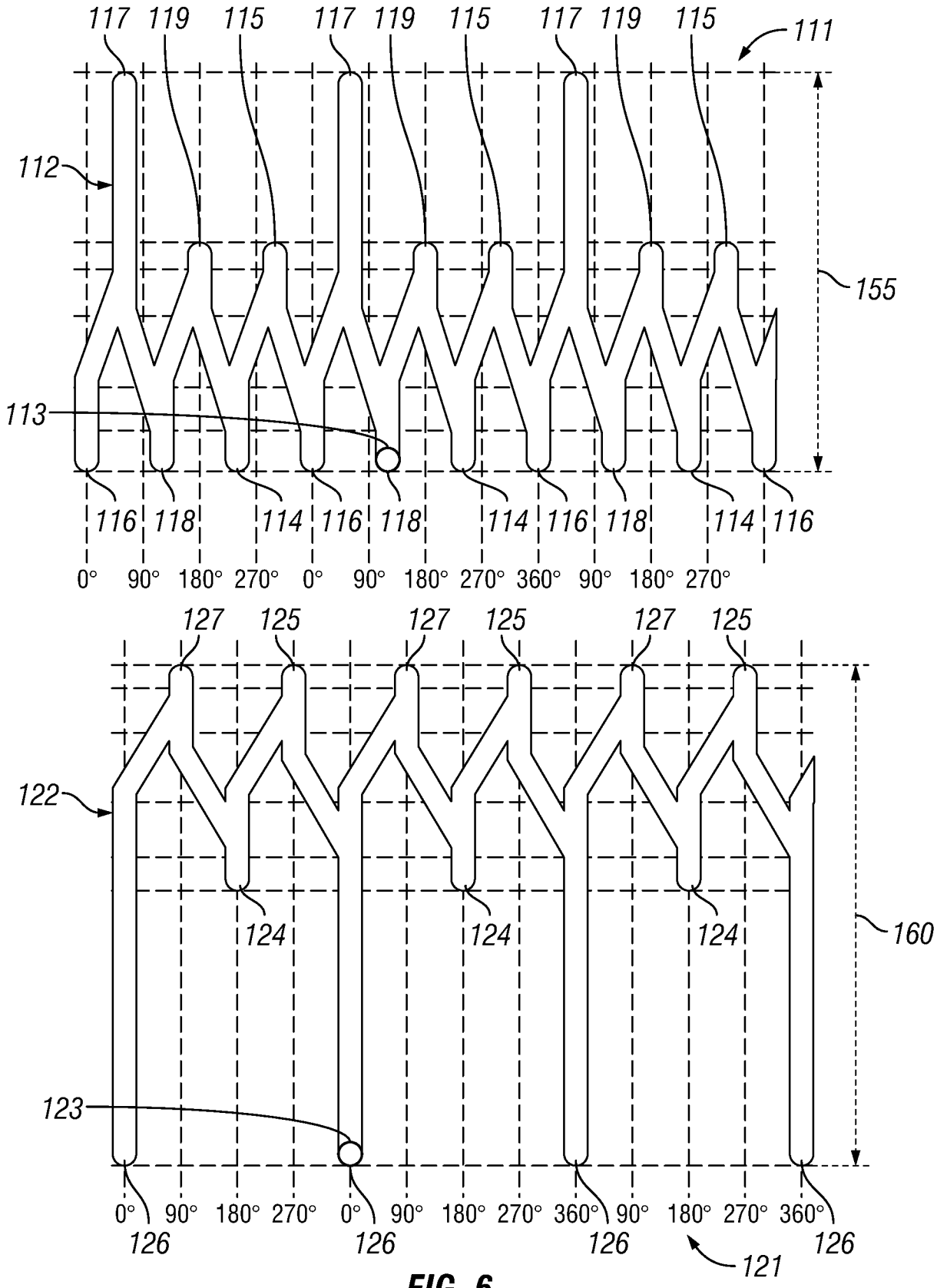
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FIG. 6

