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Rodriguez et al.

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(54) **WHIPSTOCK WITH DETACHABLE WHIPFACE AND SEALING CAPABILITIES FOR MULTILATERAL SYSTEMS**

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(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 0 days.

(21) Appl. No.: **18/097,713**

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(65) **Prior Publication Data**

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Related U.S. Application Data

(60) Provisional application No. 63/300,539, filed on Jan. 18, 2022.

(51) **Int. Cl.**

E21B 41/00	(2006.01)
E21B 7/06	(2006.01)
E21B 17/20	(2006.01)
E21B 23/12	(2006.01)

(52) **U.S. Cl.**

CPC ***E21B 41/0035*** (2013.01); ***E21B 7/061*** (2013.01); ***E21B 17/20*** (2013.01); ***E21B 23/12*** (2020.05); ***E21B 41/0042*** (2013.01)

(58) **Field of Classification Search**

CPC E21B 41/0042; E21B 7/061; E21B 17/046; E21B 29/06; E21B 34/063; E21B 41/0035; E21B 43/08; E21B 17/20; E21B 23/12

See application file for complete search history.

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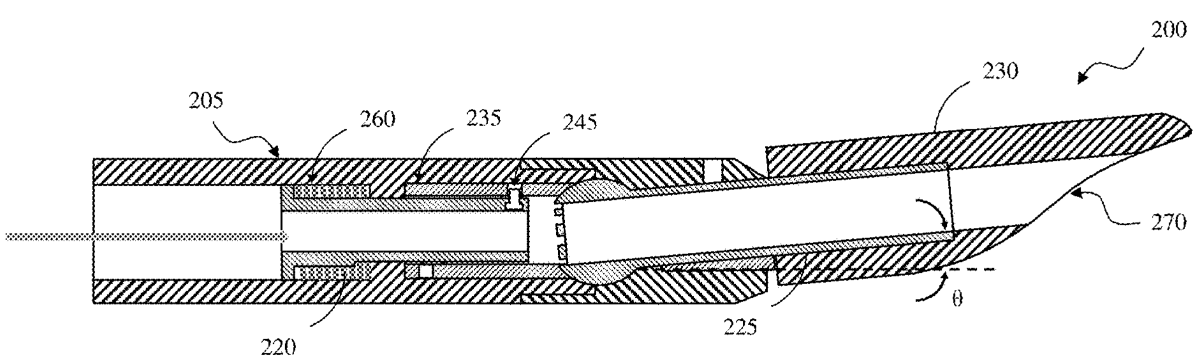
Primary Examiner — Brad Harcourt

(74) *Attorney, Agent, or Firm* — Scott Richardson; Parker Justiss, P.C.

(57) **ABSTRACT**

Provided is a whipstock, a well system, and a method. The whipstock, in at least one aspect, includes a whipface having an angled casing string exit surface, a sub detachably coupled to the whipface, and a bottom hole assembly fixedly coupled to the sub, the bottom hole assembly having one or more seals along an inner surface thereof.

32 Claims, 77 Drawing Sheets



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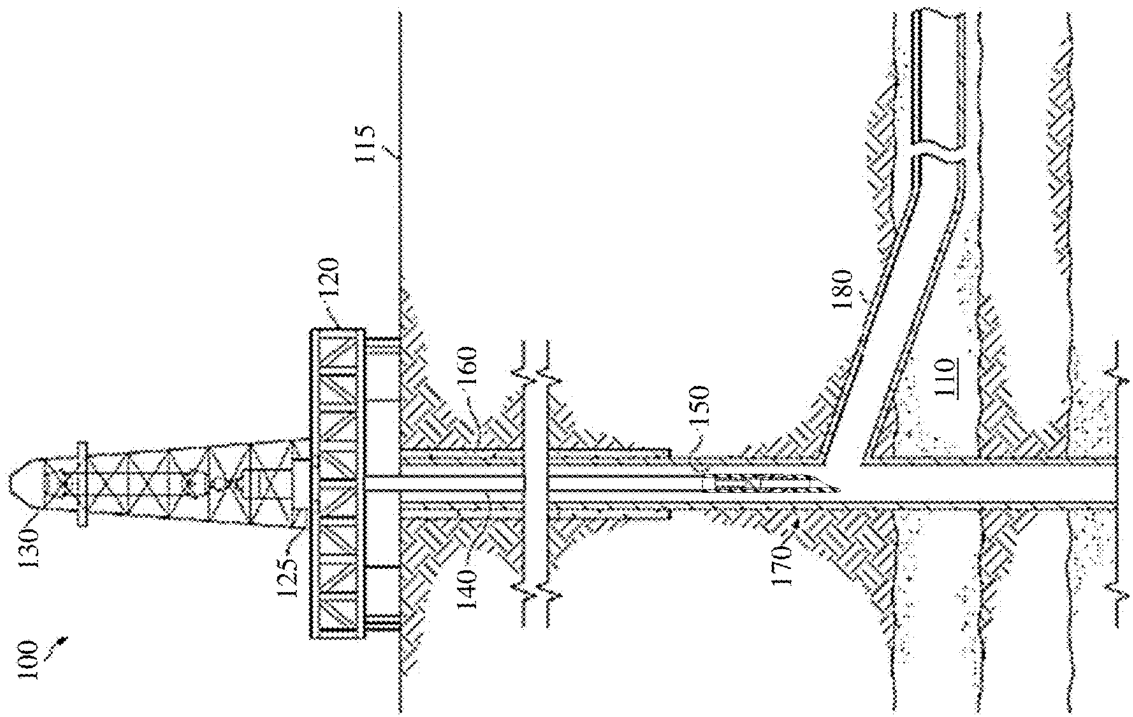


FIG. 1

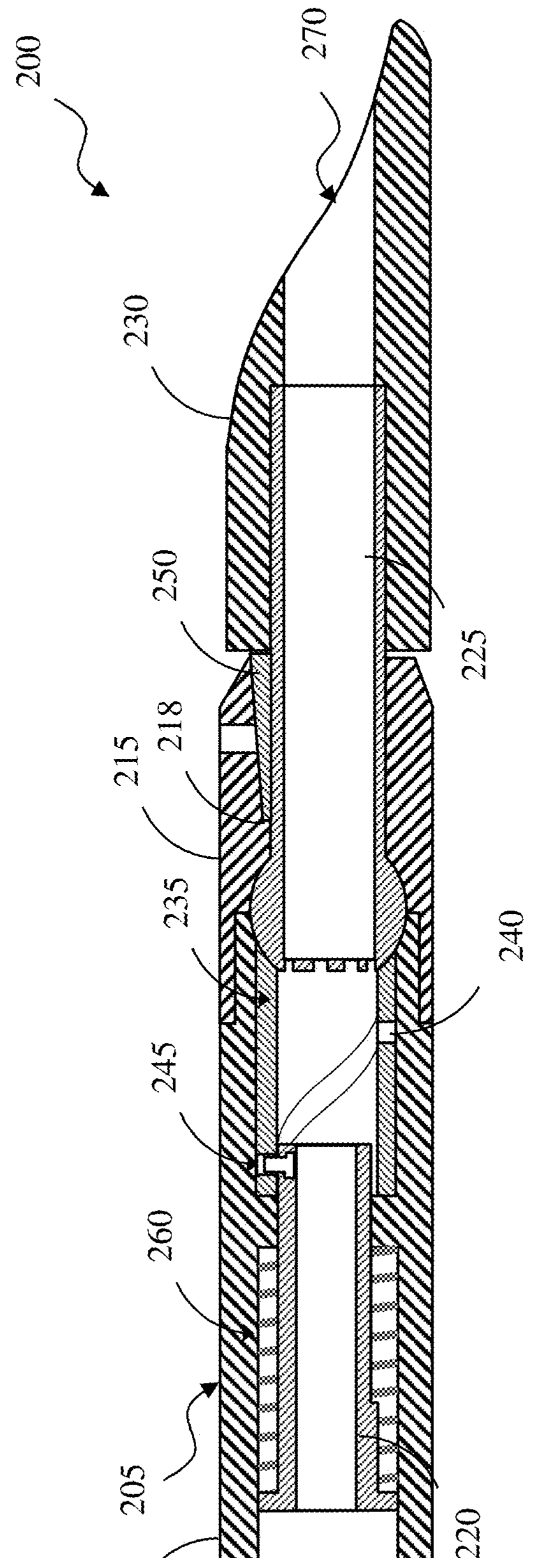
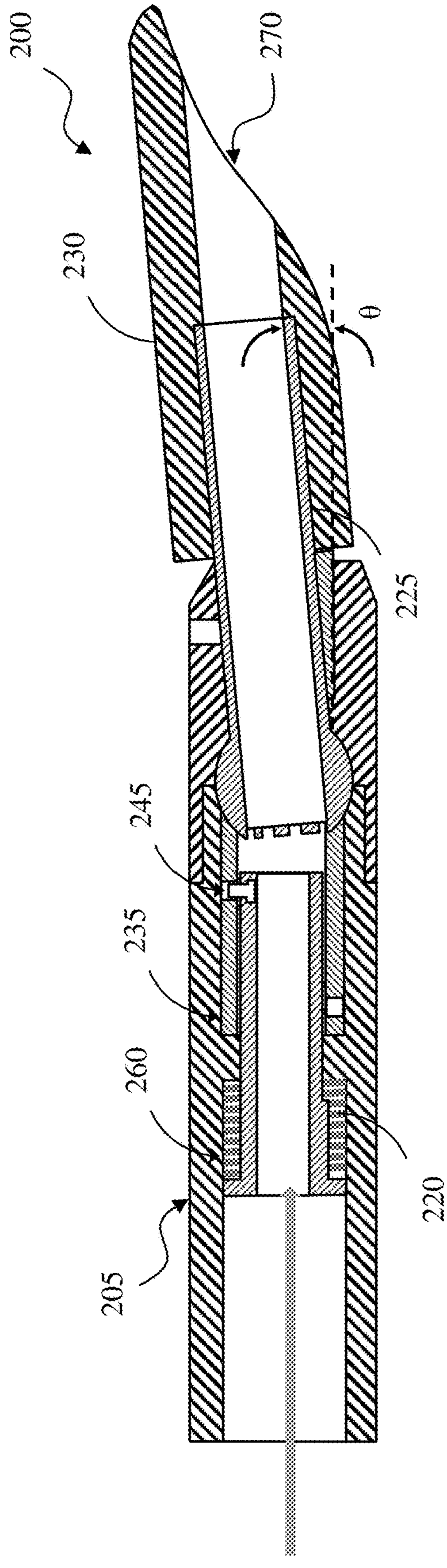


FIG. 2A



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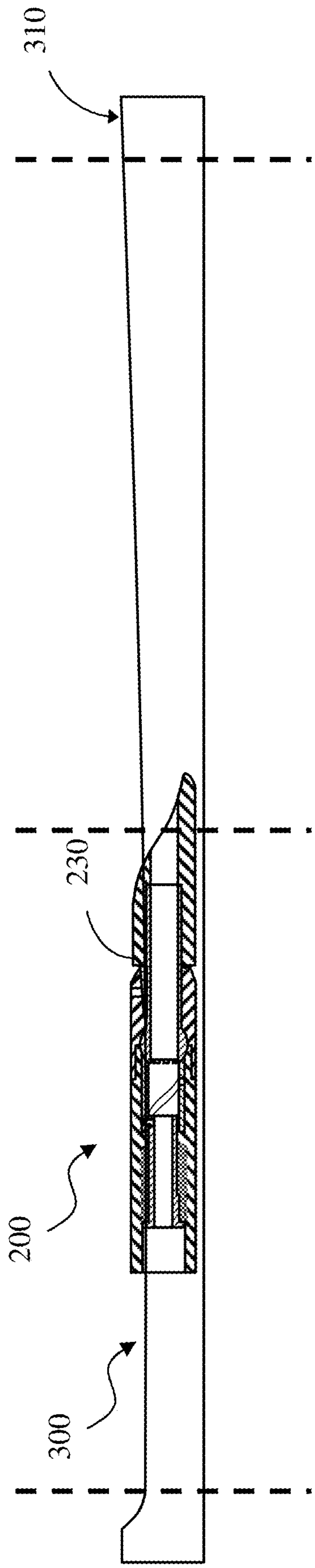
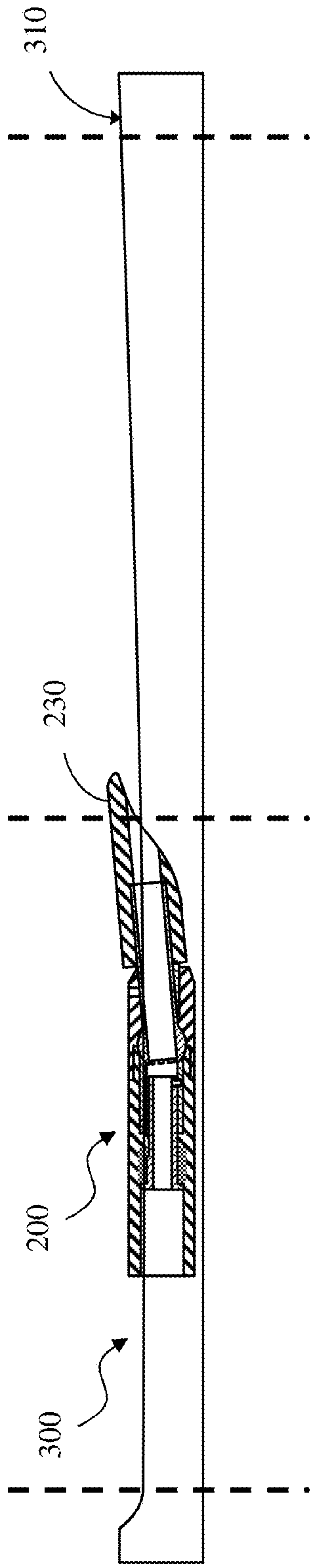


FIG. 3A



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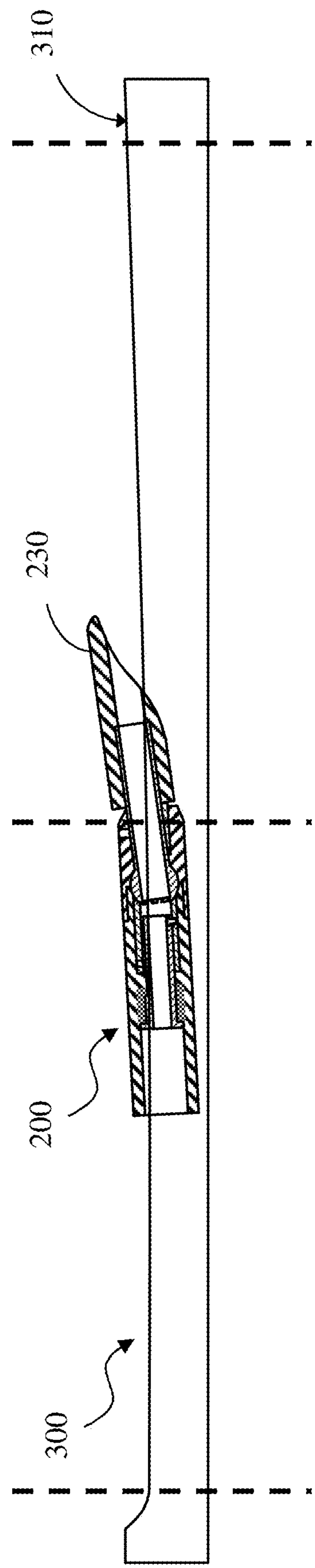


FIG. 3C

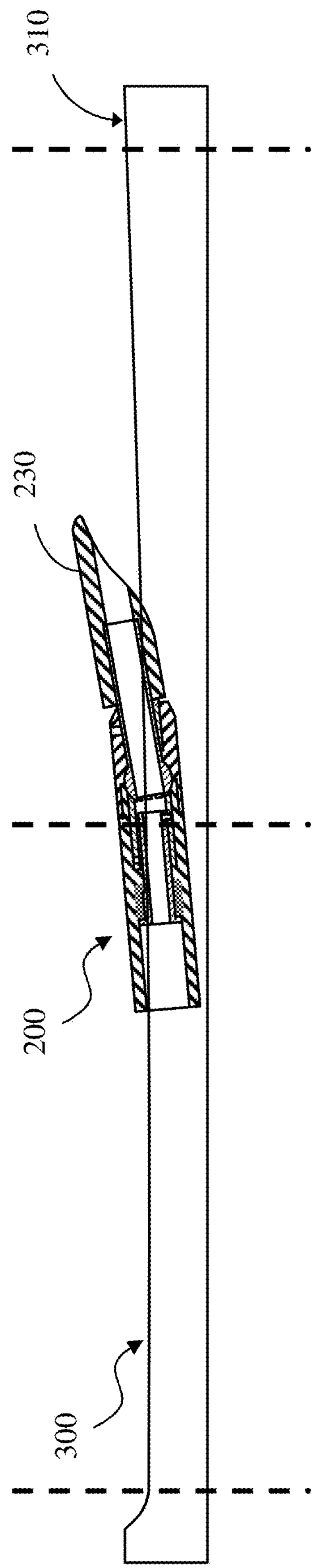
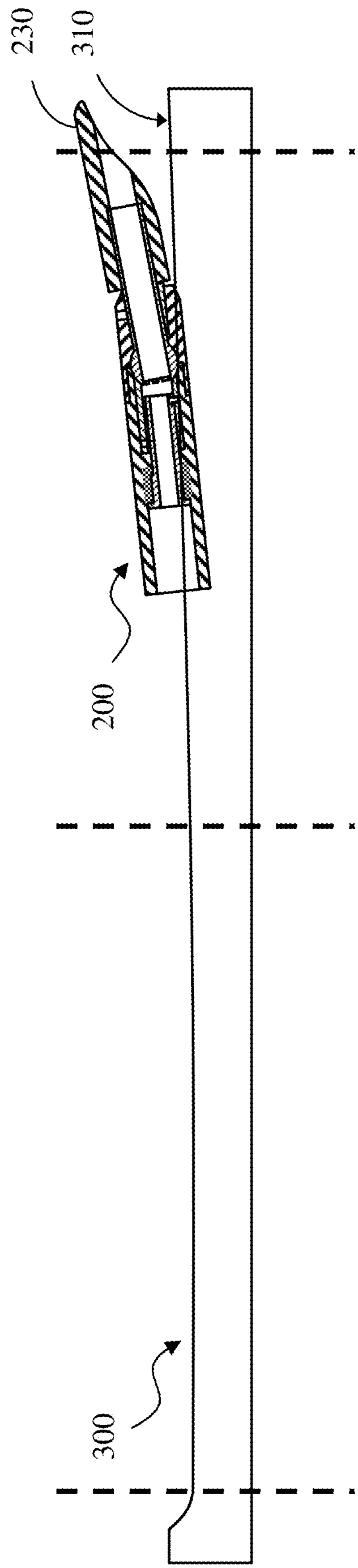


FIG. 3D



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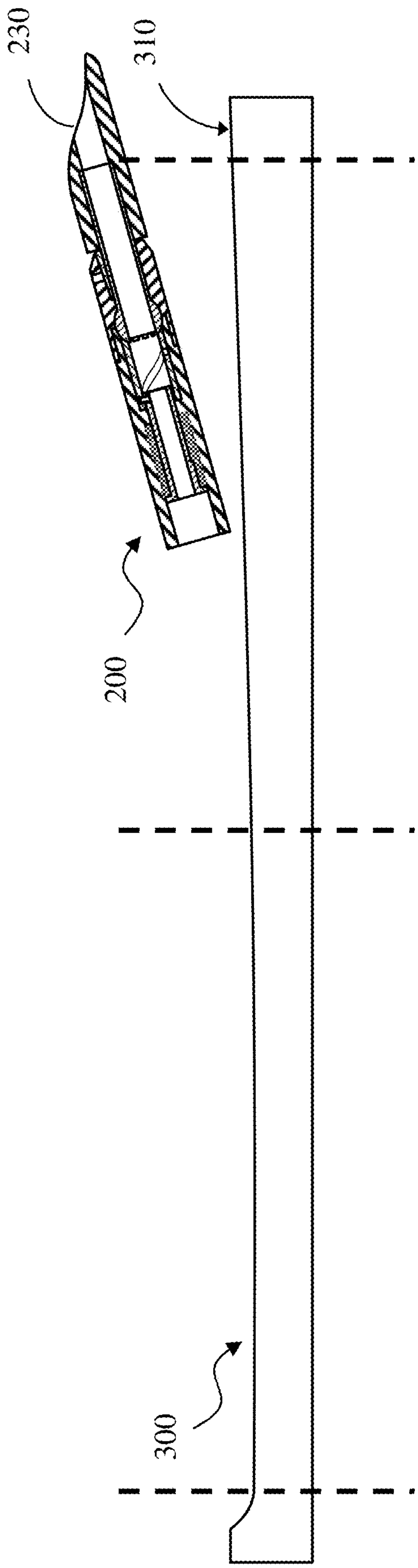

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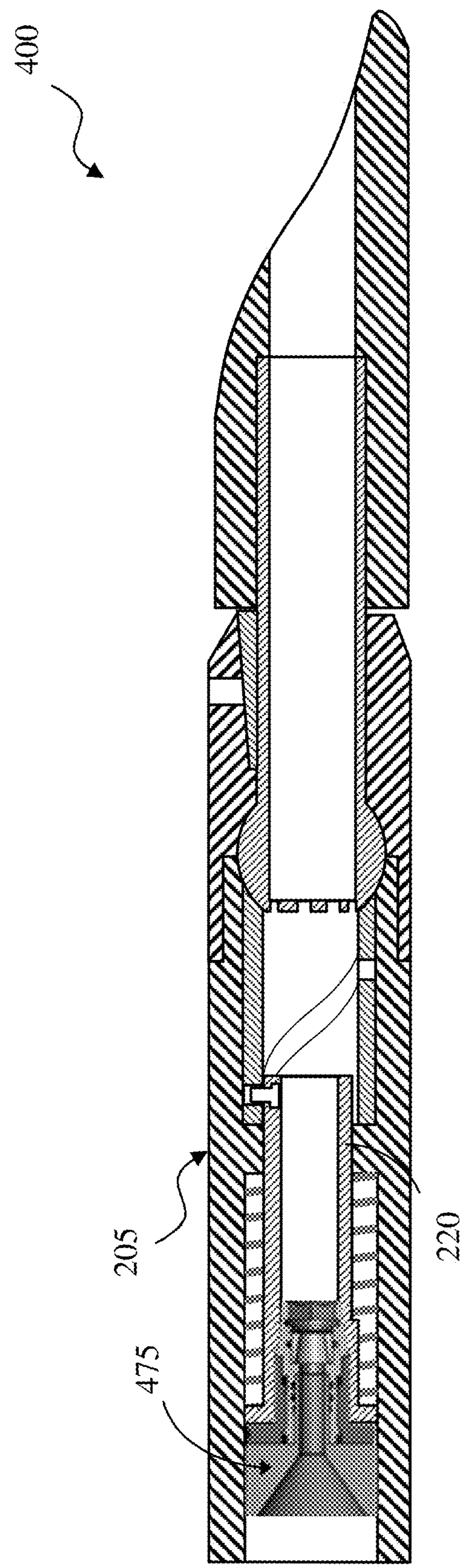