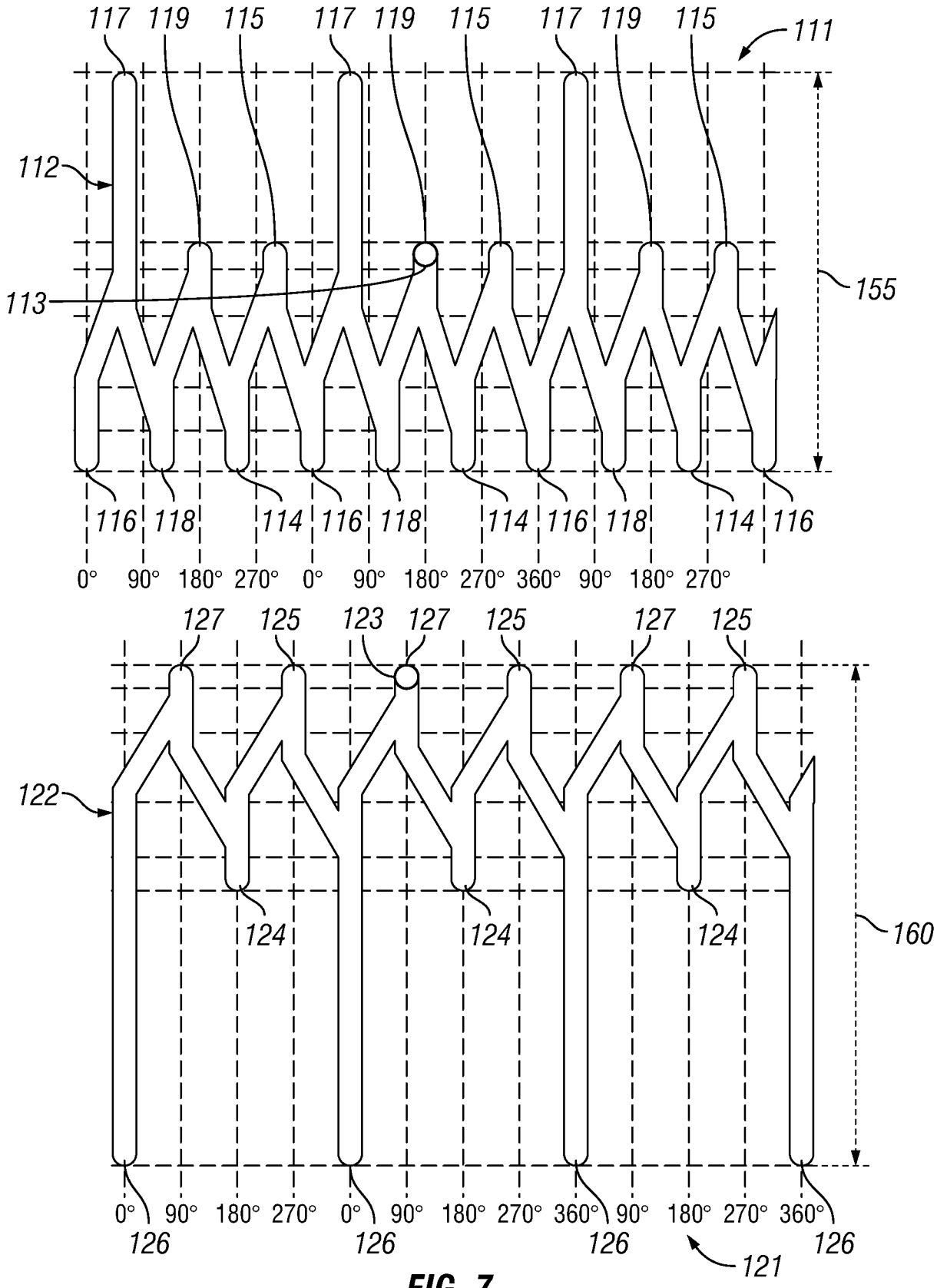
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FIG. 7