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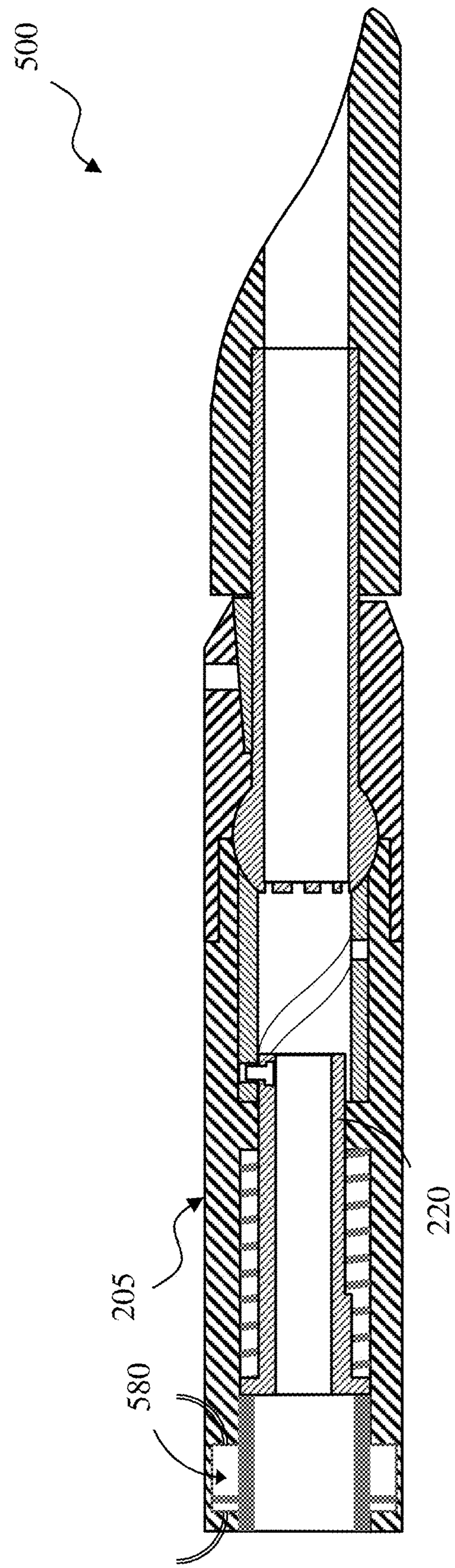

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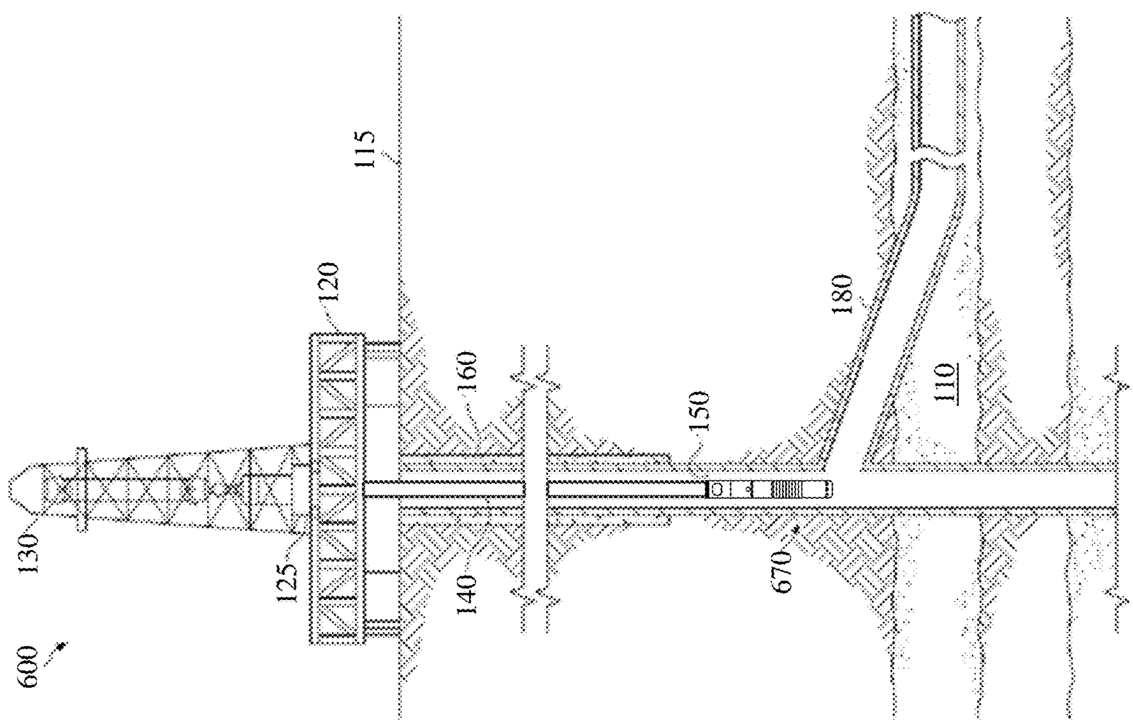

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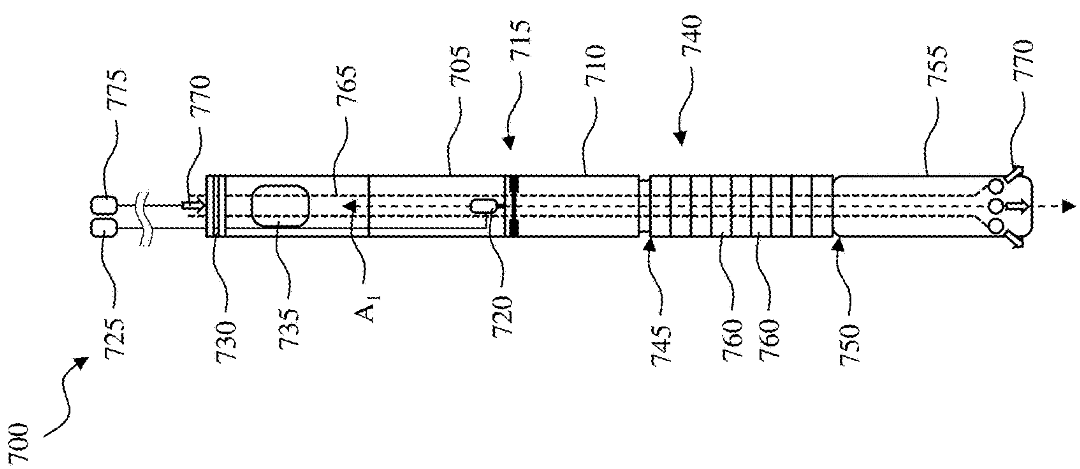
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FIG. 7A

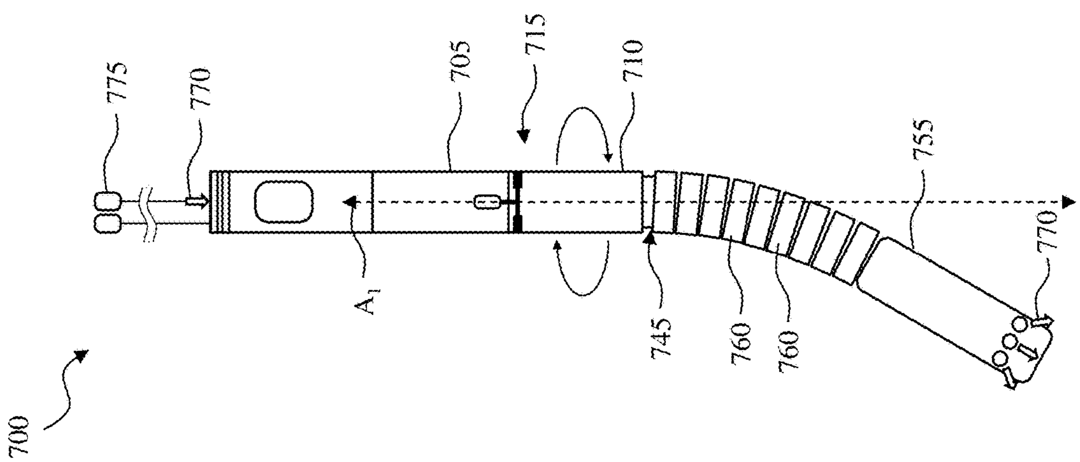


FIG. 7B

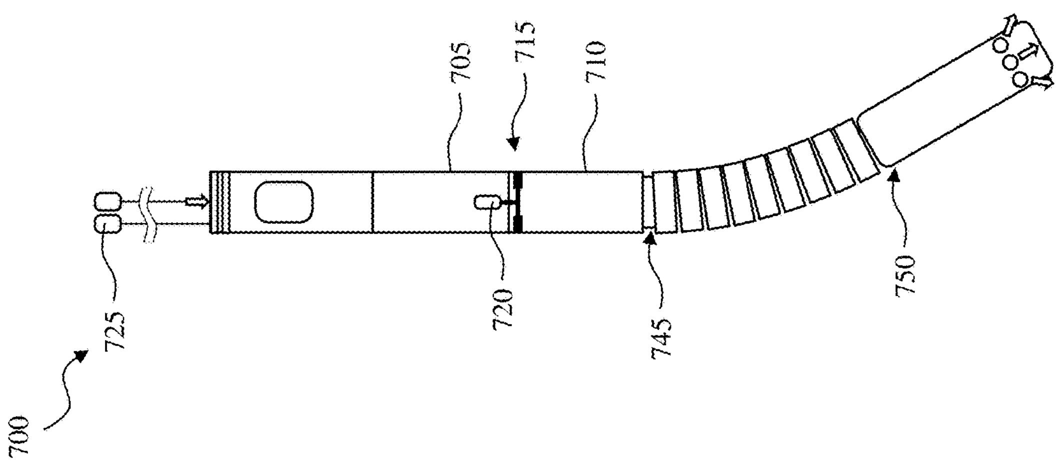


FIG. 7C

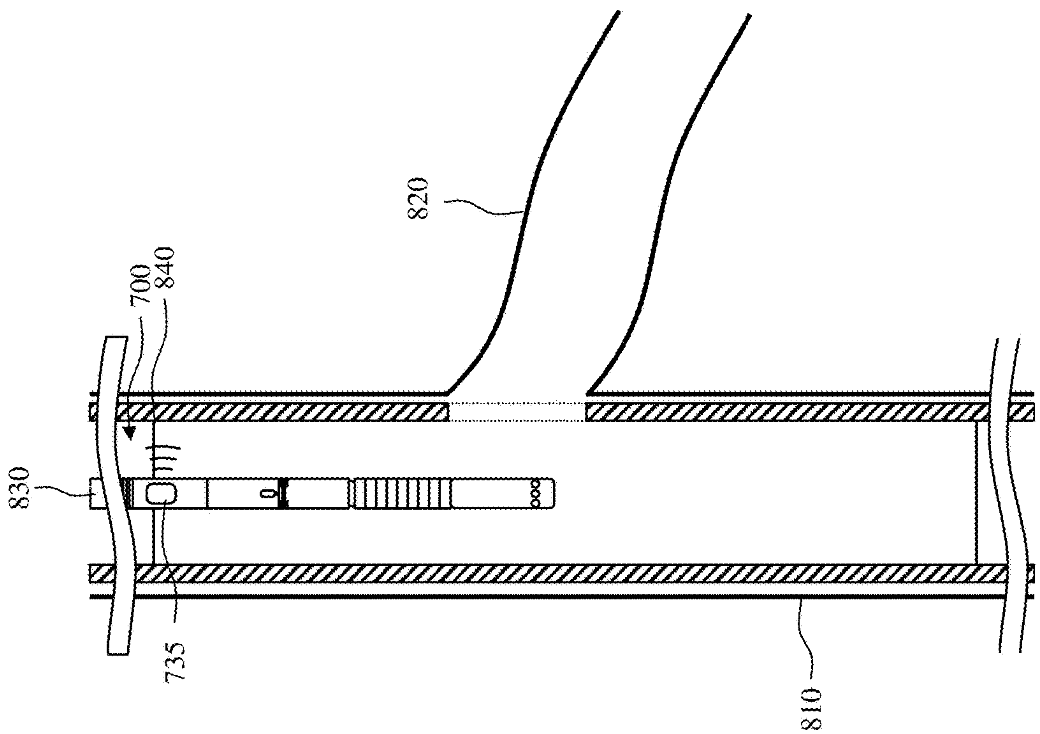
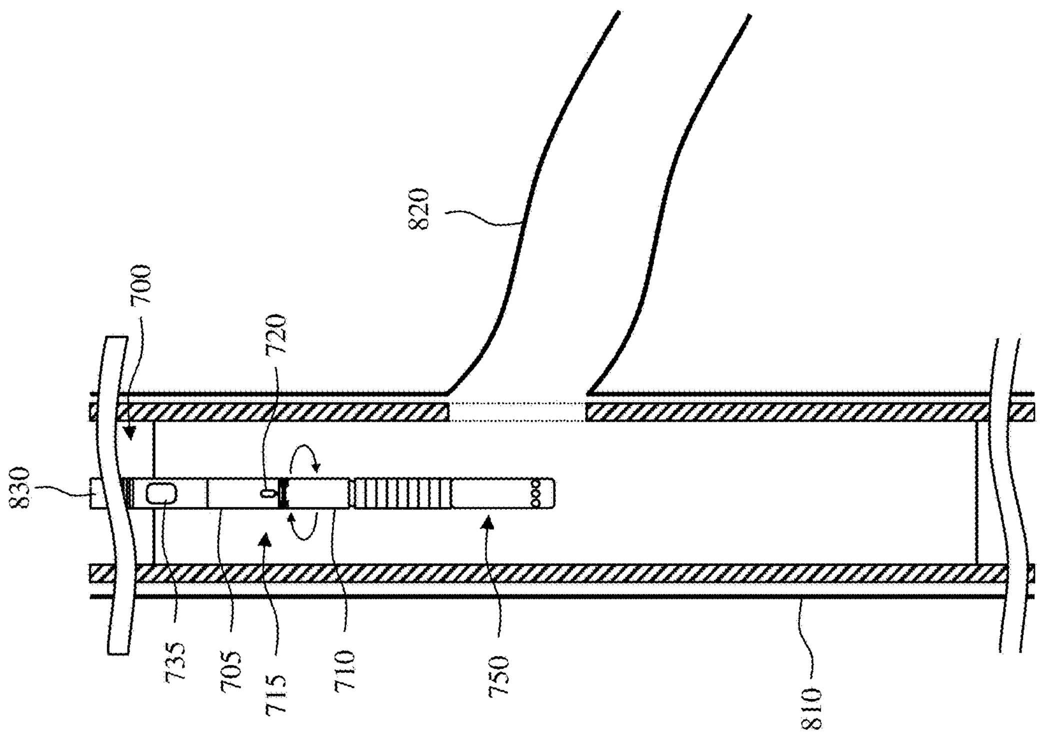


FIG. 8A



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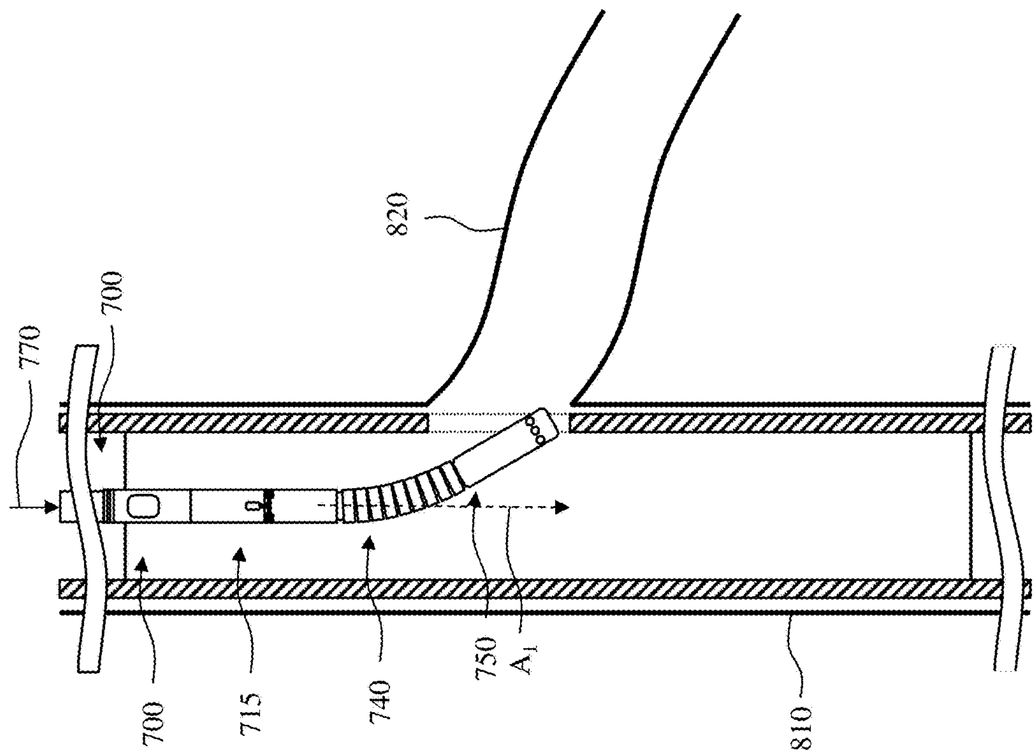


FIG. 8C

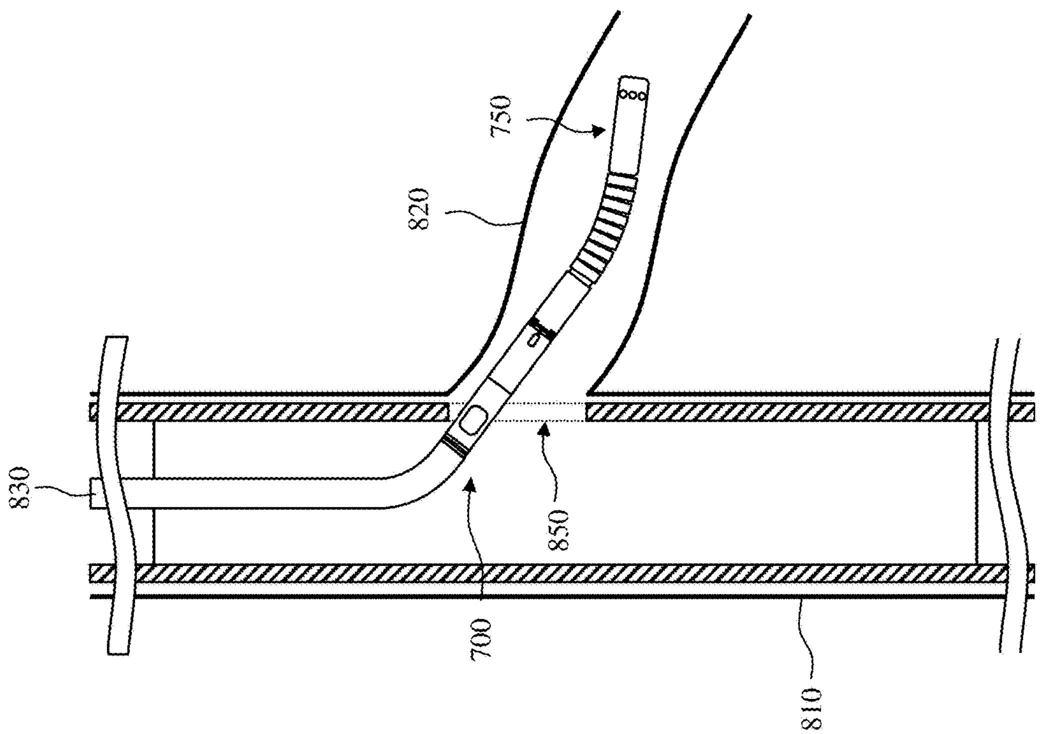


FIG. 8D

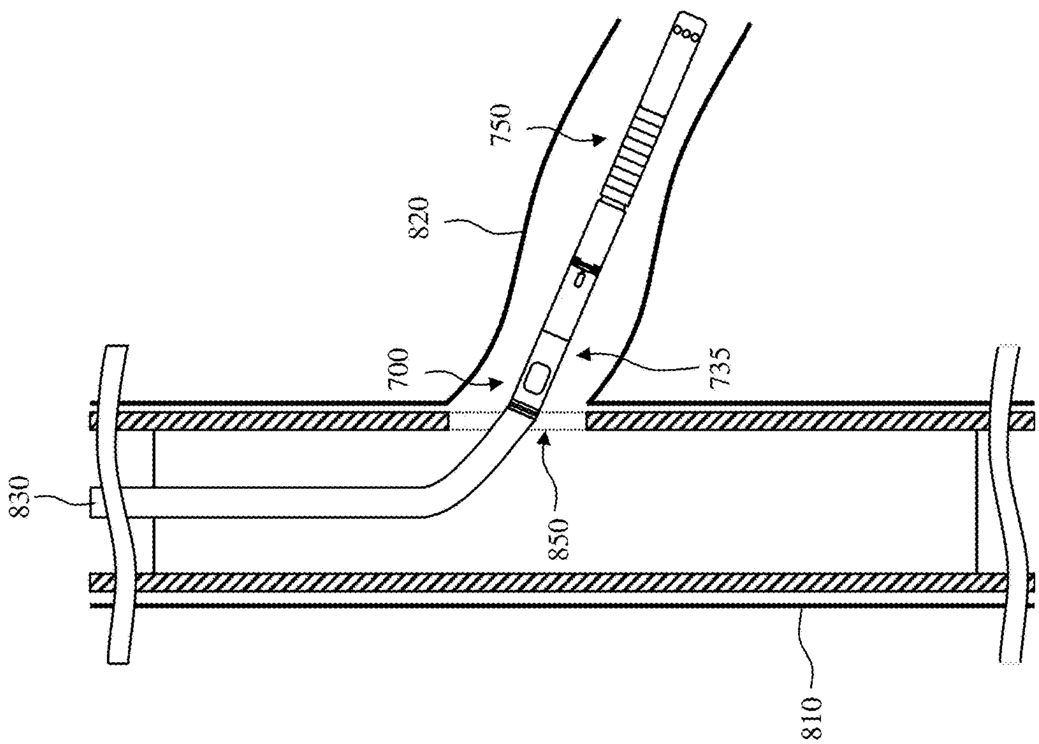
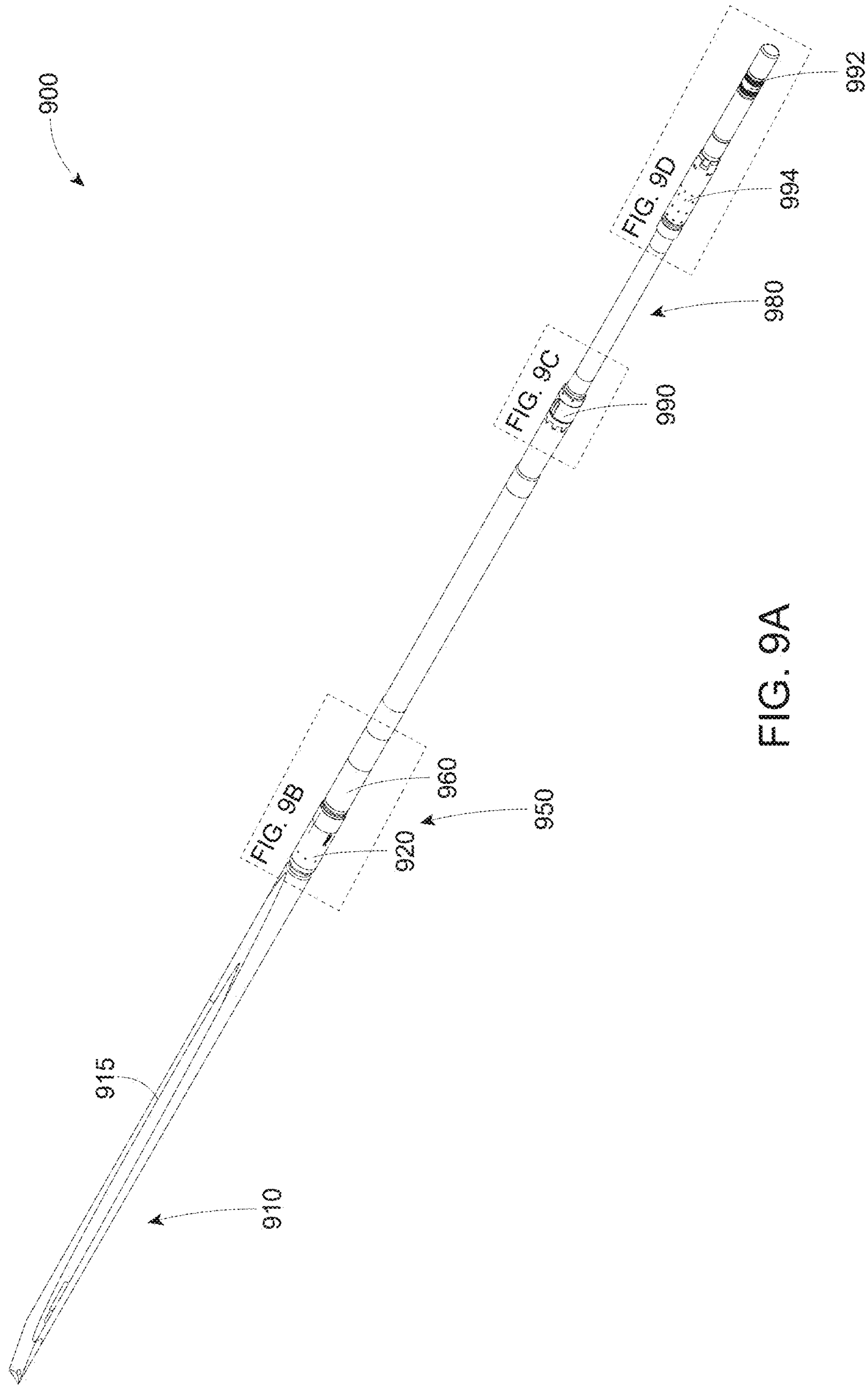


FIG. 8E



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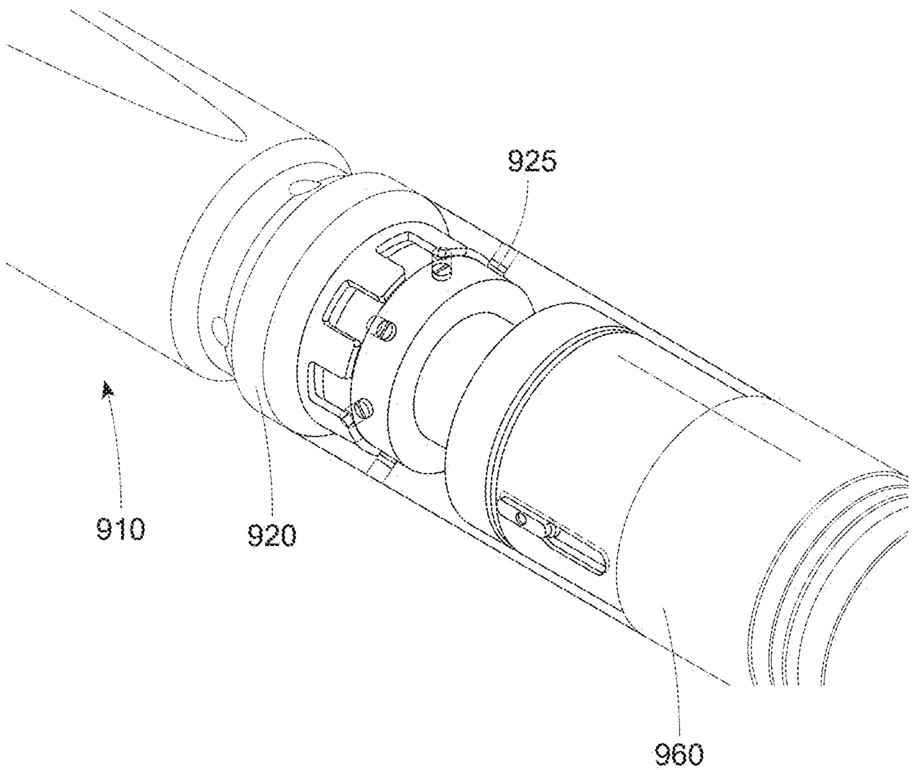

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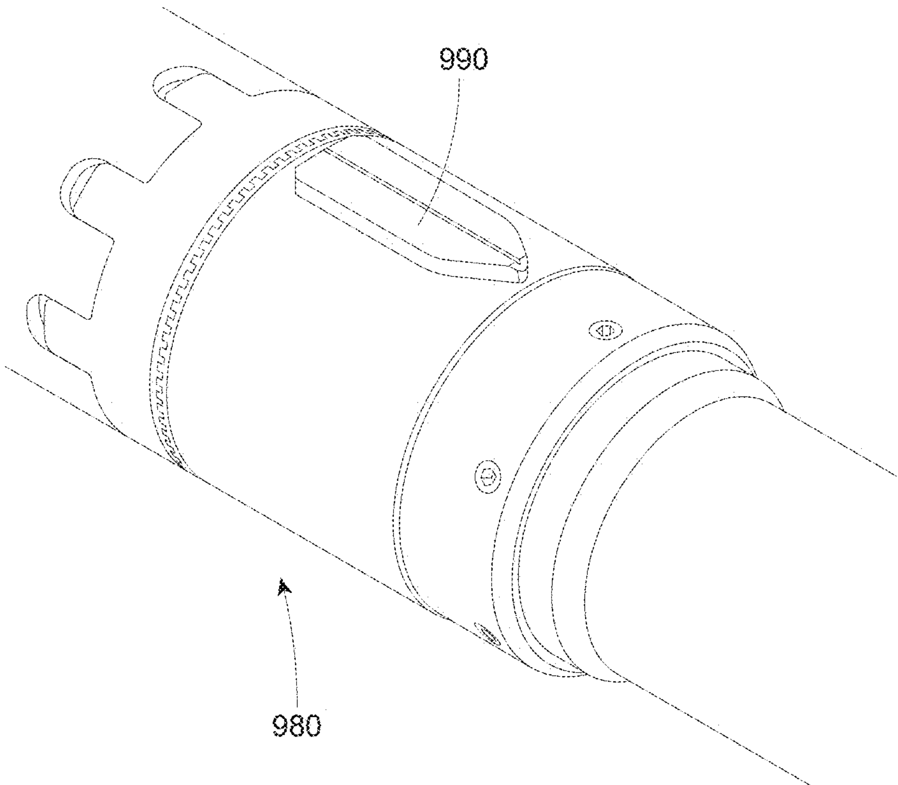

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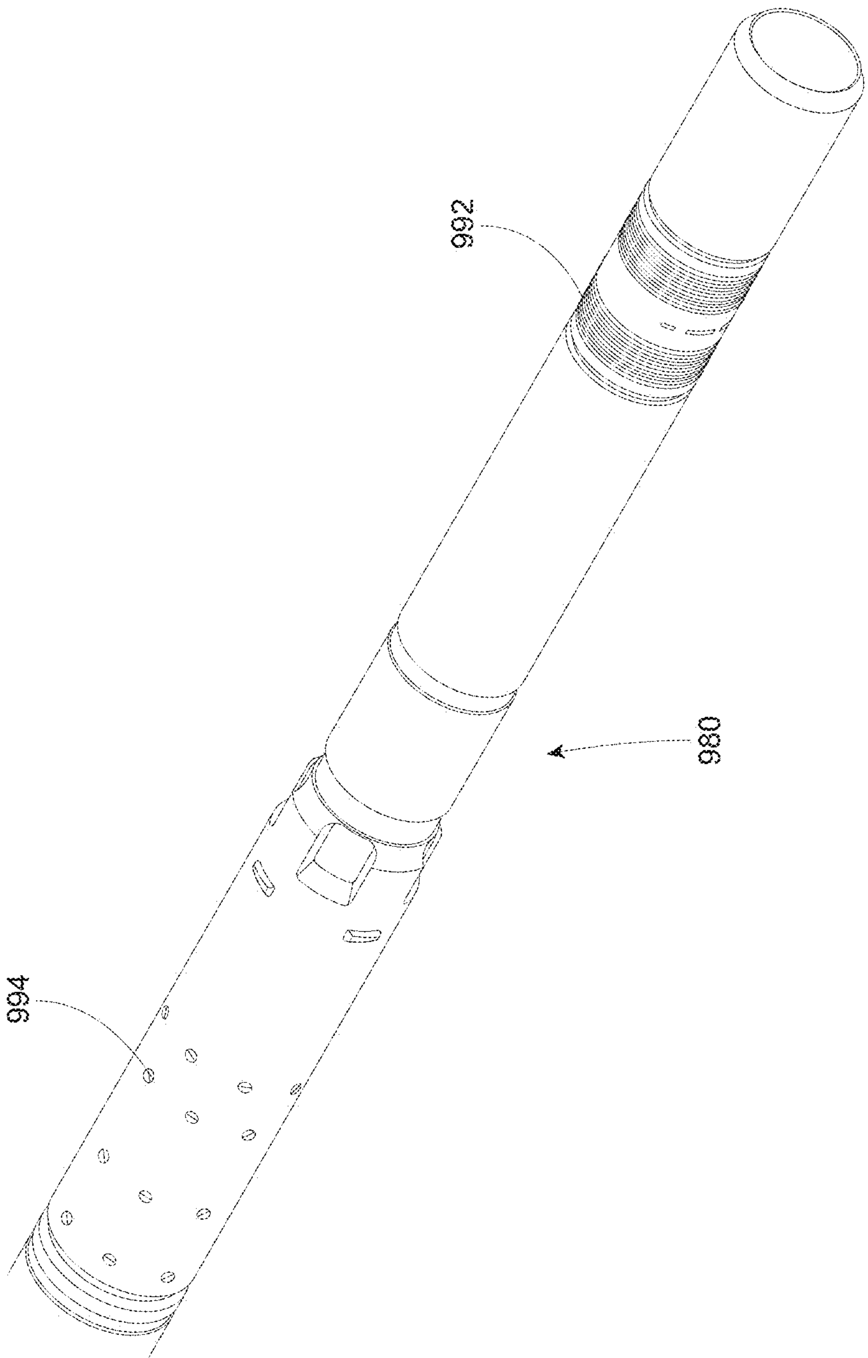

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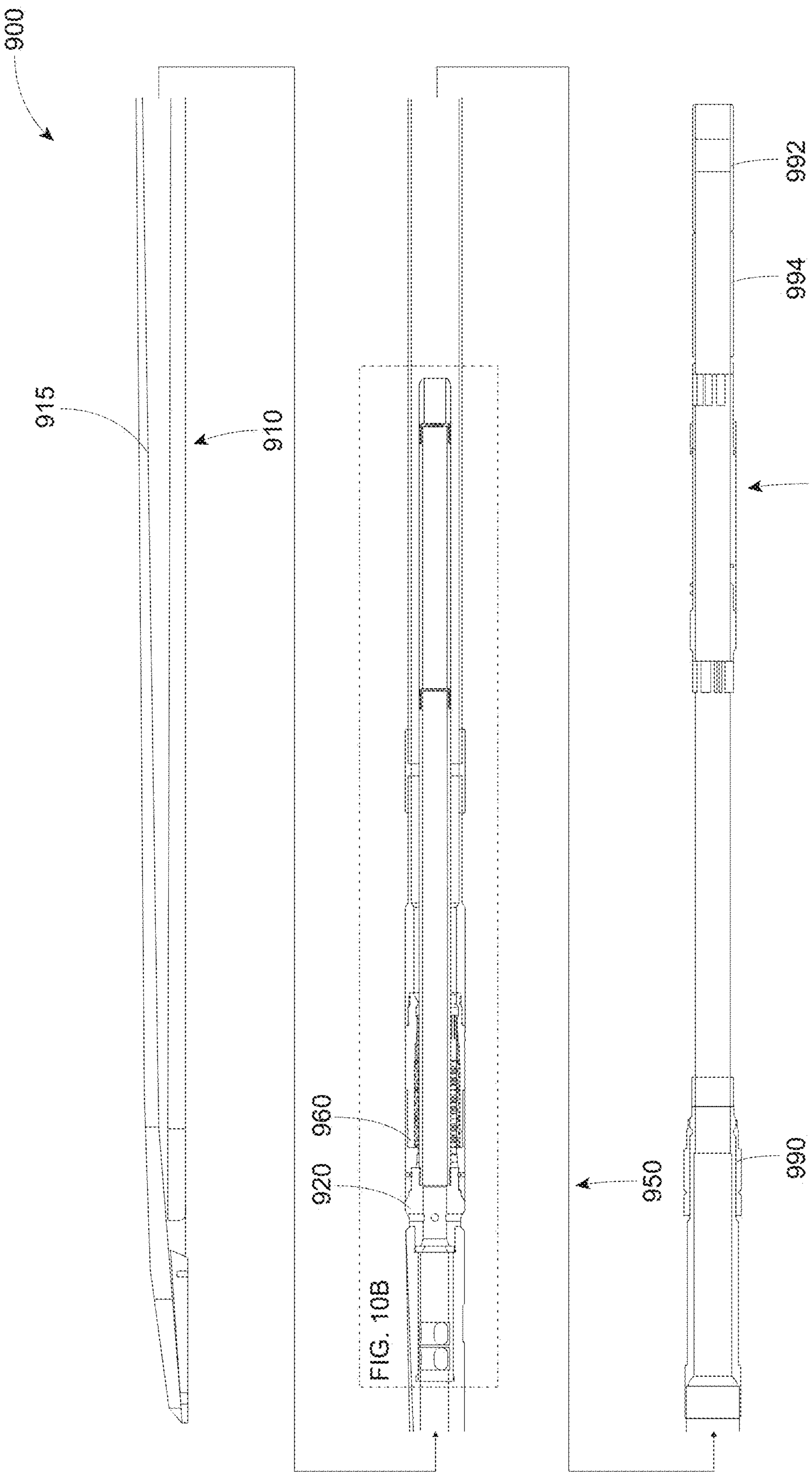


FIG. 10A

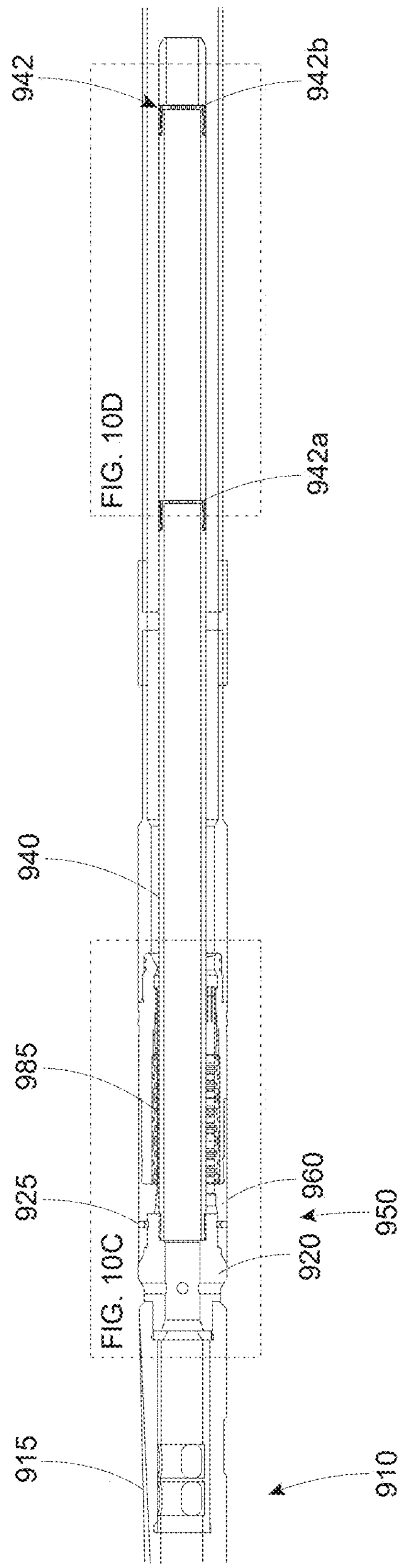
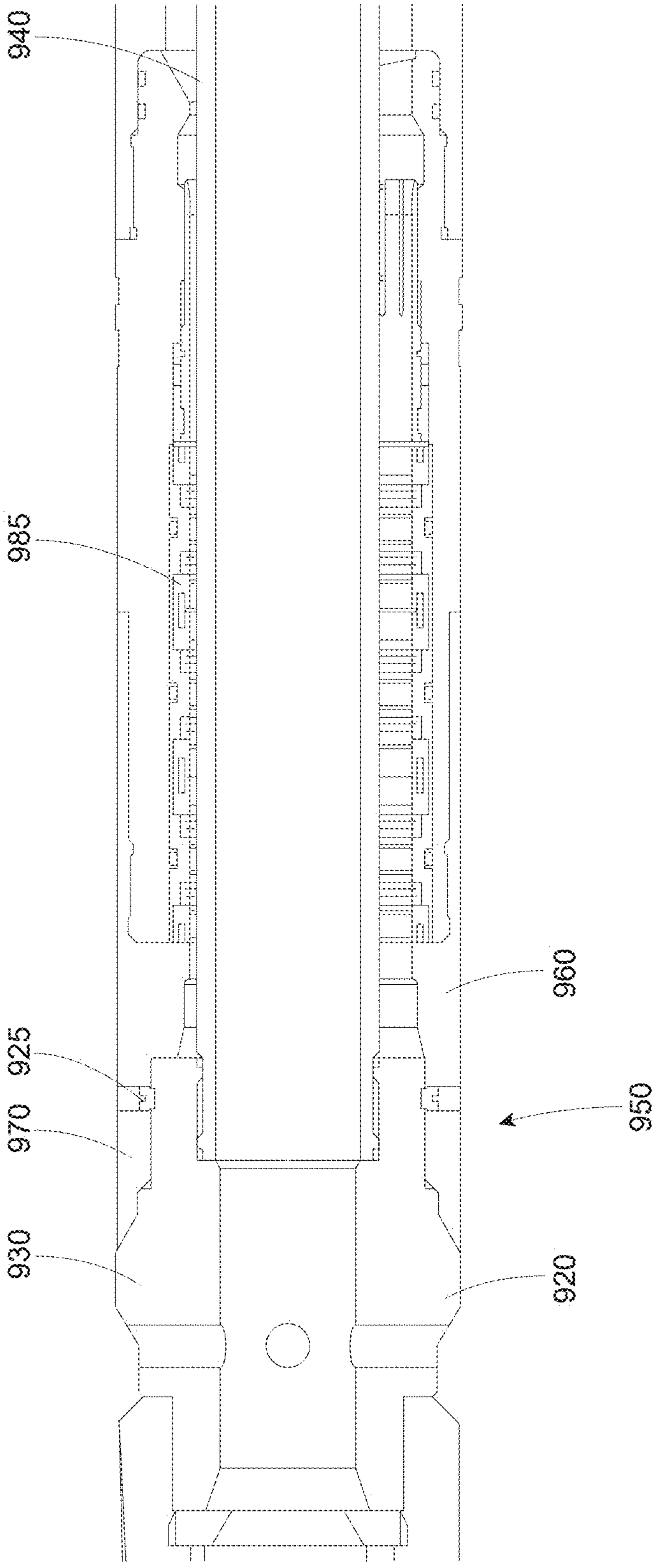


FIG. 10B



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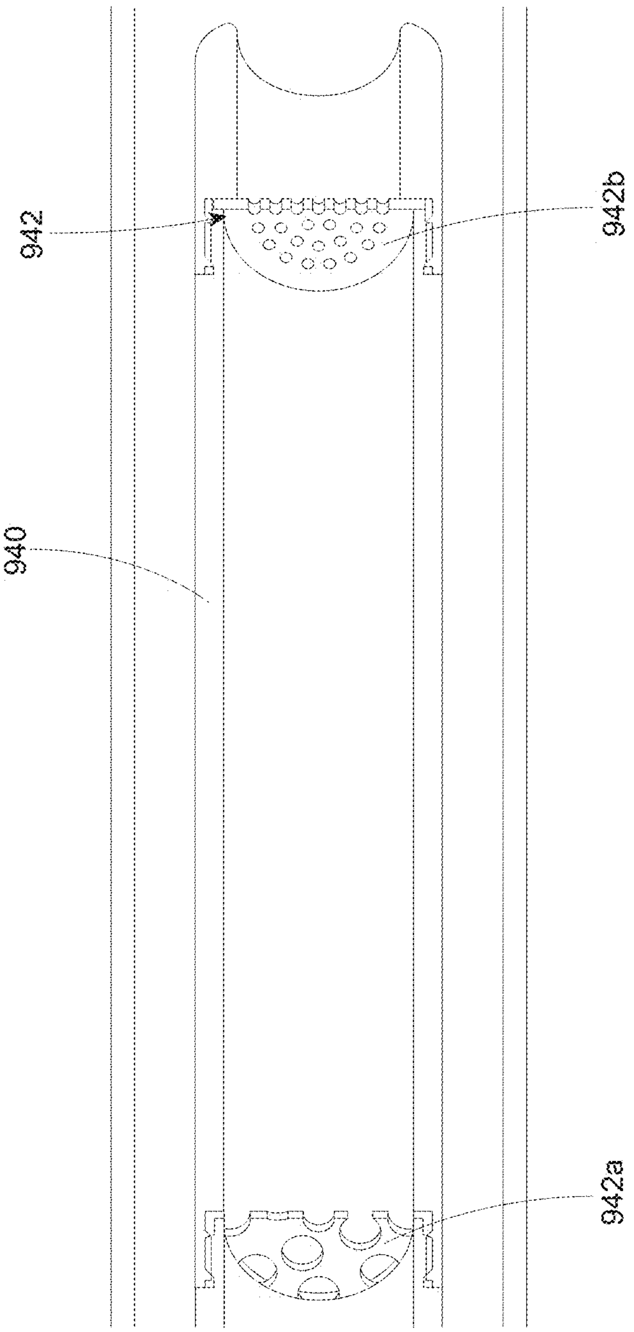