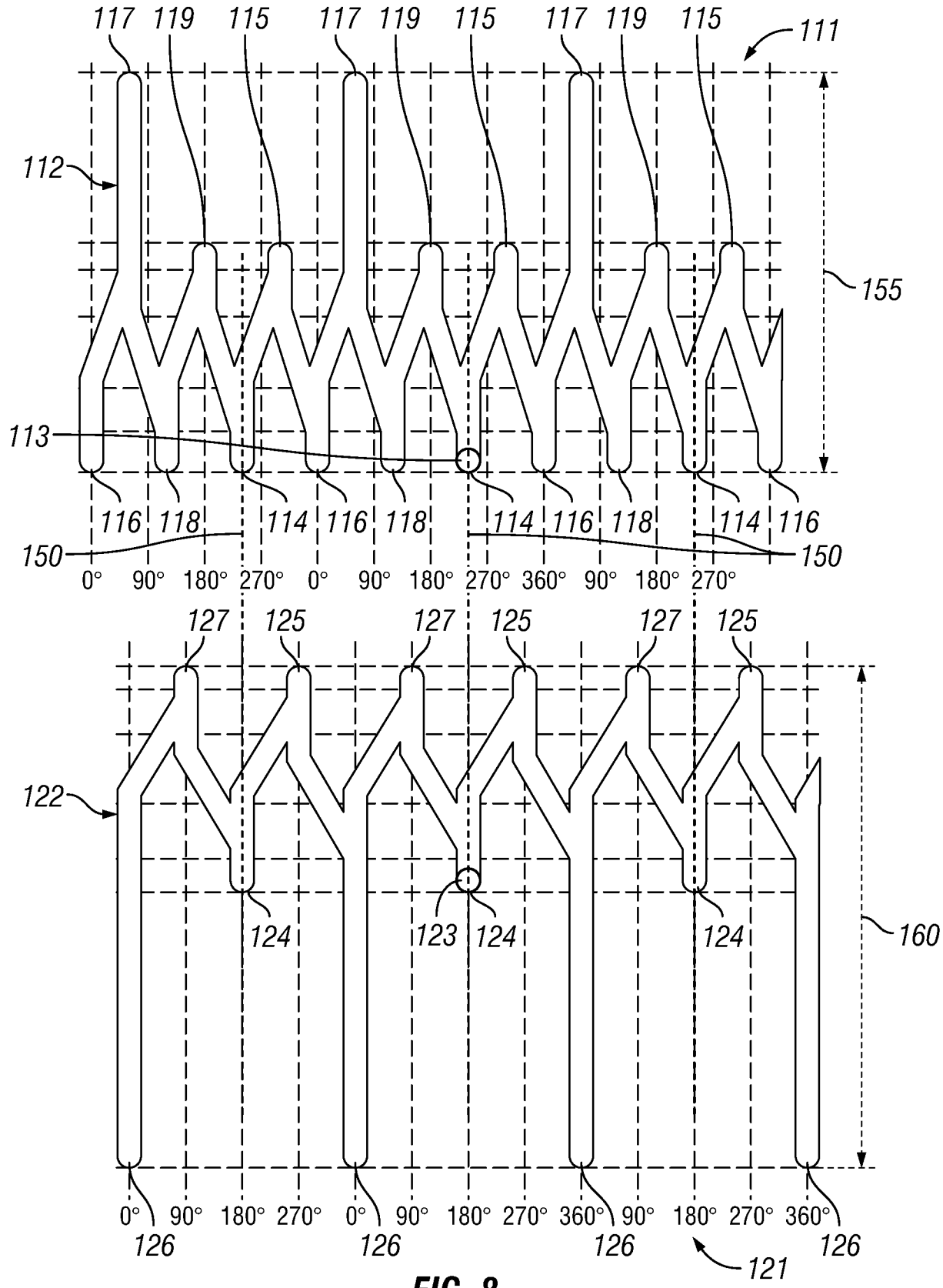
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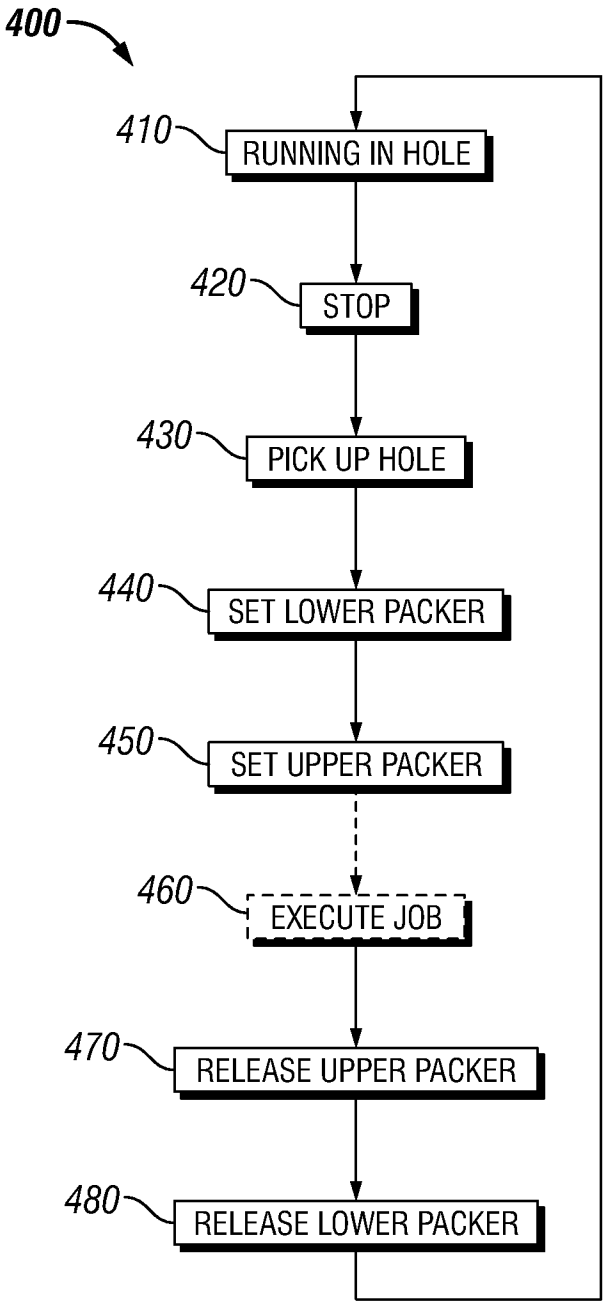
FIG. 8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STOP
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PICK UP HOLE
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SET LOWER PACKER
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SET UPPER PACKER
460
EXECUTE JOB
470
RELEASE UPPER PACKER
480
RELEASE LOWER PACKER

FIG. 9

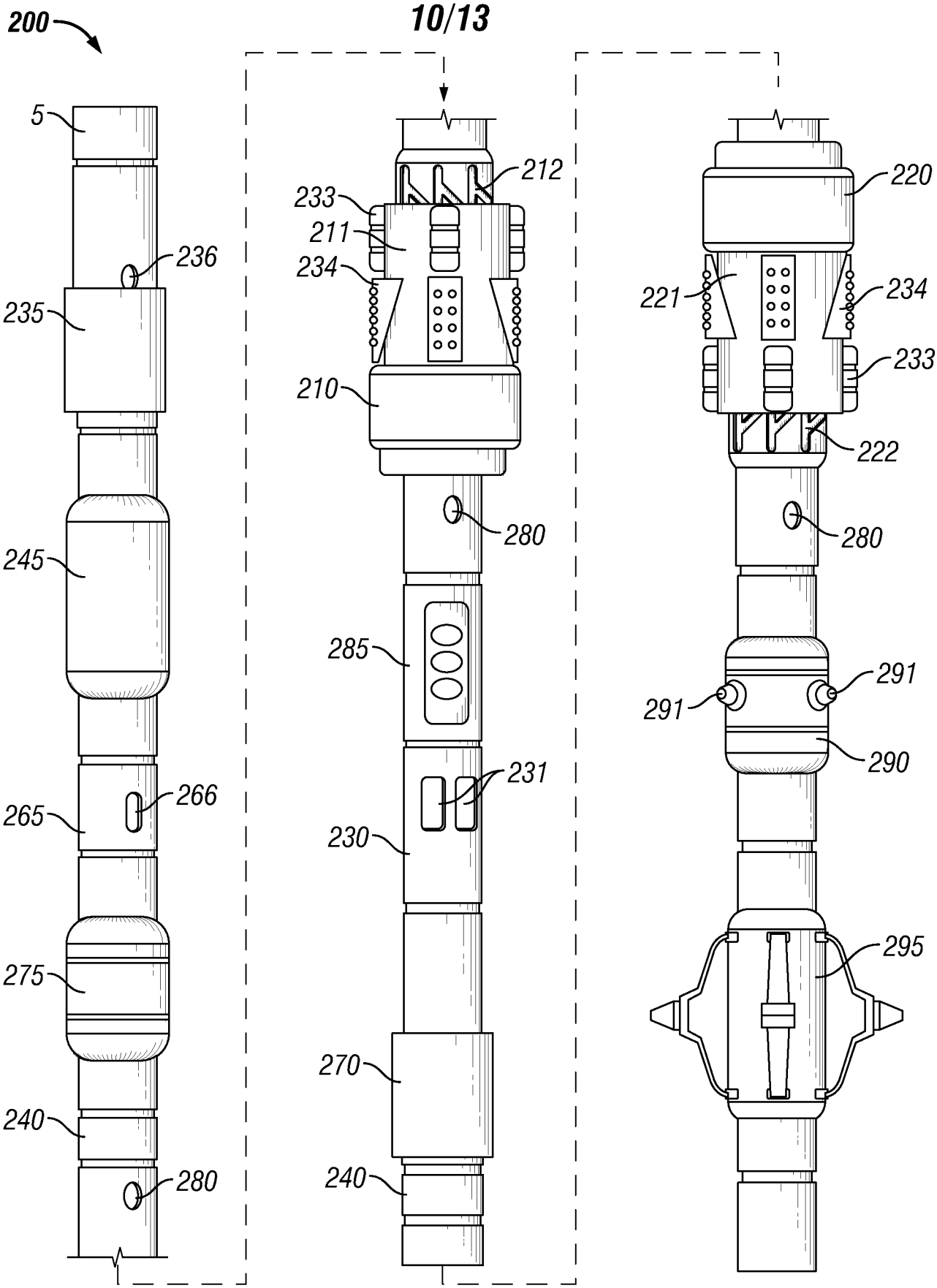
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FIG. 10