FIG. 10D

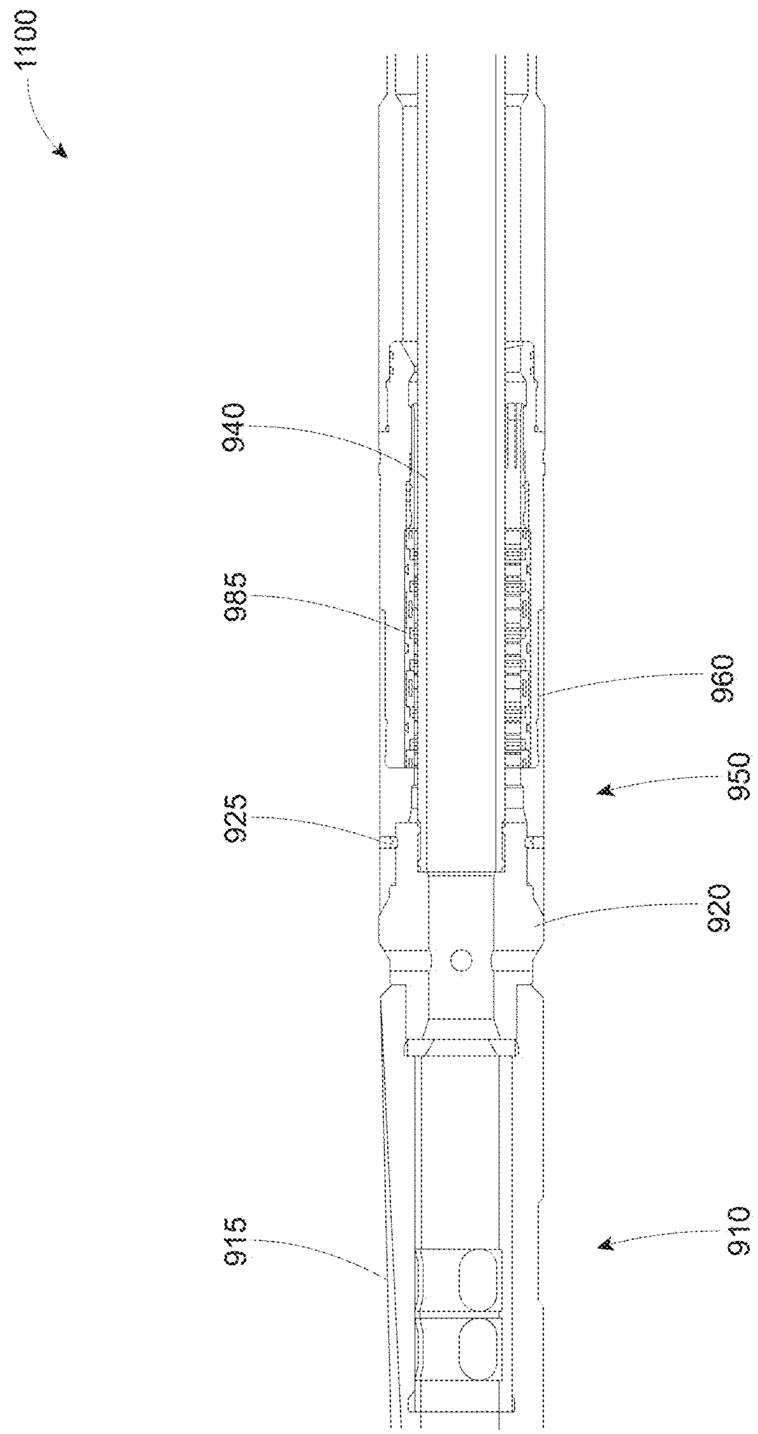


FIG. 11A

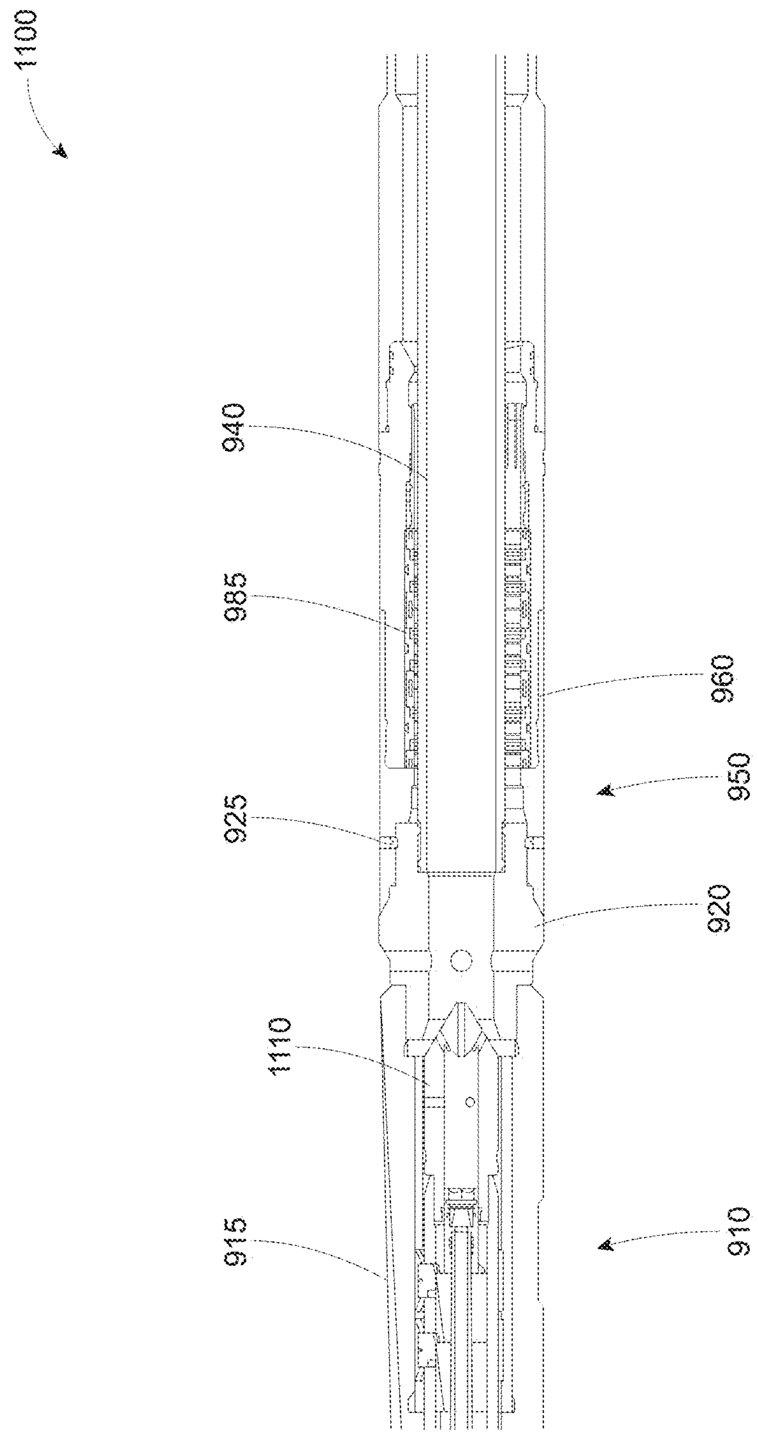


FIG. 11B

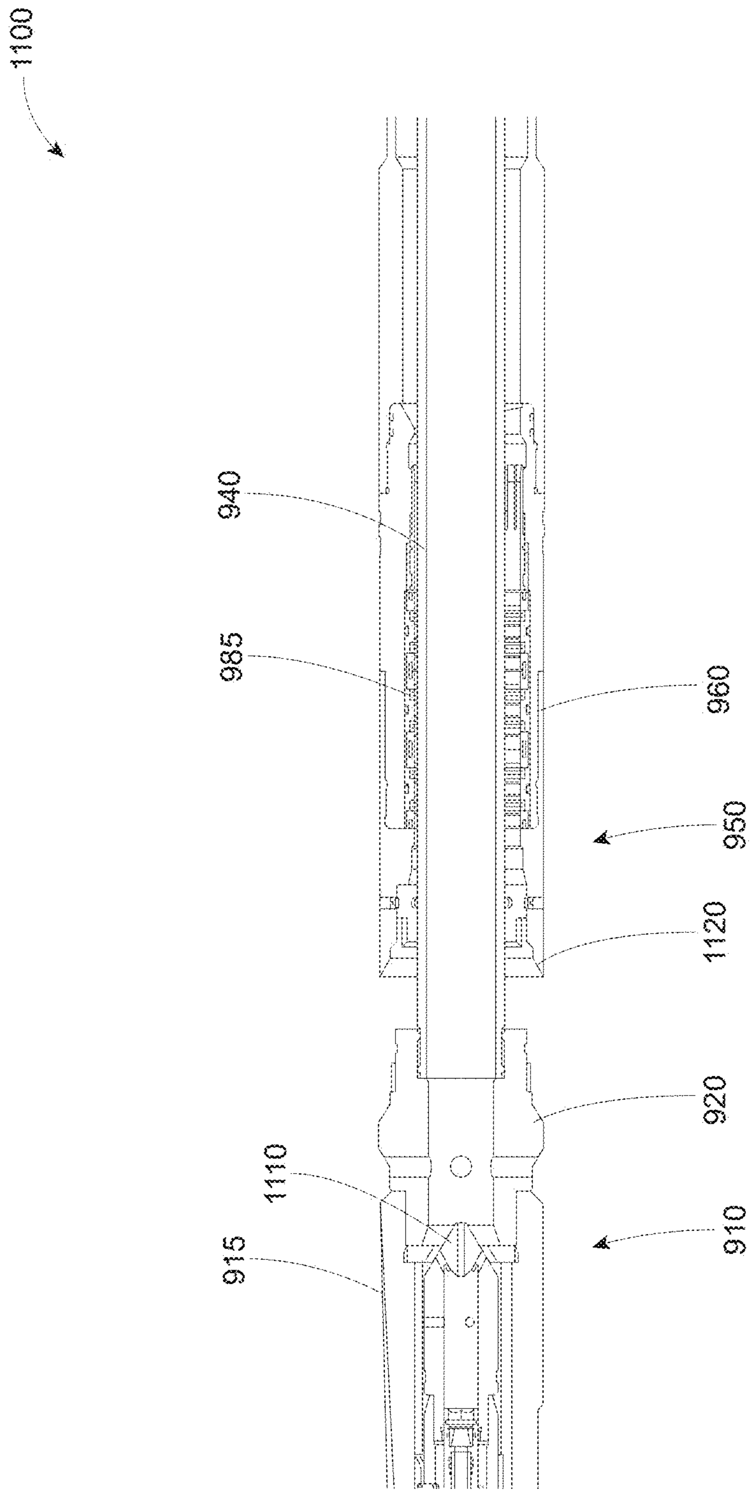
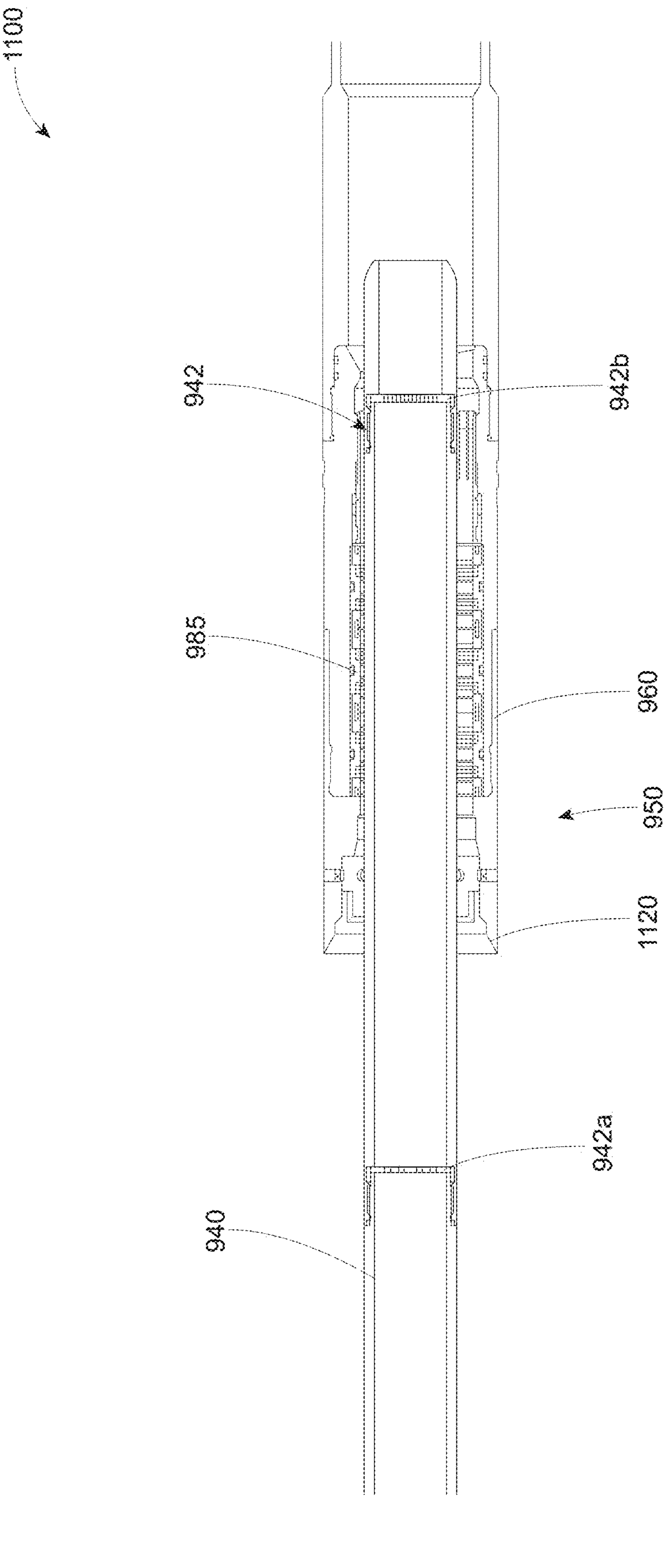


FIG. 11C



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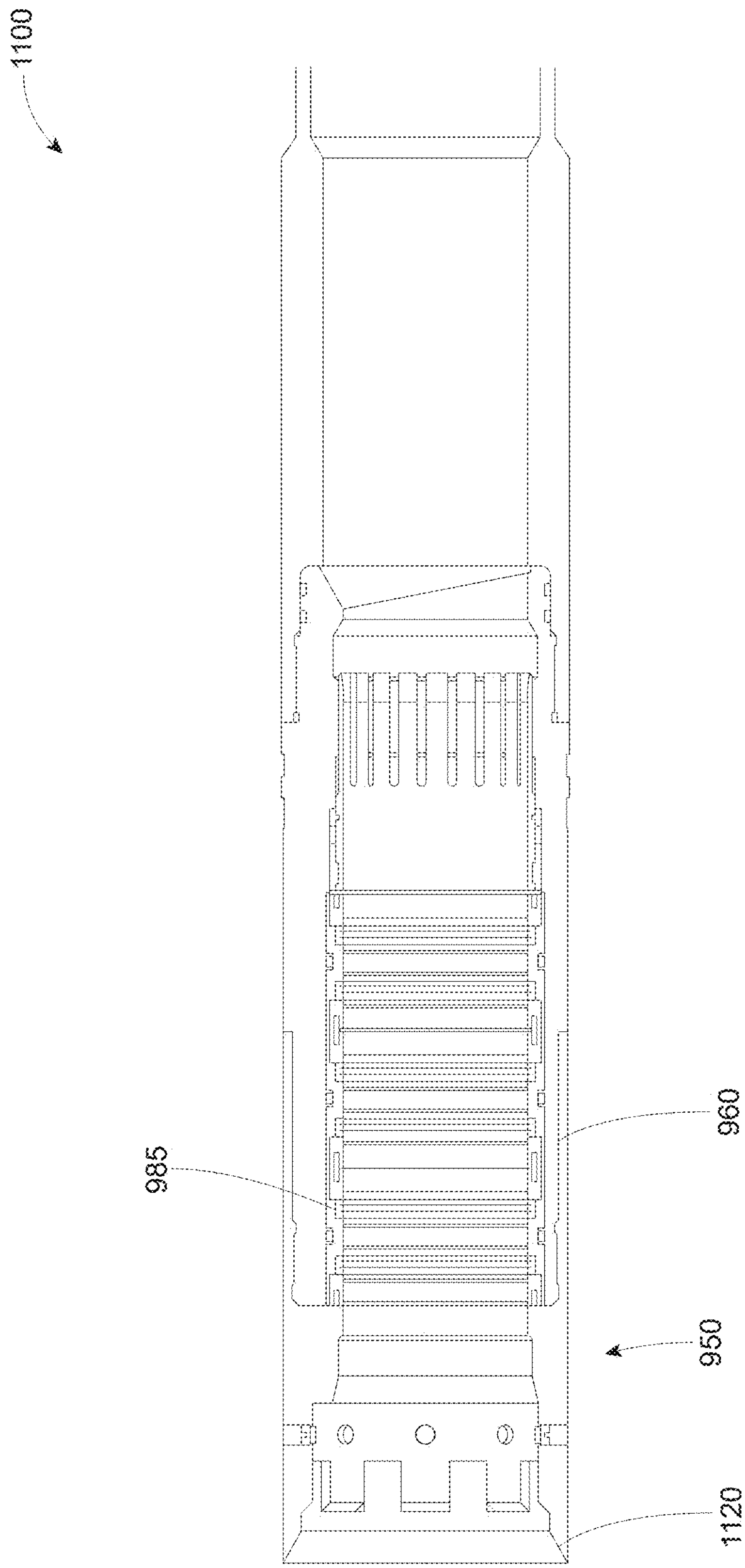


FIG. 11E

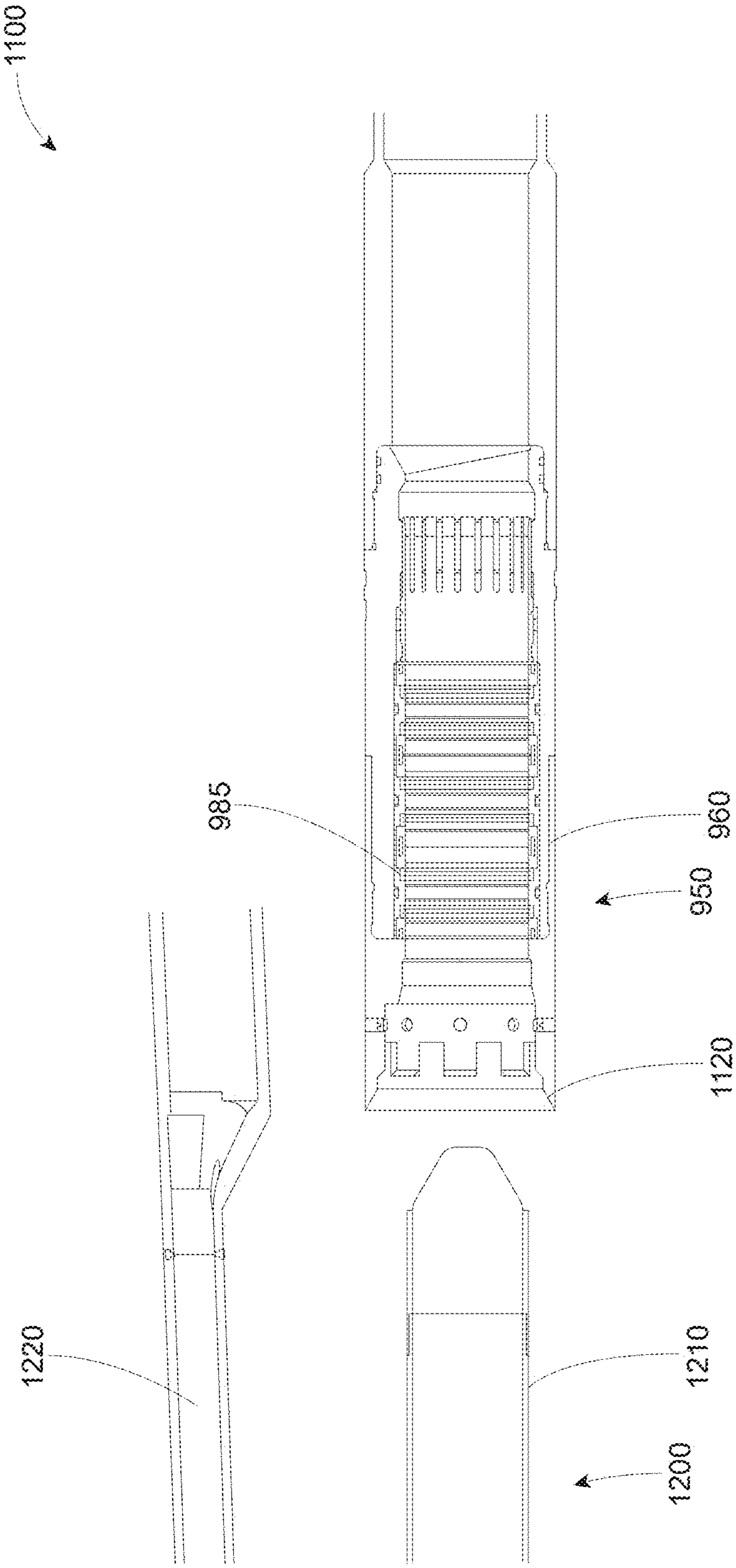


FIG. 12A

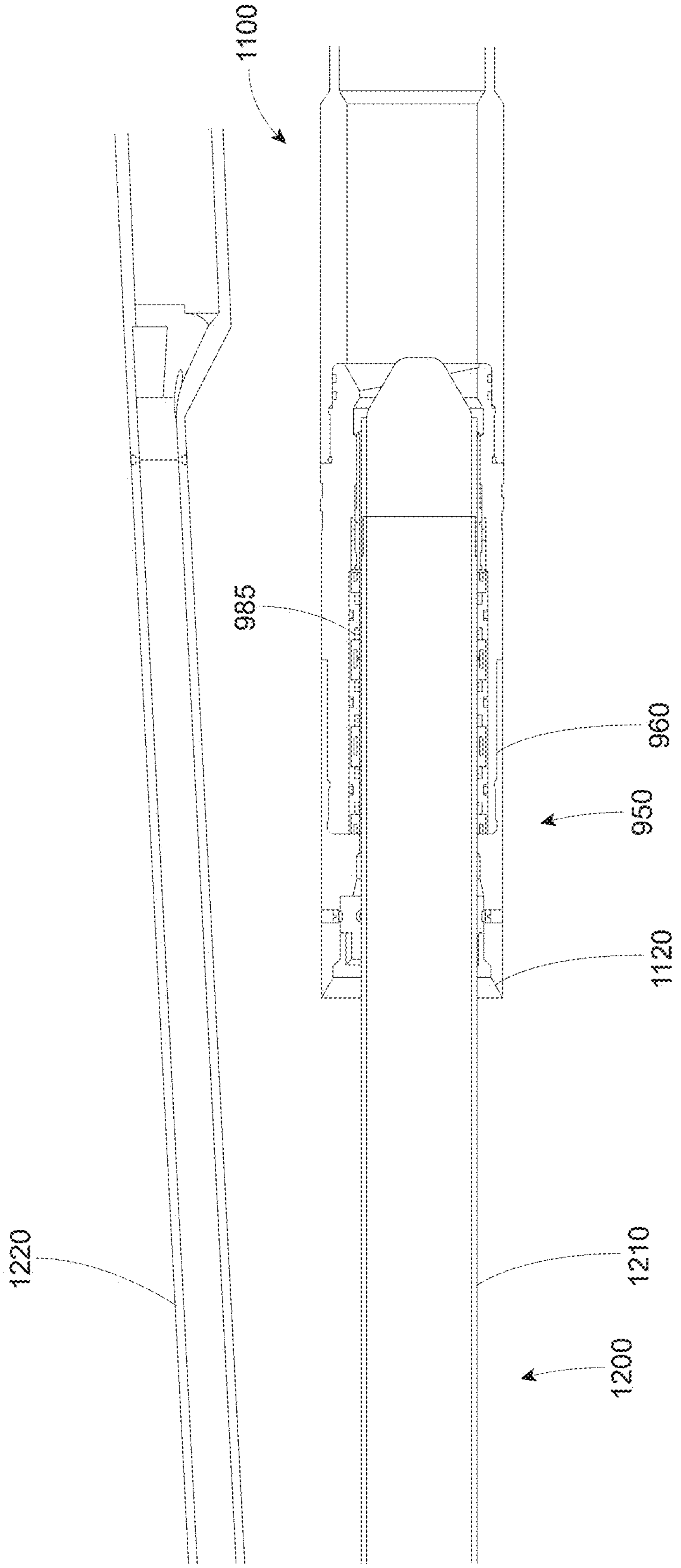
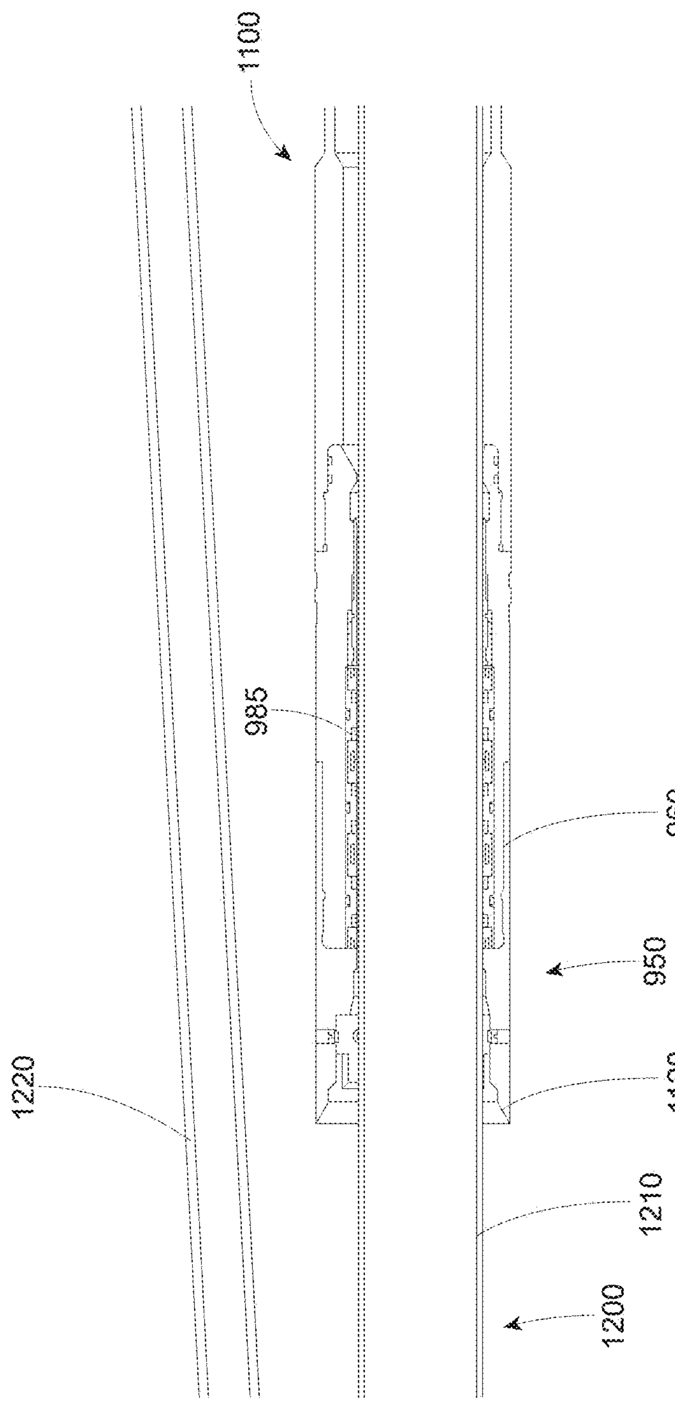


FIG. 12B



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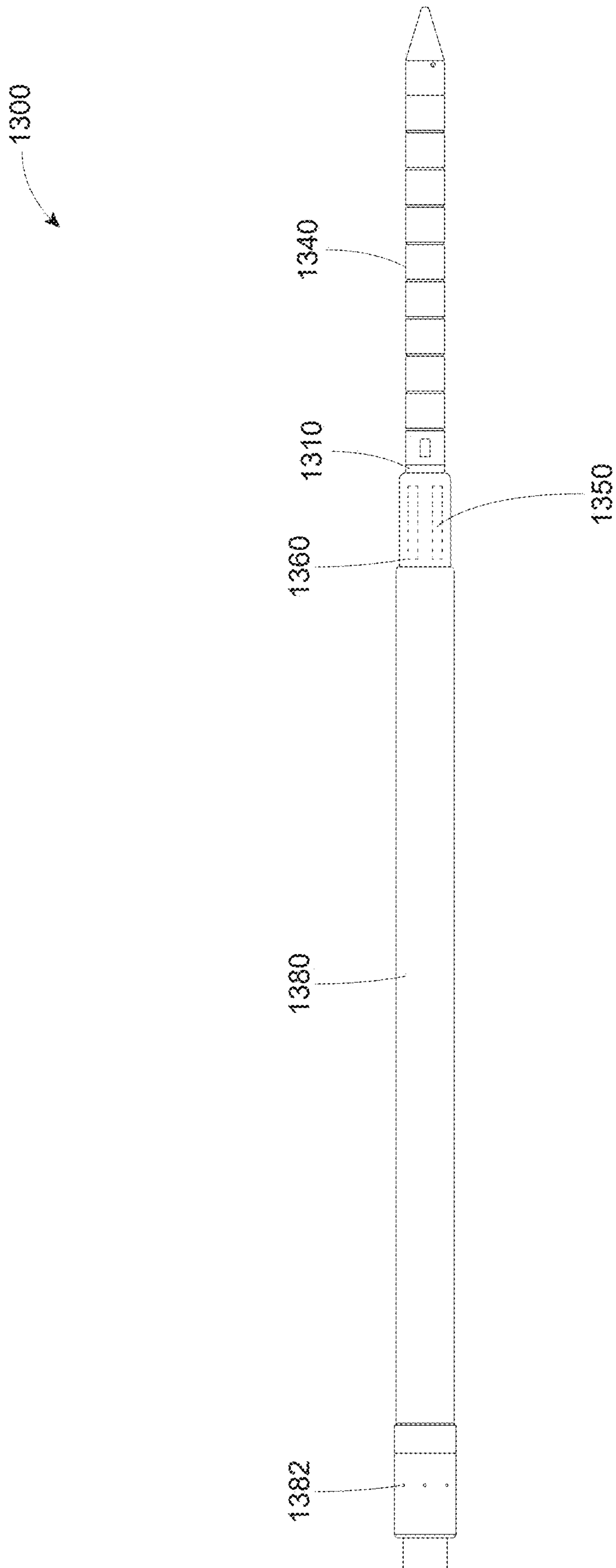
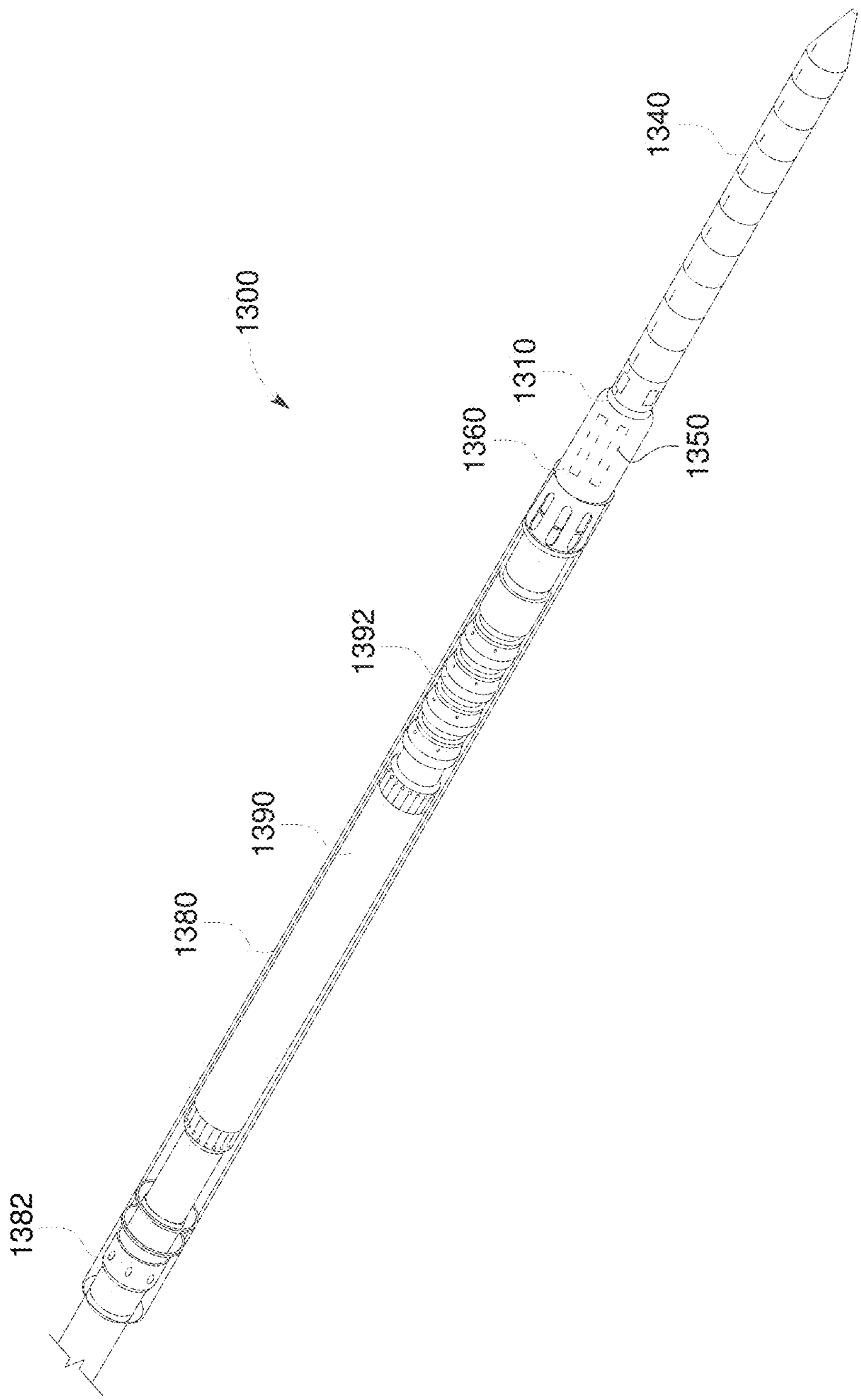


FIG. 13A



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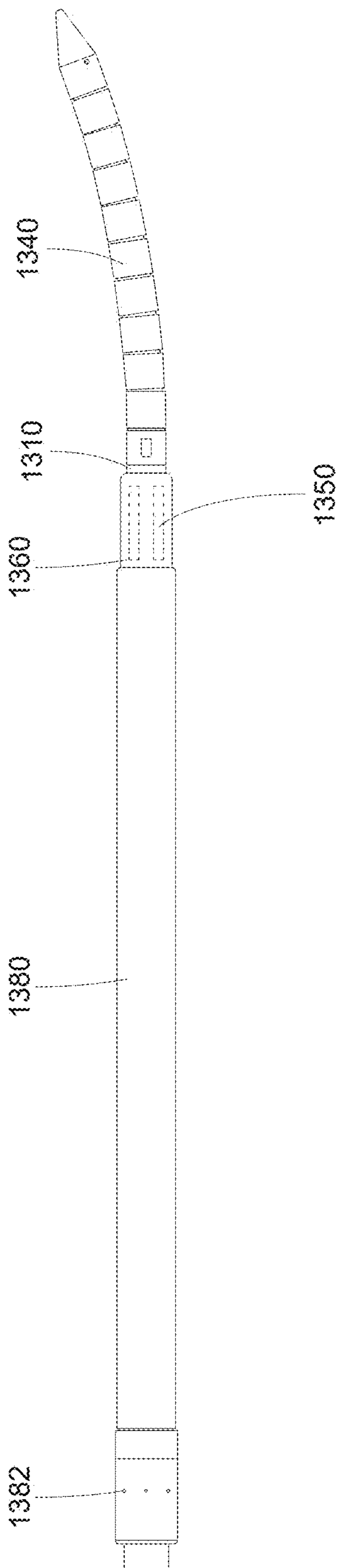

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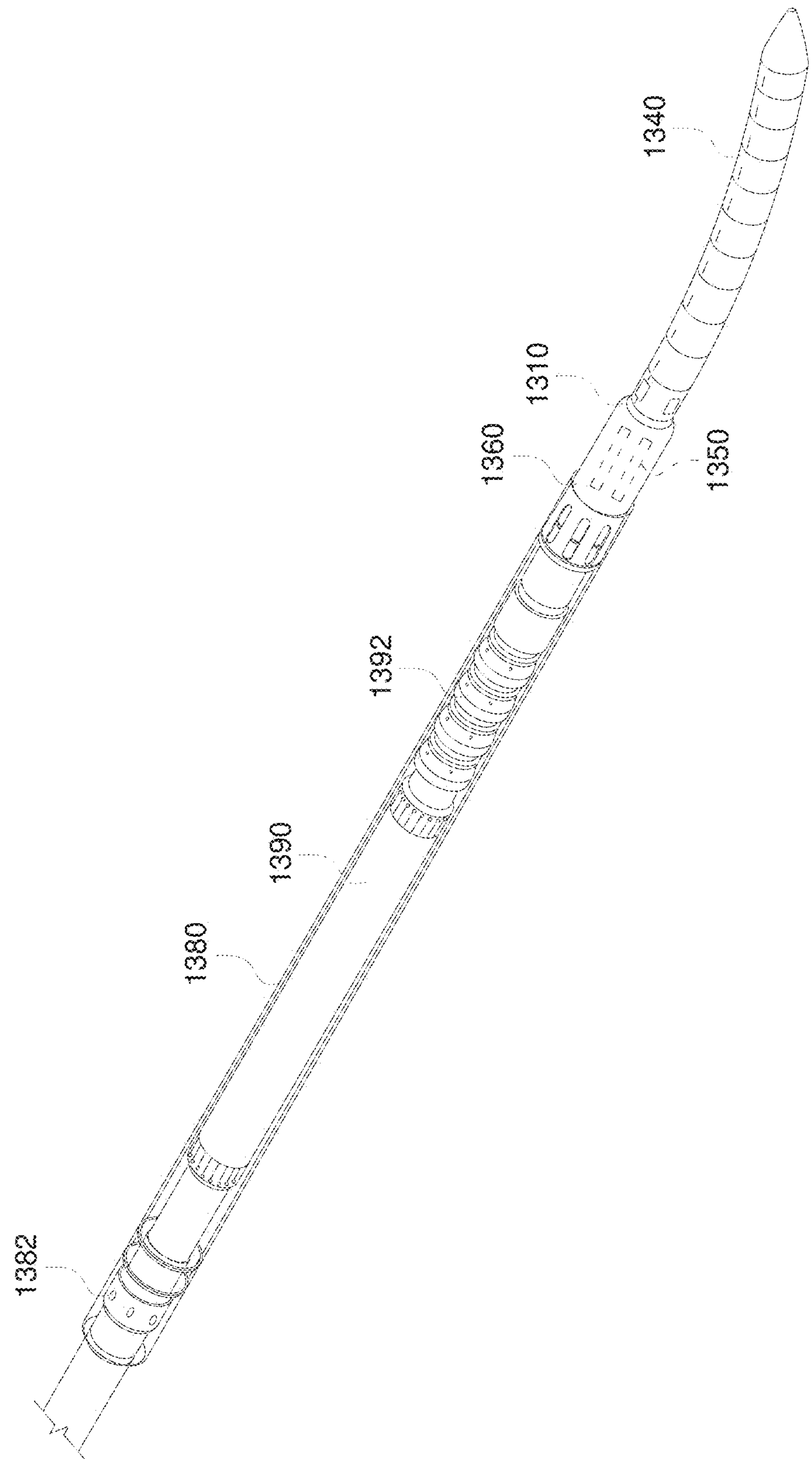
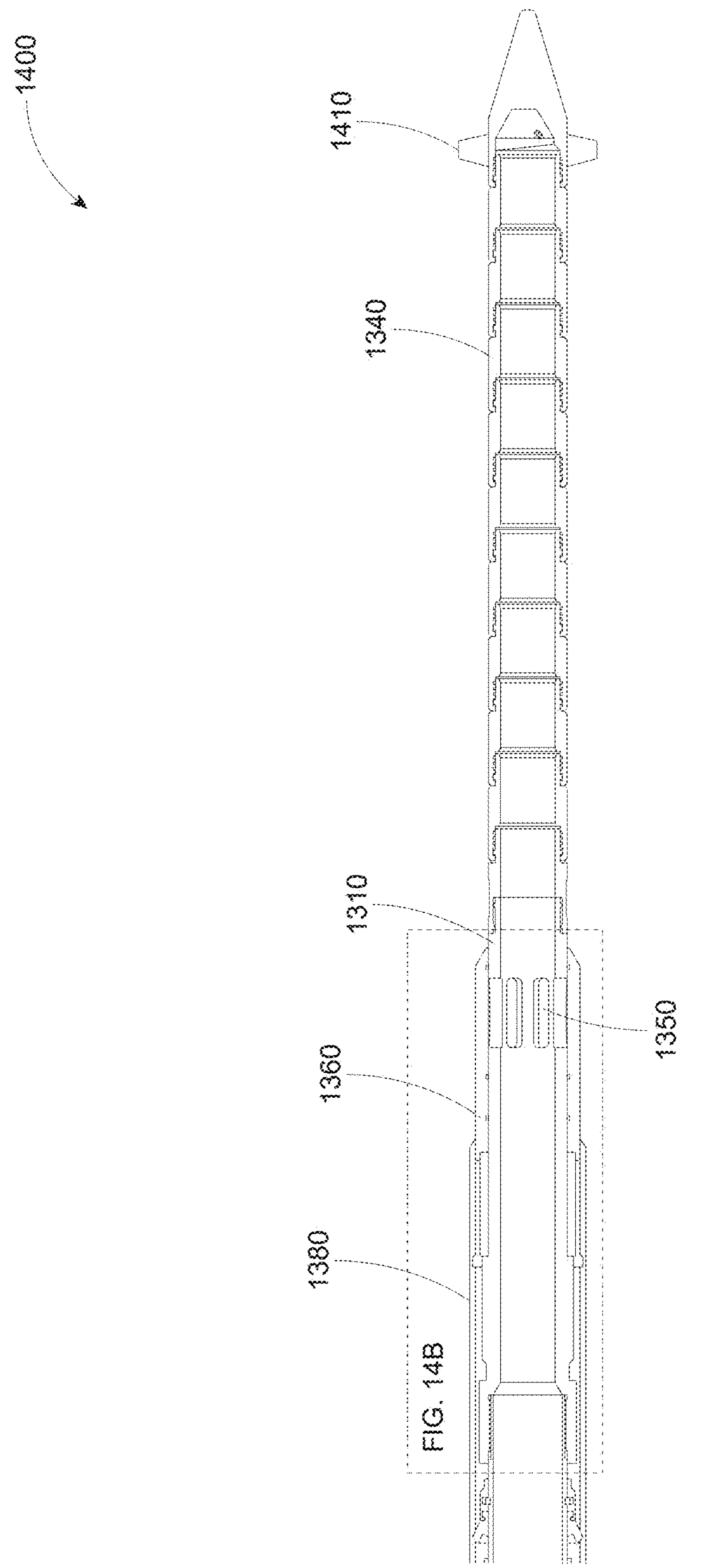


FIG. 13D



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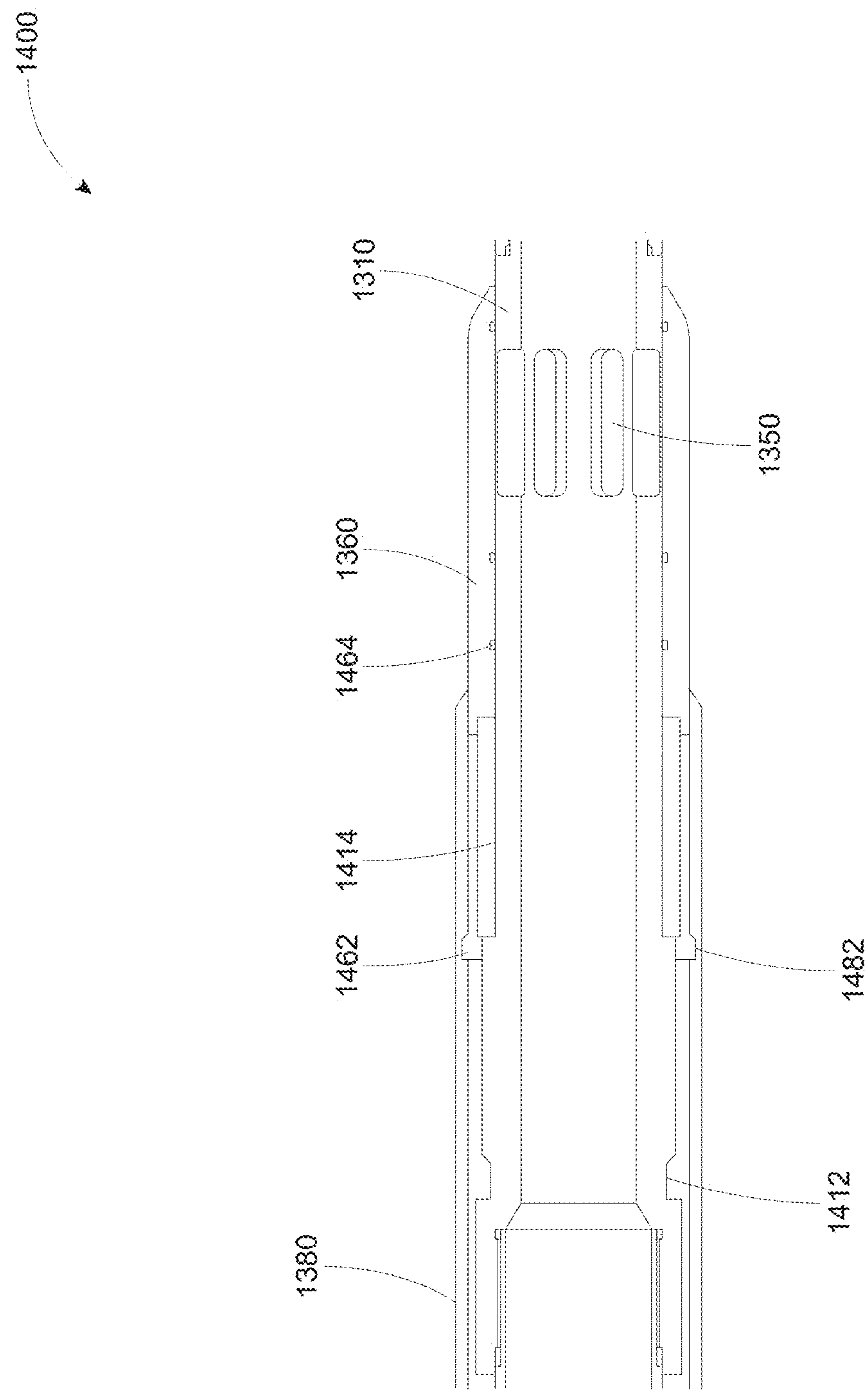