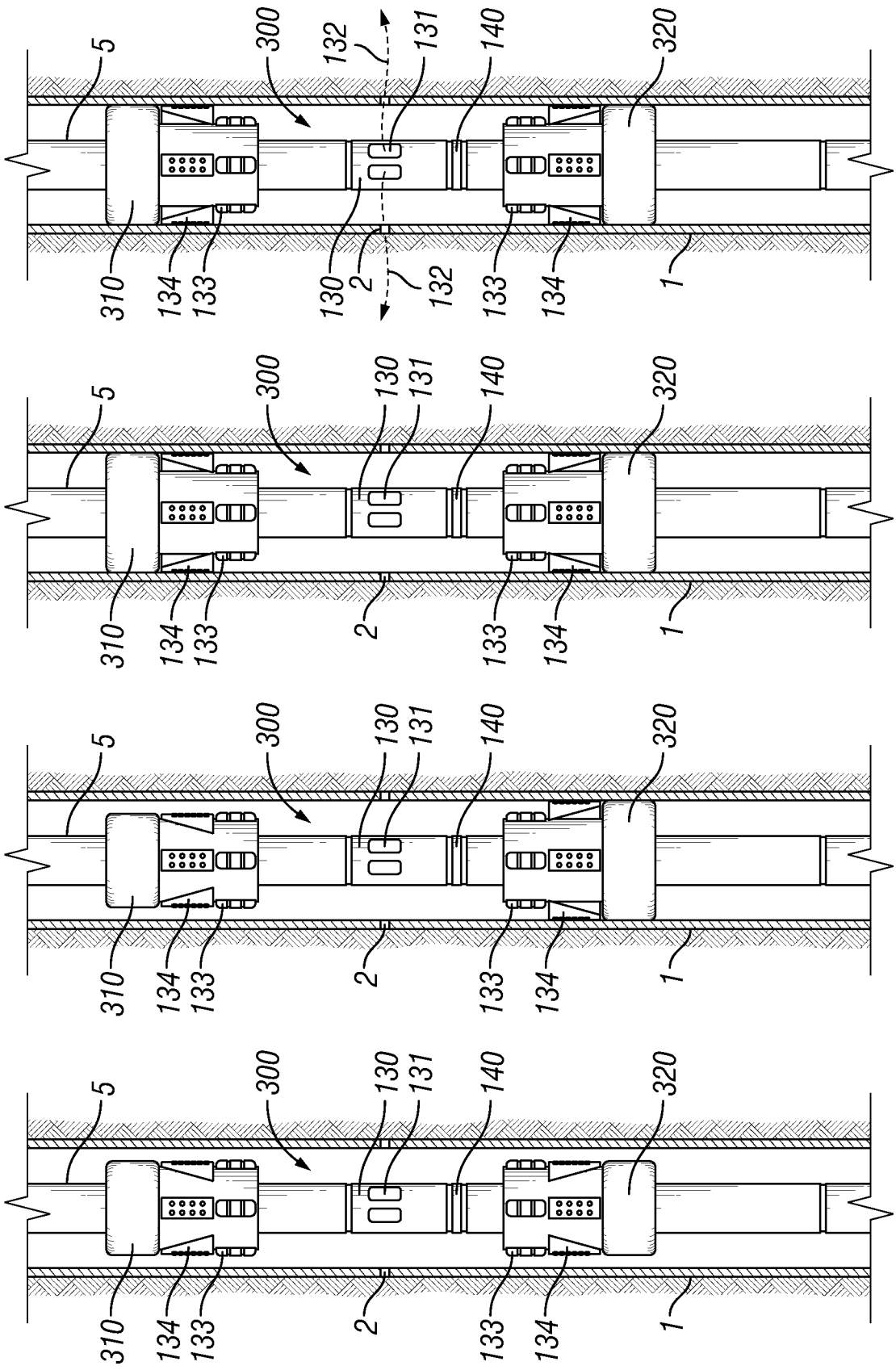

FIG. 11D

FIG. 11C

FIG. 11B

FIG. 11A

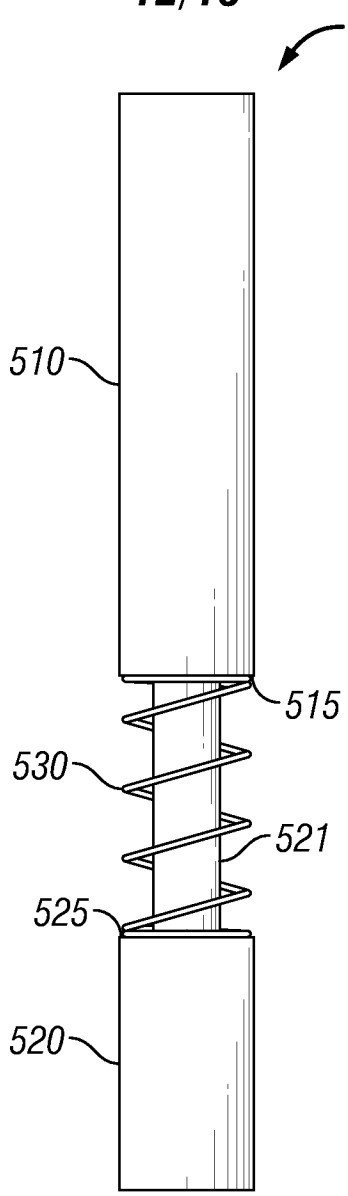

FIG. 12

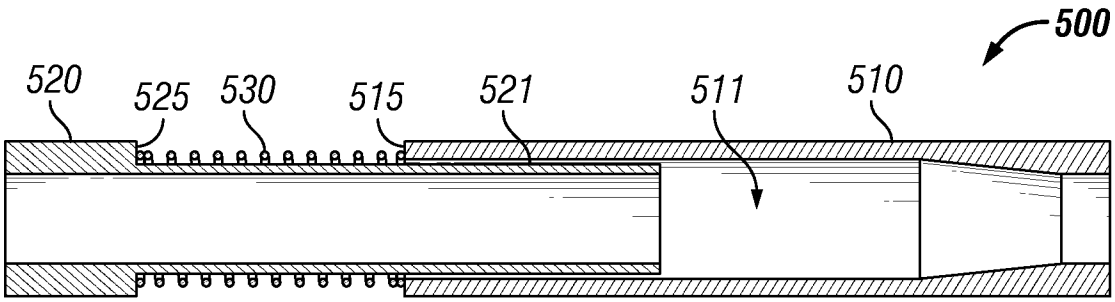

FIG. 13

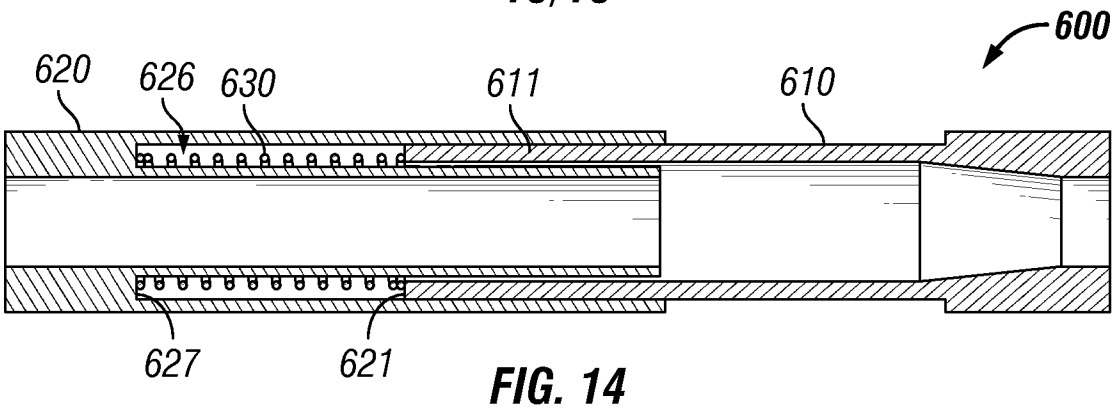
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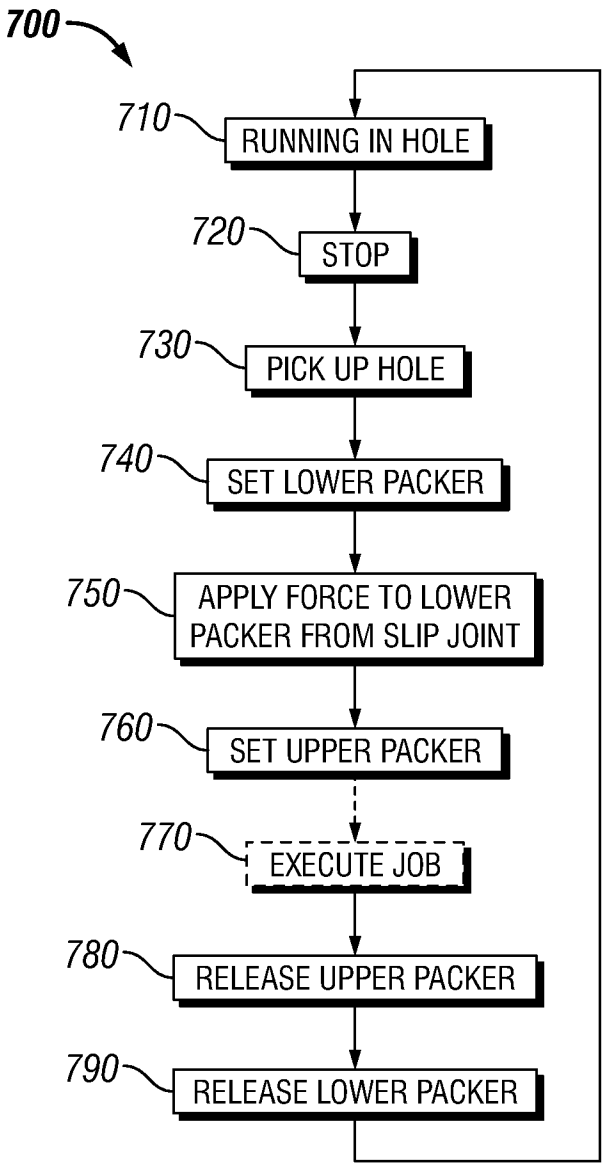
FIG. 14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STOP
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PICK UP HOLE
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SET LOWER PACKER
750
APPLY FORCE TO LOWER PACKER FROM SLIP JOINT
760
SET UPPER PACKER
770
EXECUTE JOB
780
RELEASE UPPER PACKER
790
RELEASE LOWER PACKER

FIG. 15

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2016/030728