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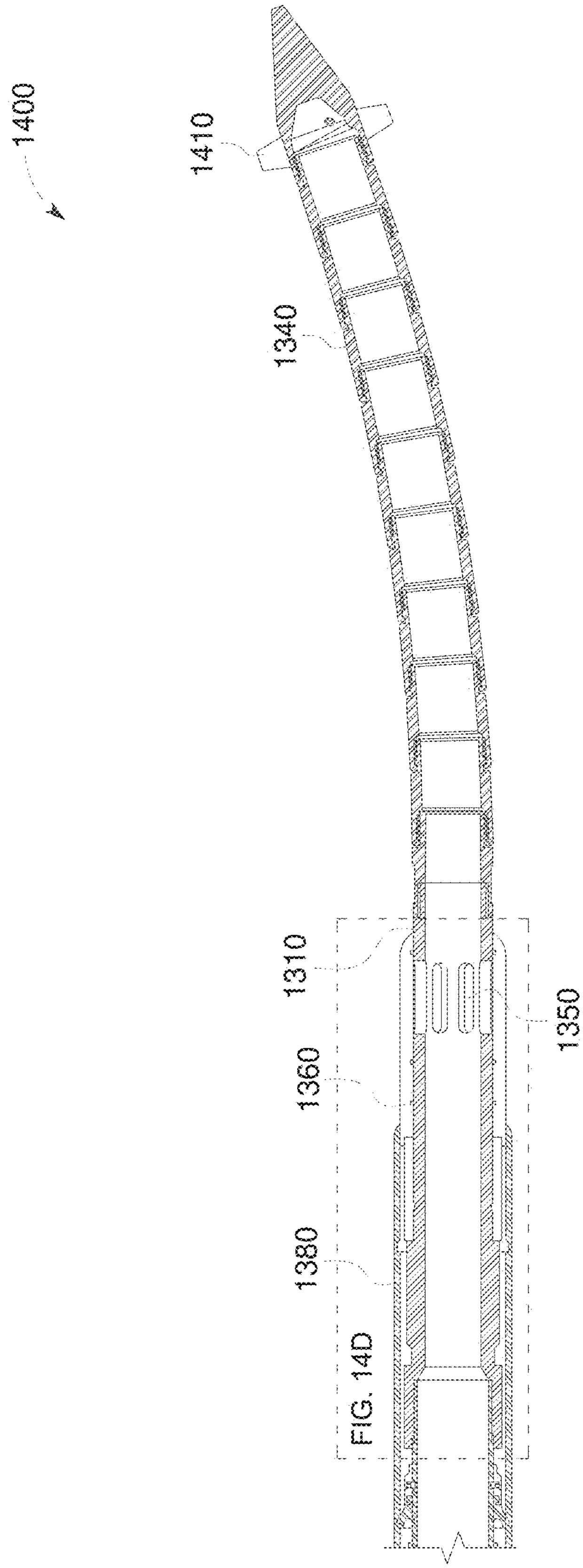

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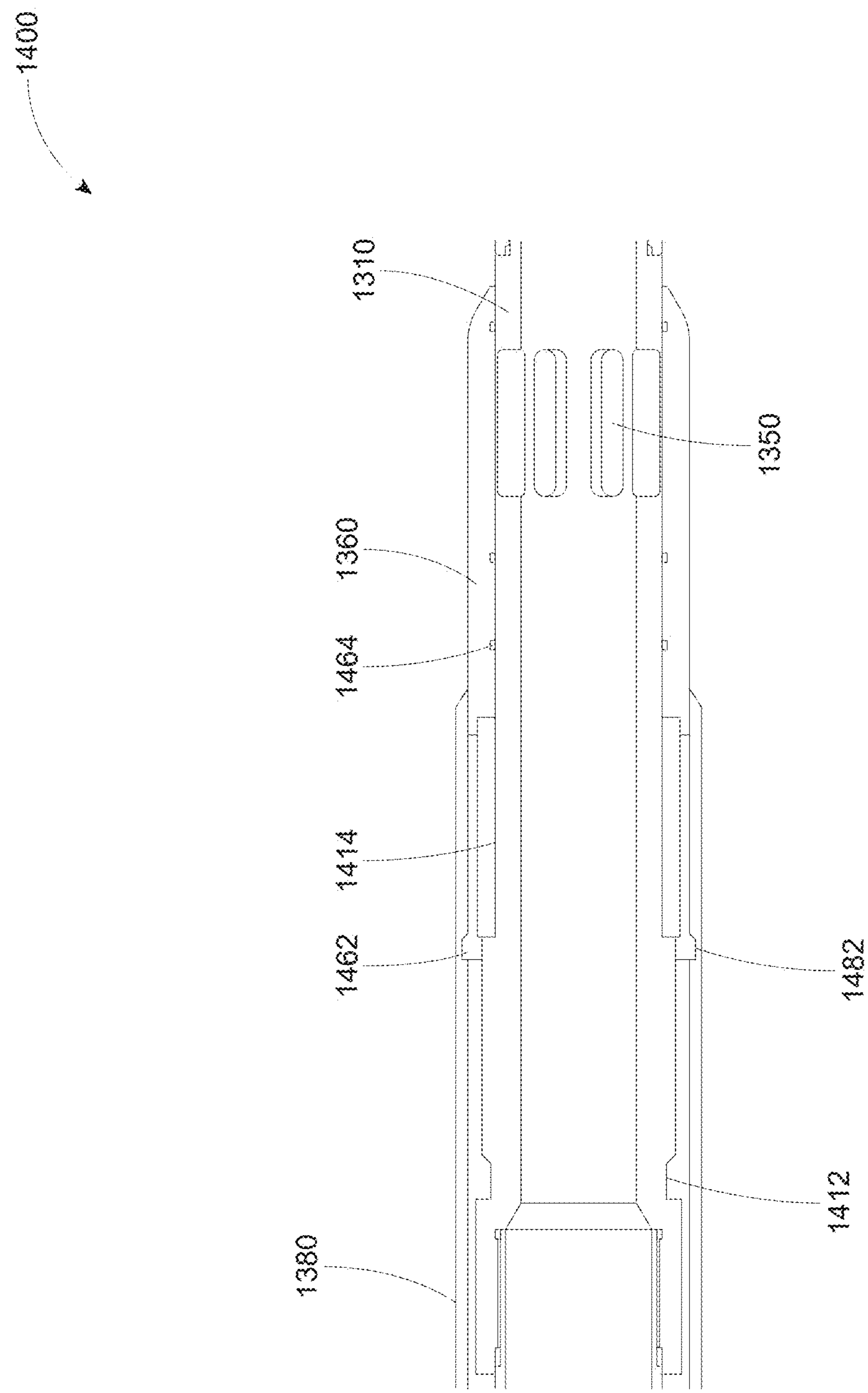

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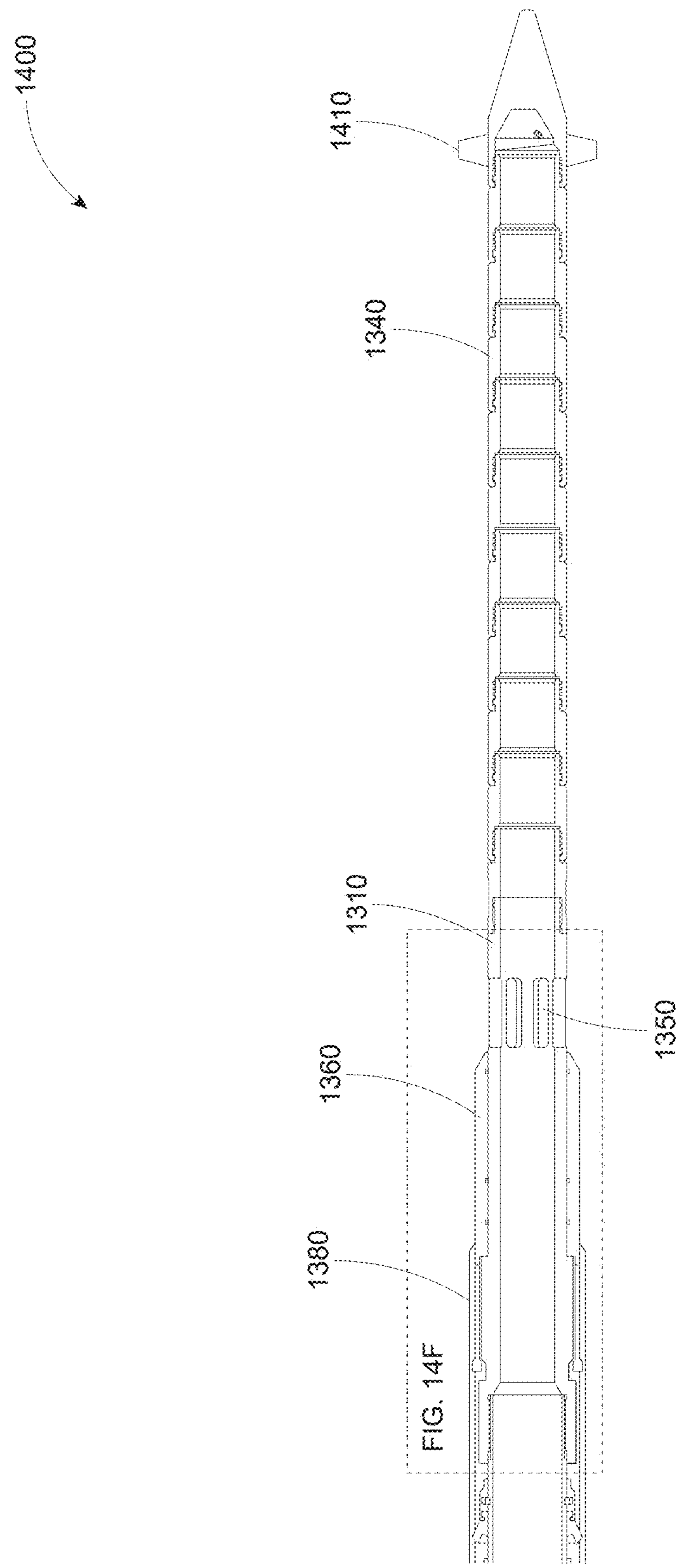

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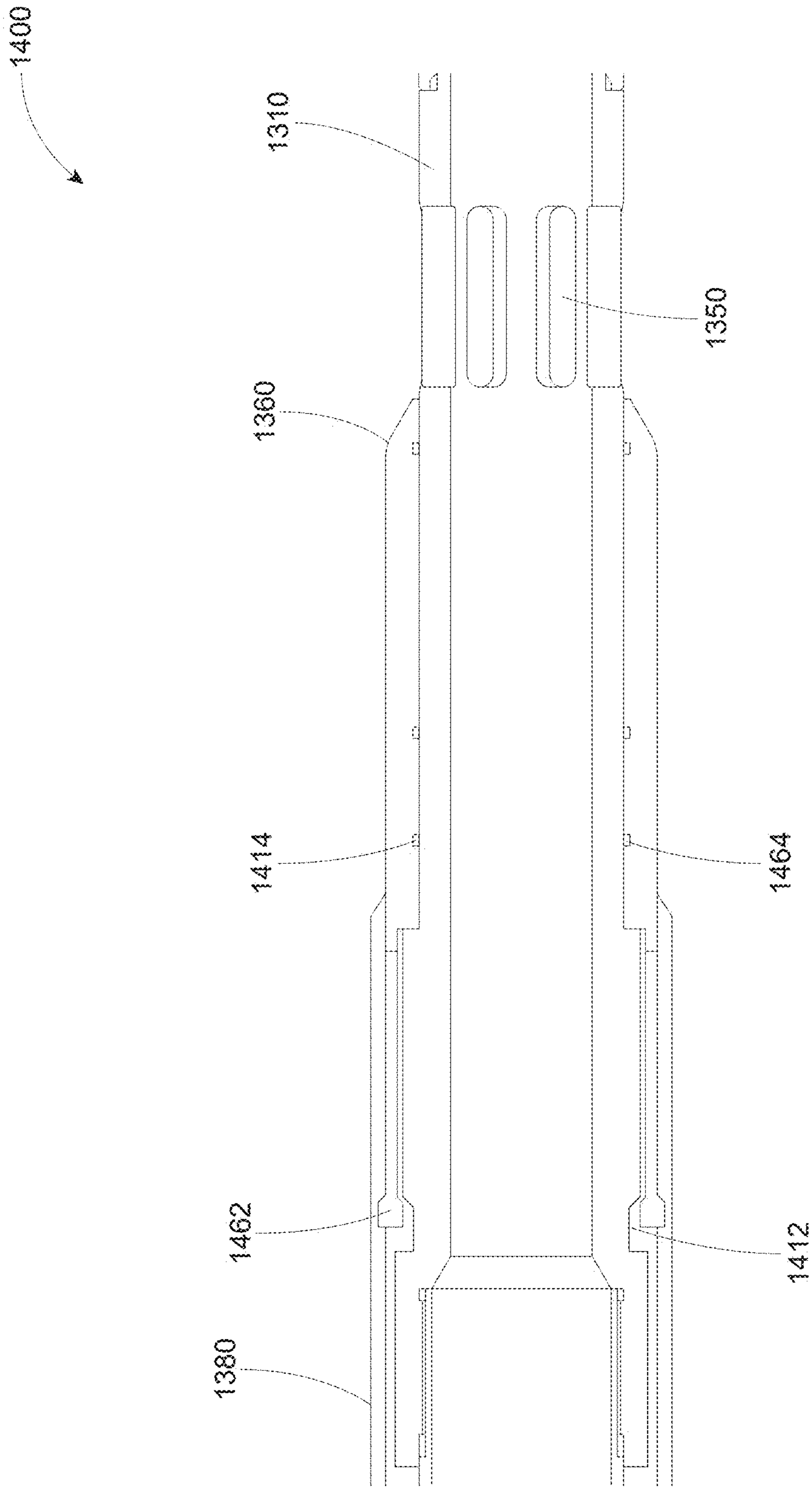

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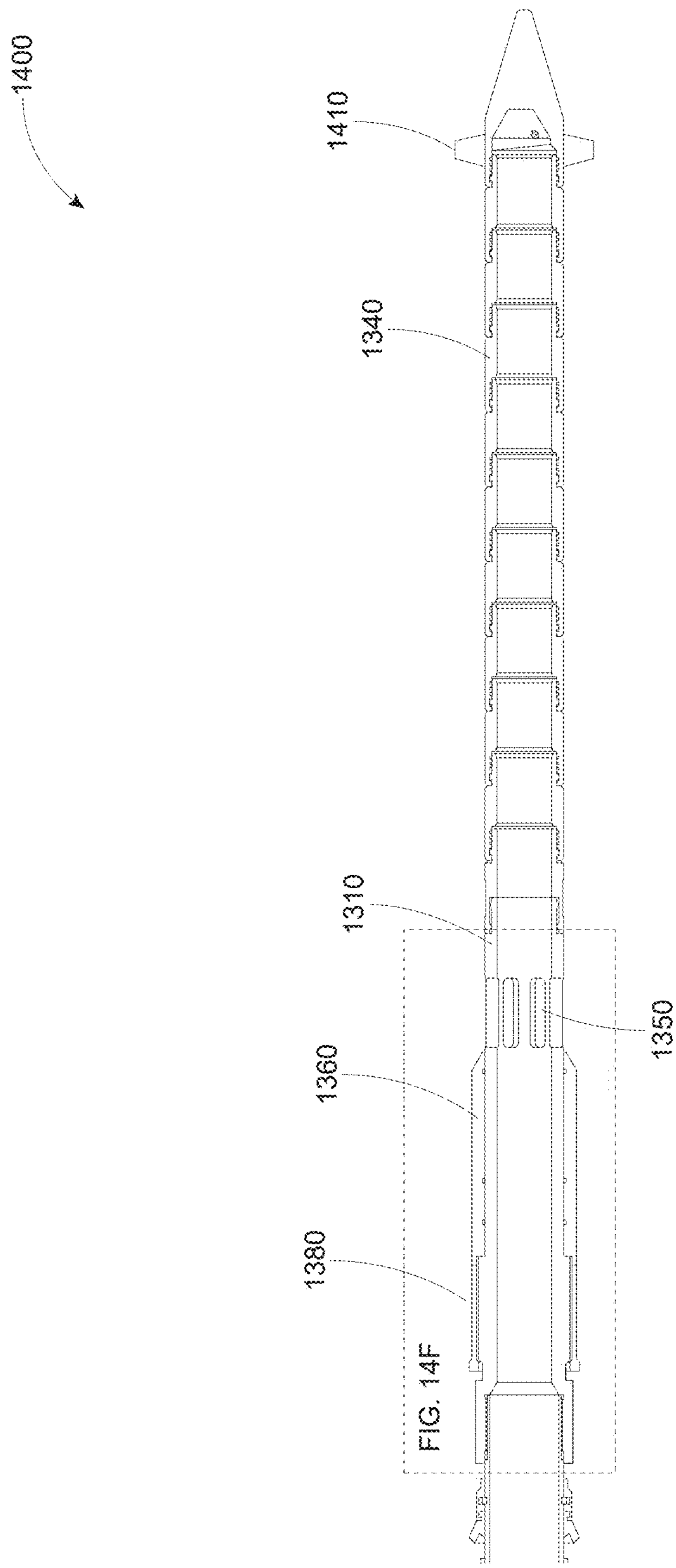

FIG. 14G

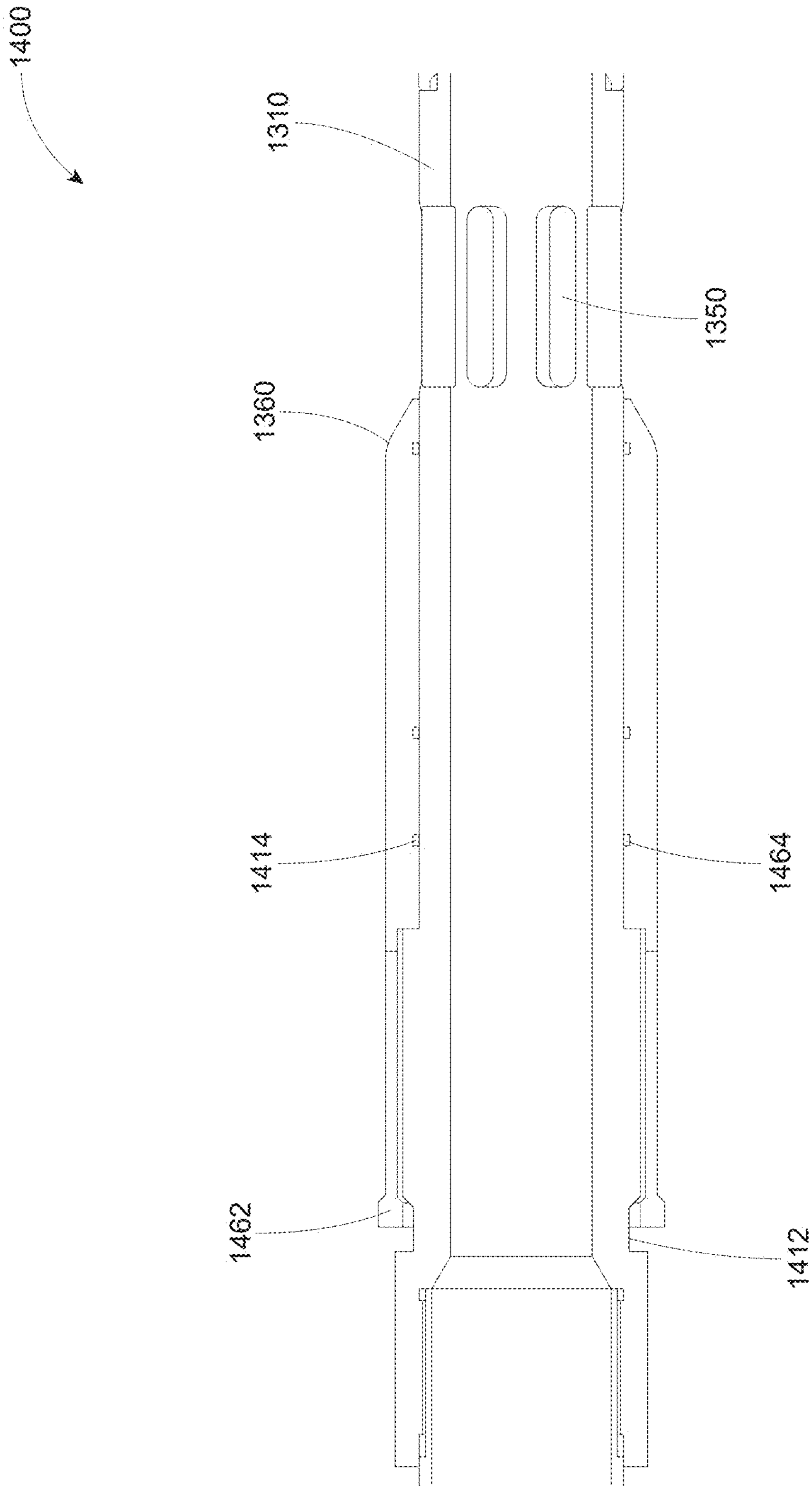

FIG. 14H

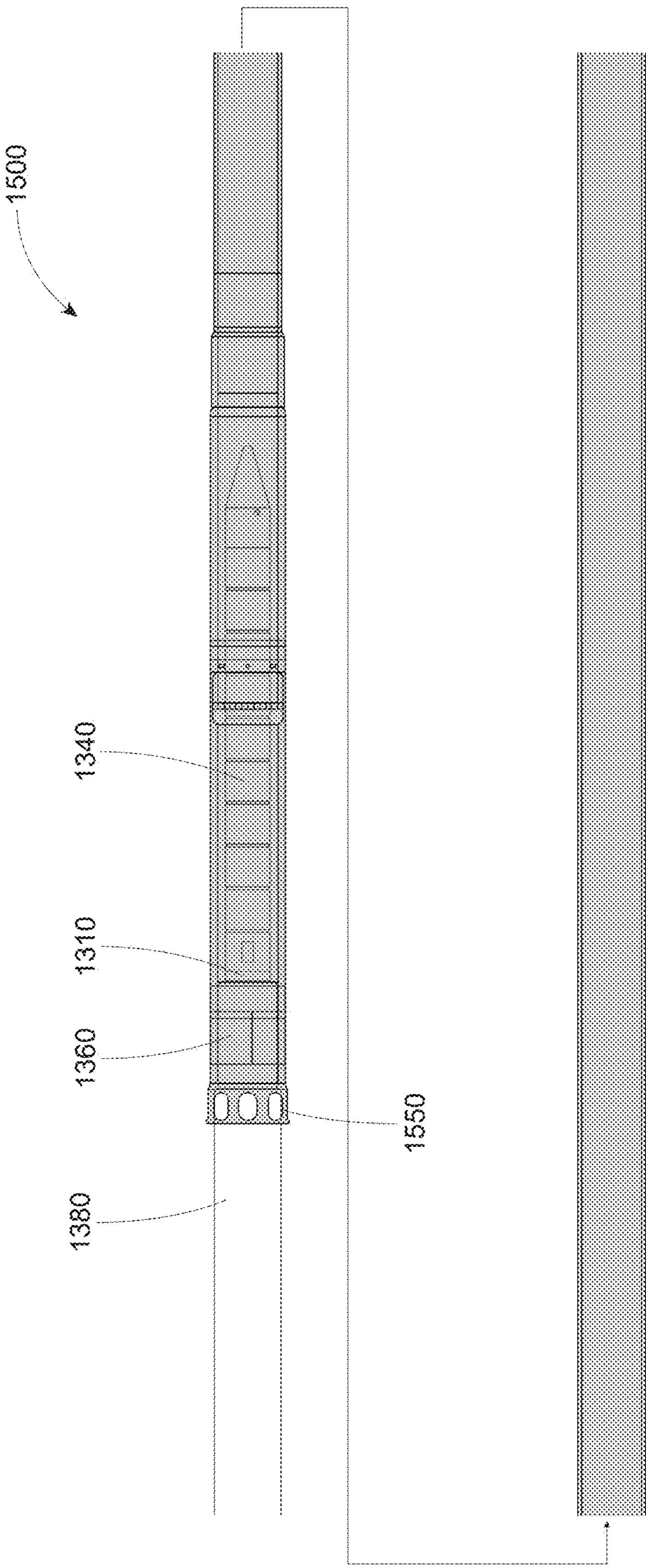

FIG. 15A

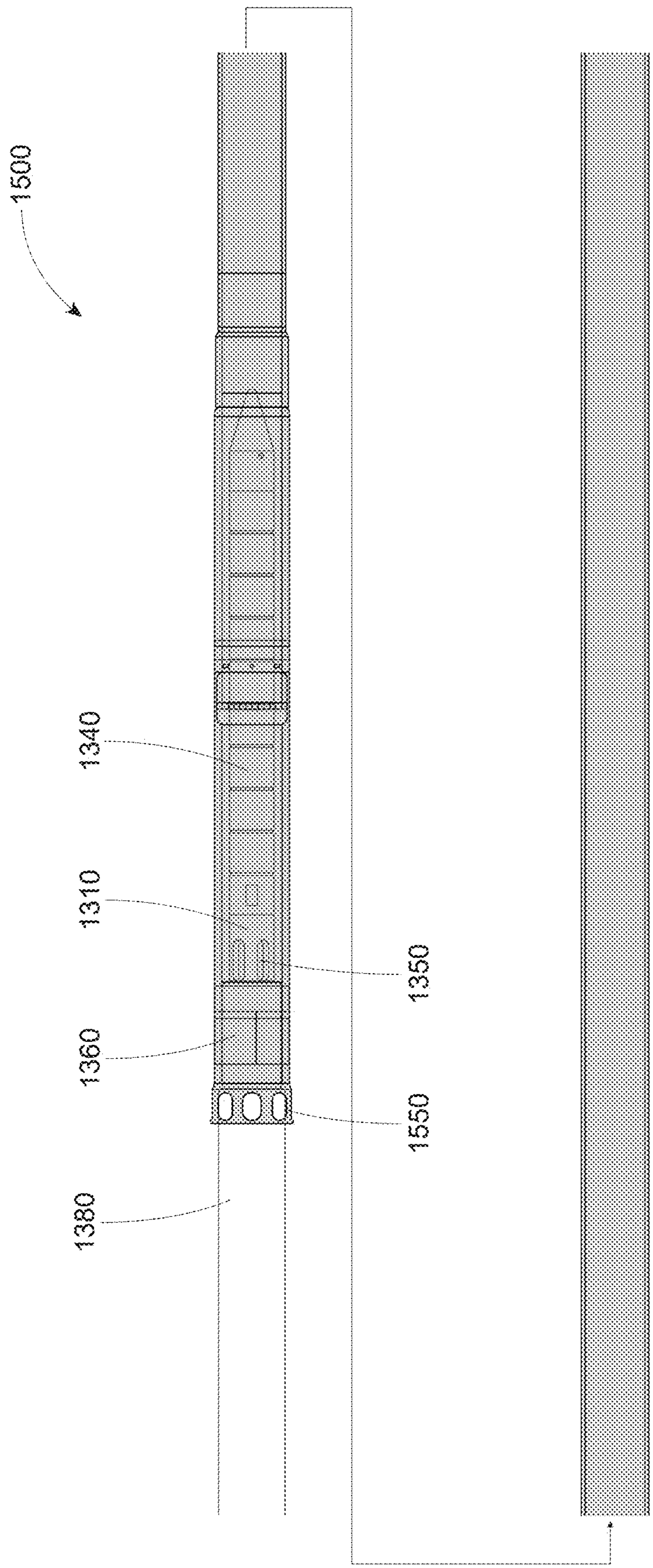

FIG. 15B

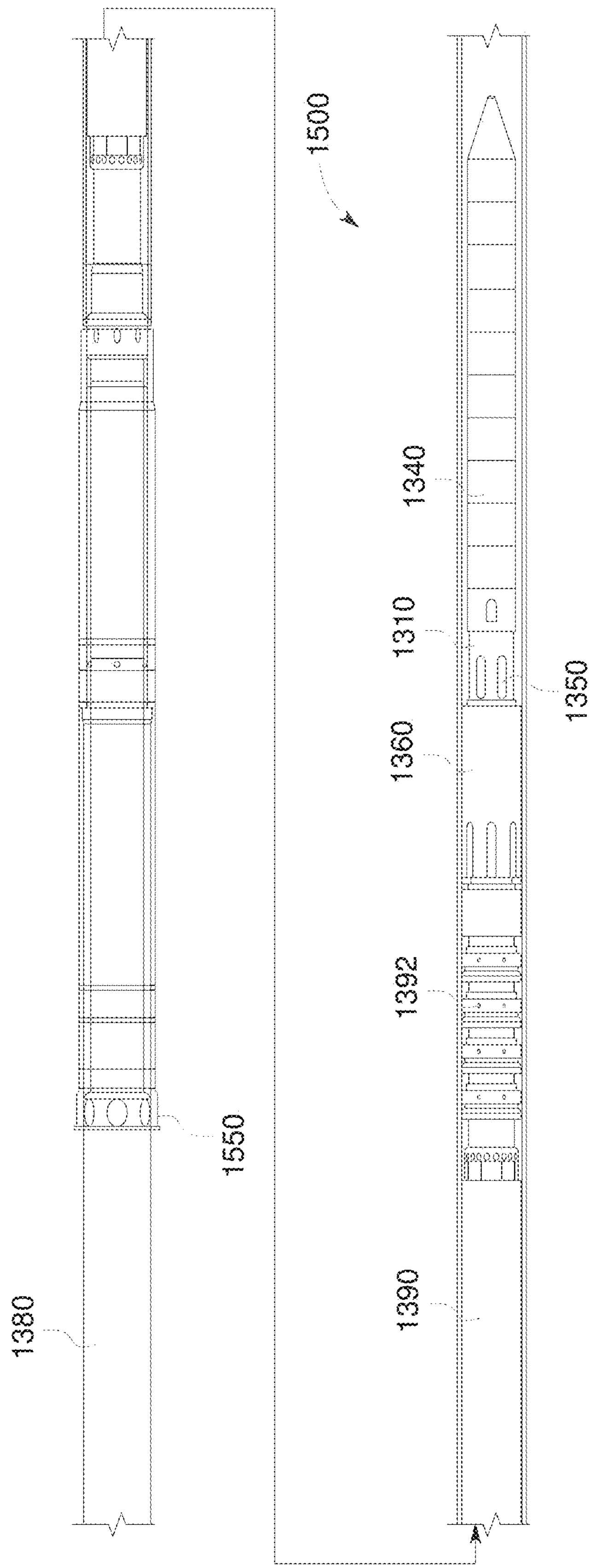

FIG. 15C

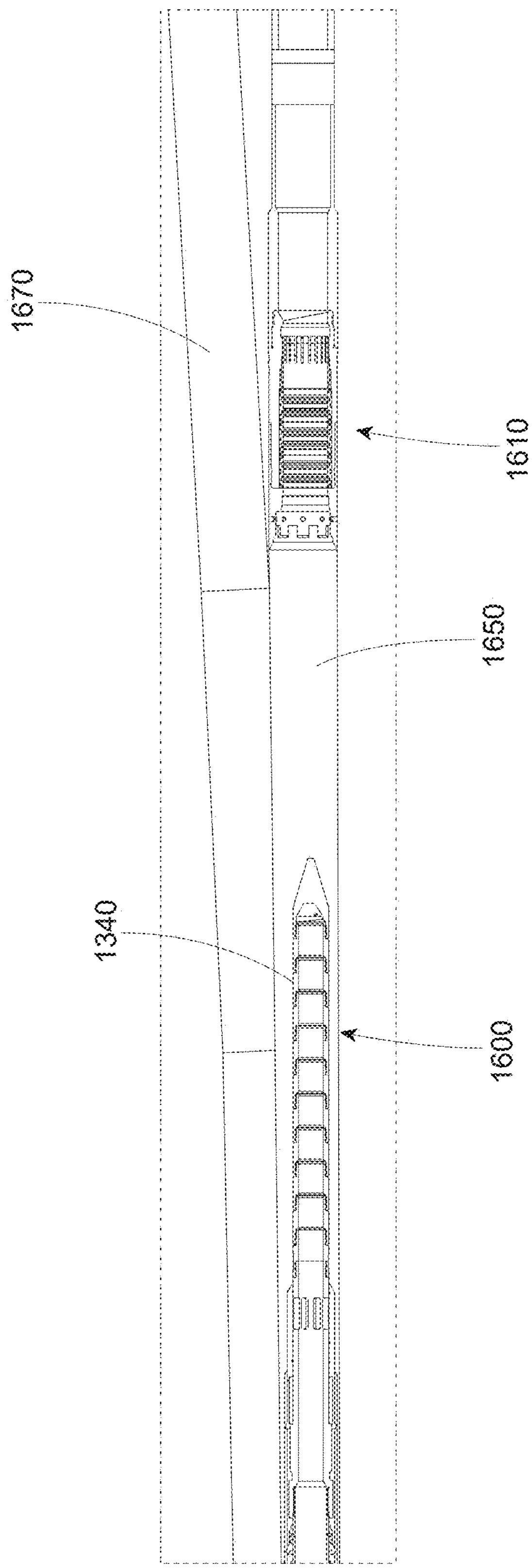

FIG. 16A

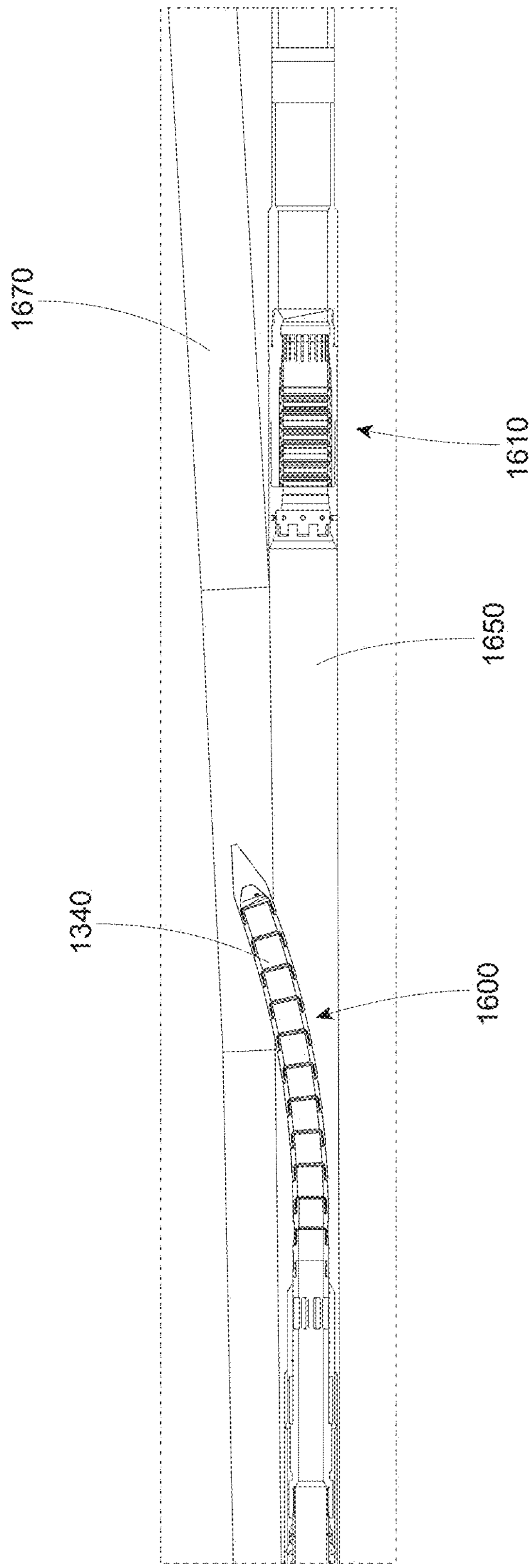

FIG. 16B

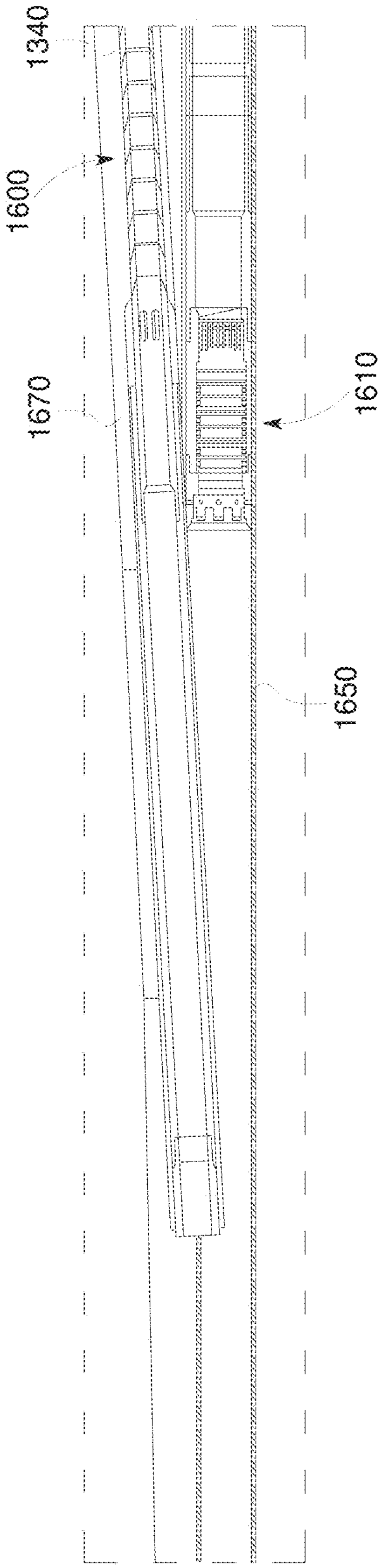

FIG. 16C