A. CLASSIFICATION OF SUBJECT MATTER

E21B 33/12(2006.01)i, E21B 33/124(2006.01)i, E21B 33/127(2006.01)i, E21B 23/06(2006.01)i

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B 33/12; E21B 23/06; E21B 33/124; E21B 43/26; E21B 33/127

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & Keywords: dual packer, slip joint, change, length, resilient member, chamber, and j-slot track

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2008-0053652 A1 (CORRE et al.) 06 March 2008 See paragraphs [0022], [0035]-[0036], [0038]-[0039] and figures 4A-4C, 5C, 7A-7D.	1-9
Y		15-22
A		10-14
Y	US 6926088 B2 (TINKER, DONALD W.) 09 August 2005 See column 4, lines 12-49 and figures 5-5A.	15-22
A	US 5178219 A (STRIECH et al.) 12 January 1993 See column 3, line 50 - column 4, line 8 and figures 1-2.	1-22
A	WO 2010-089558 A2 (HALLIBURTON ENERGY SERVICES, INC. et al.) 12 August 2010 See paragraph [0035] and figure 8.	1-22
A	US 2002-0062962 A1 (GARY et al.) 30 May 2002 See paragraphs [0031]-[0032] and figures 1-2, 6.	1-22

☐ Further documents are listed in the continuation of Box C. ☒ See patent family annex.

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents,such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
09 August 2016 (09.08.2016)	**09 August 2016 (09.08.2016)**

Name and mailing address of the ISA/KR
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