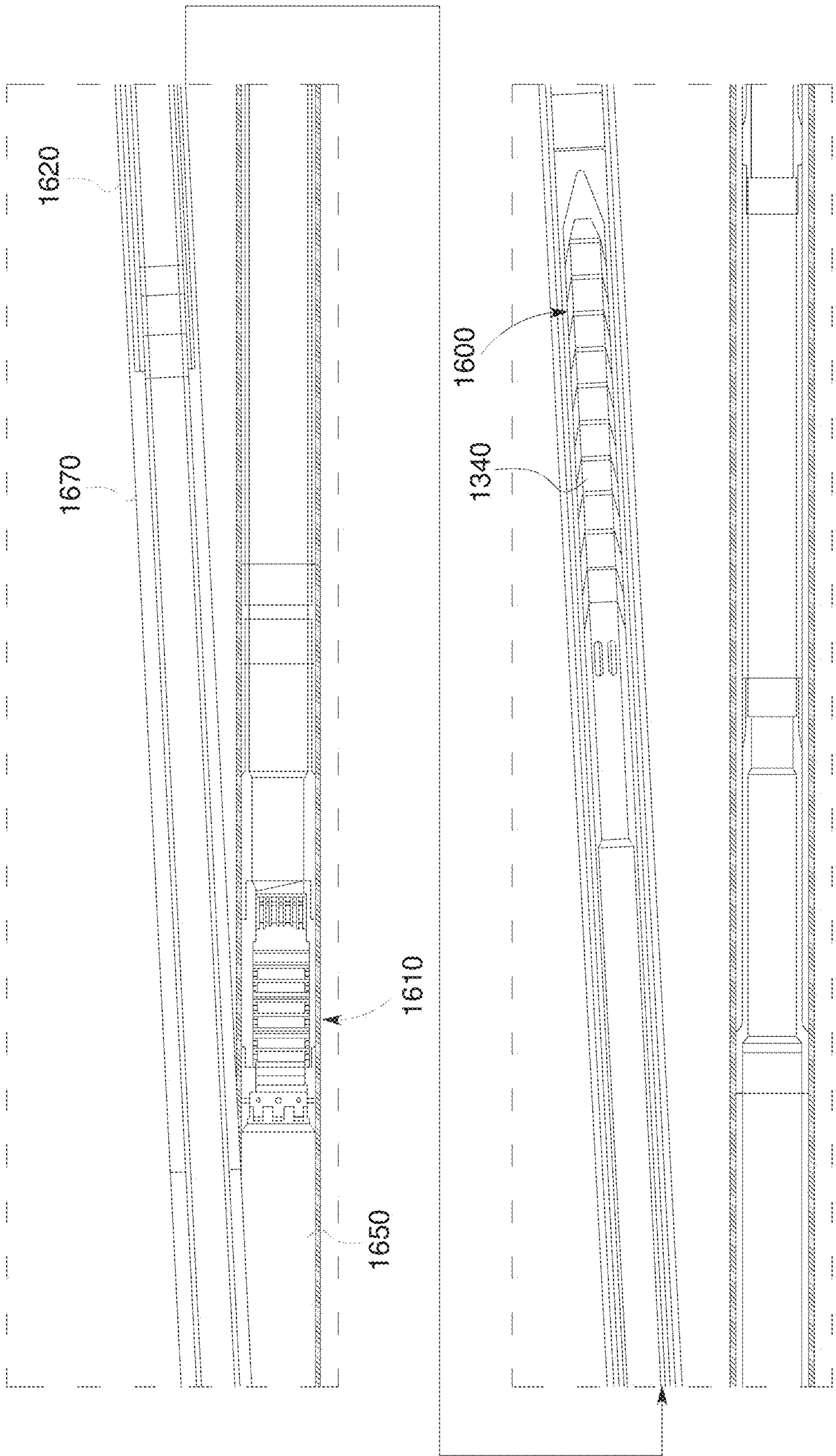

FIG. 16D

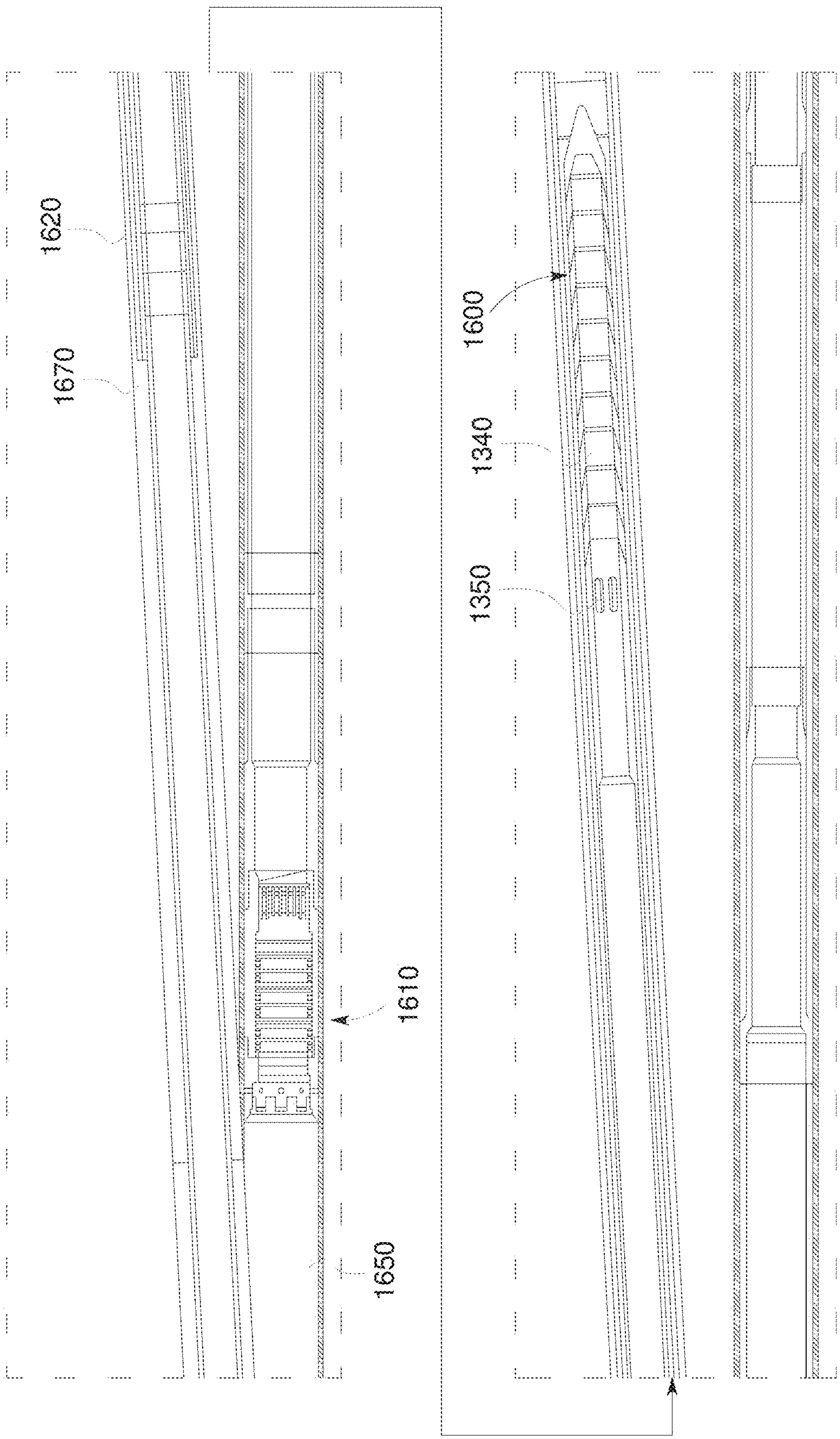

FIG. 16E

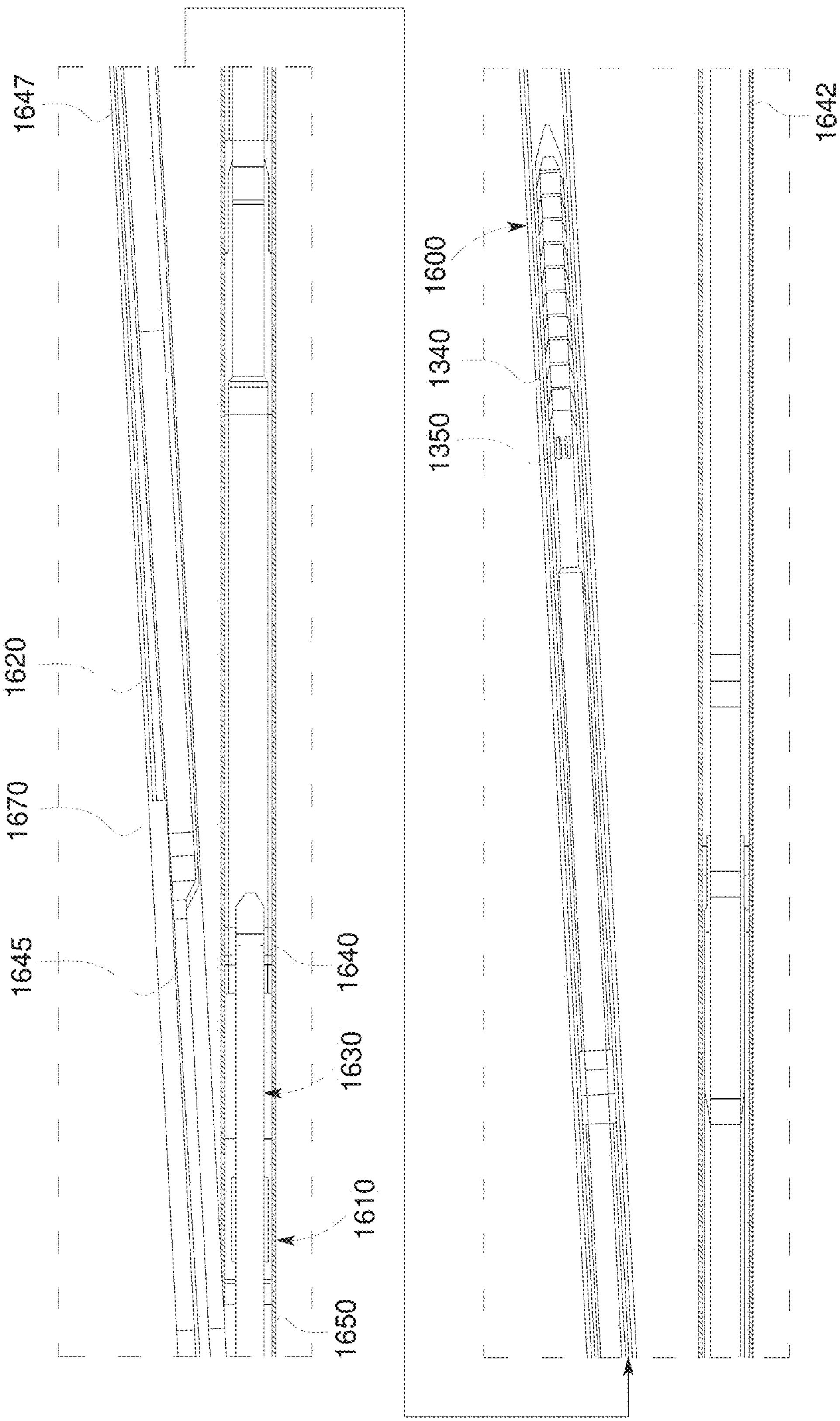

FIG. 16F

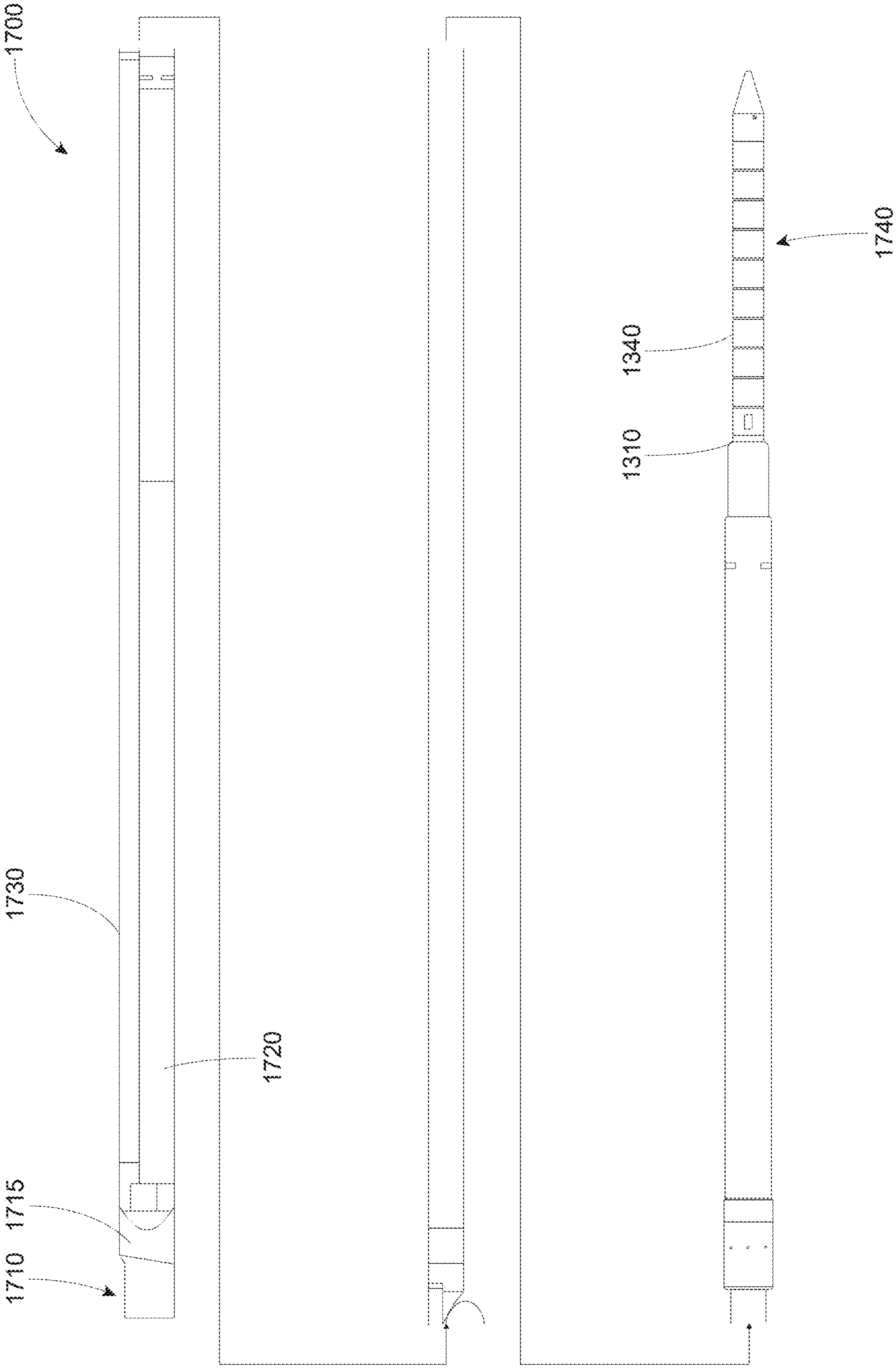

FIG. 17A

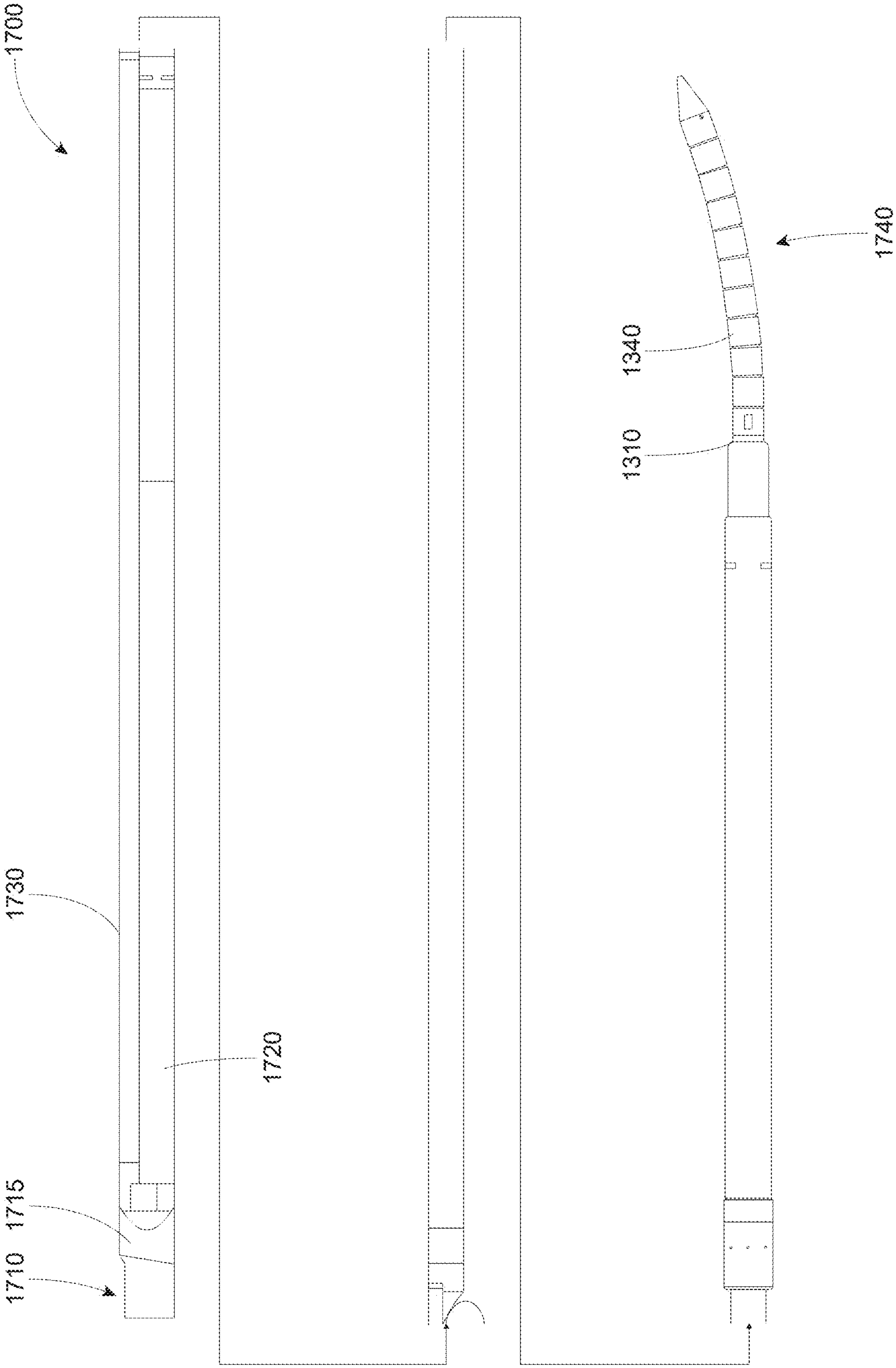

FIG. 17B

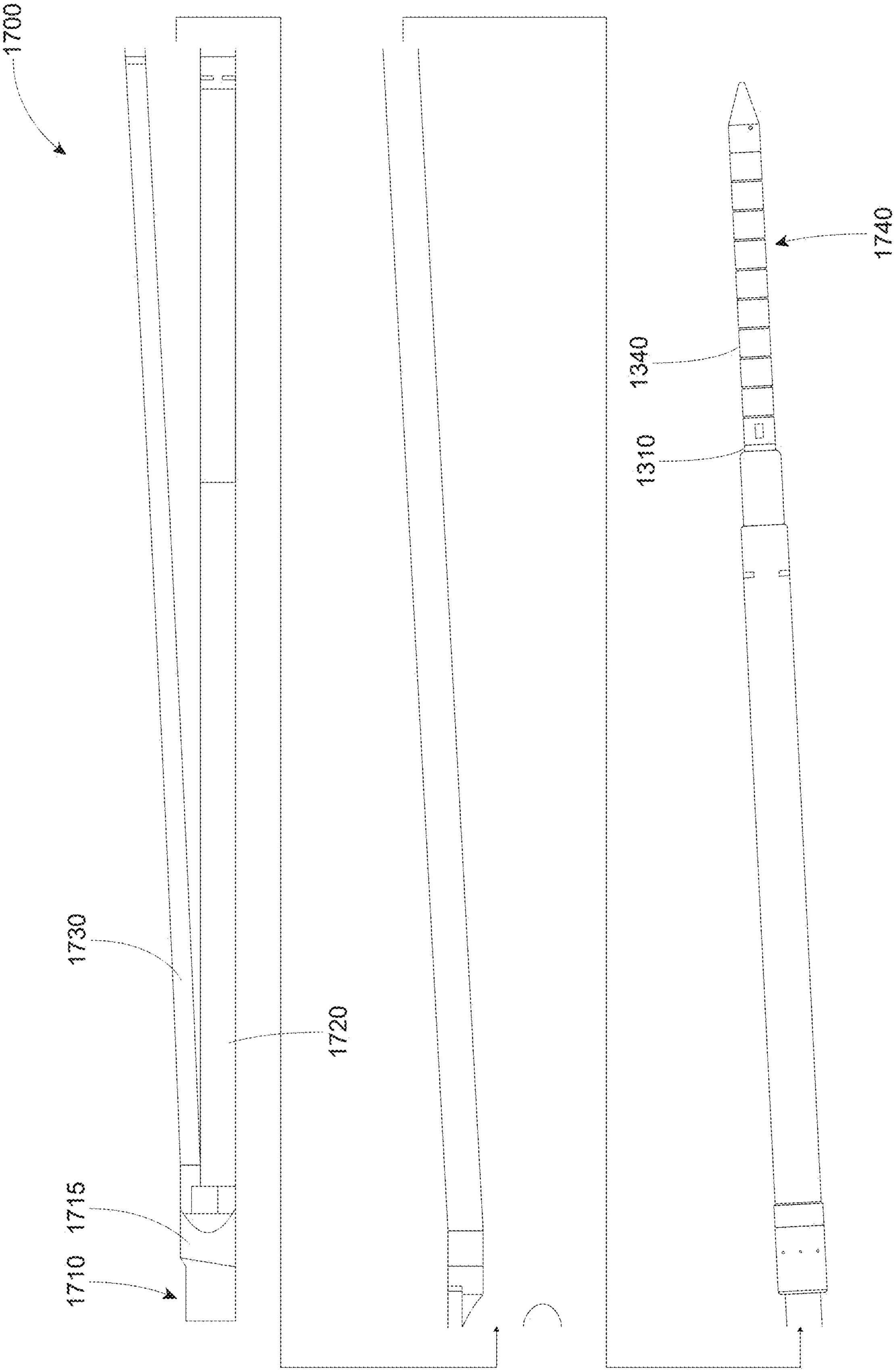

FIG. 17C

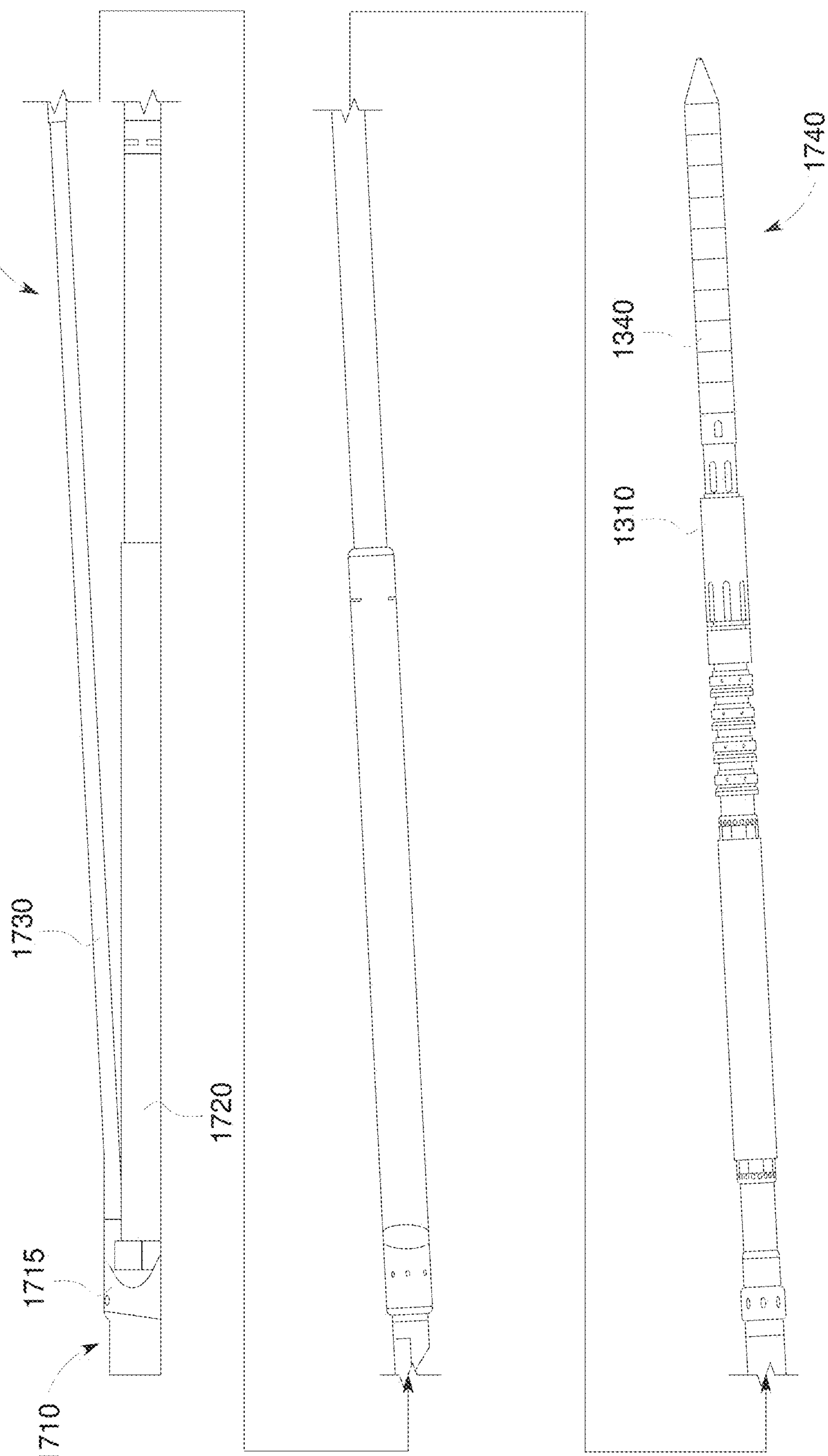

FIG. 17D

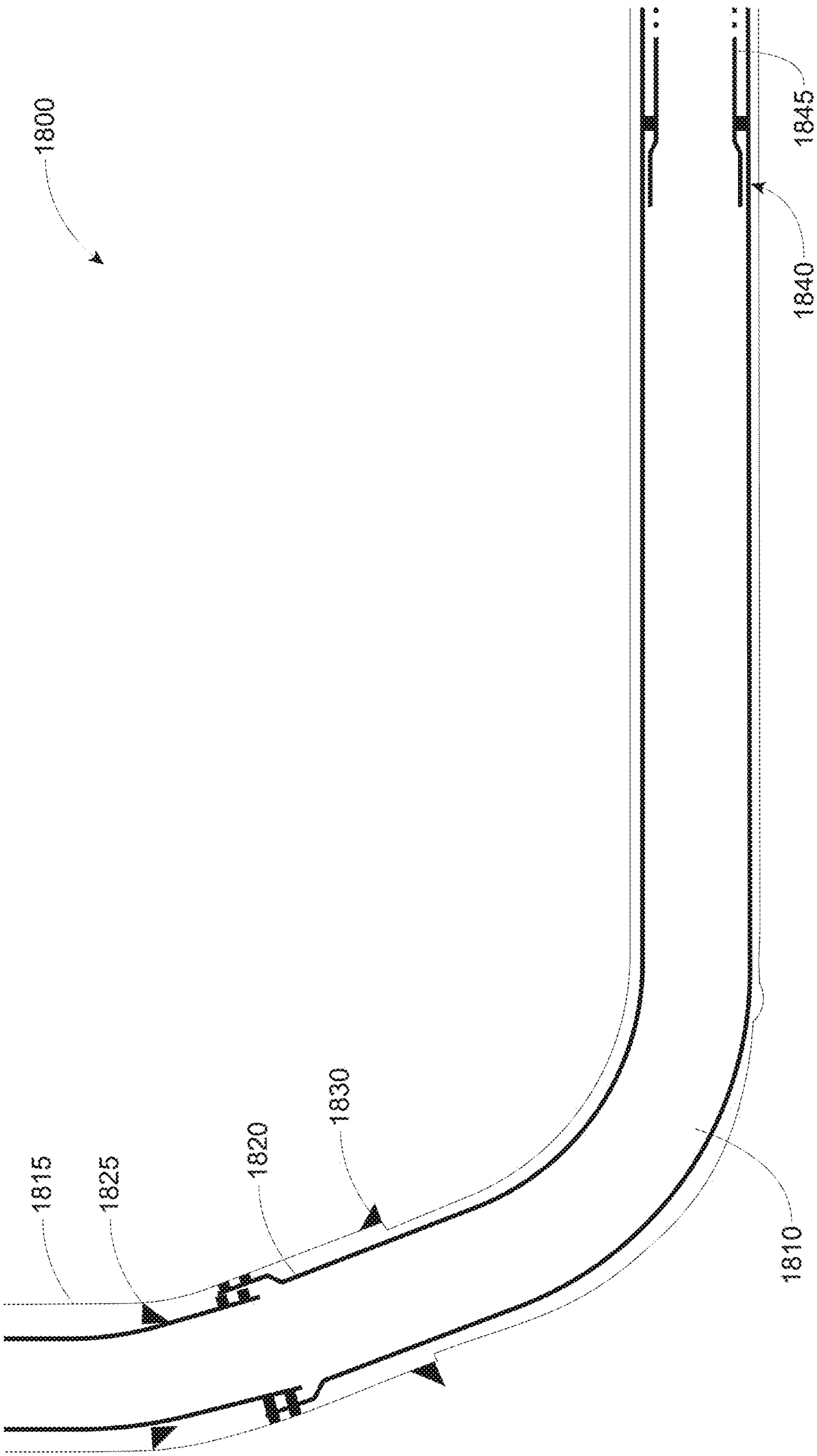

FIG. 18

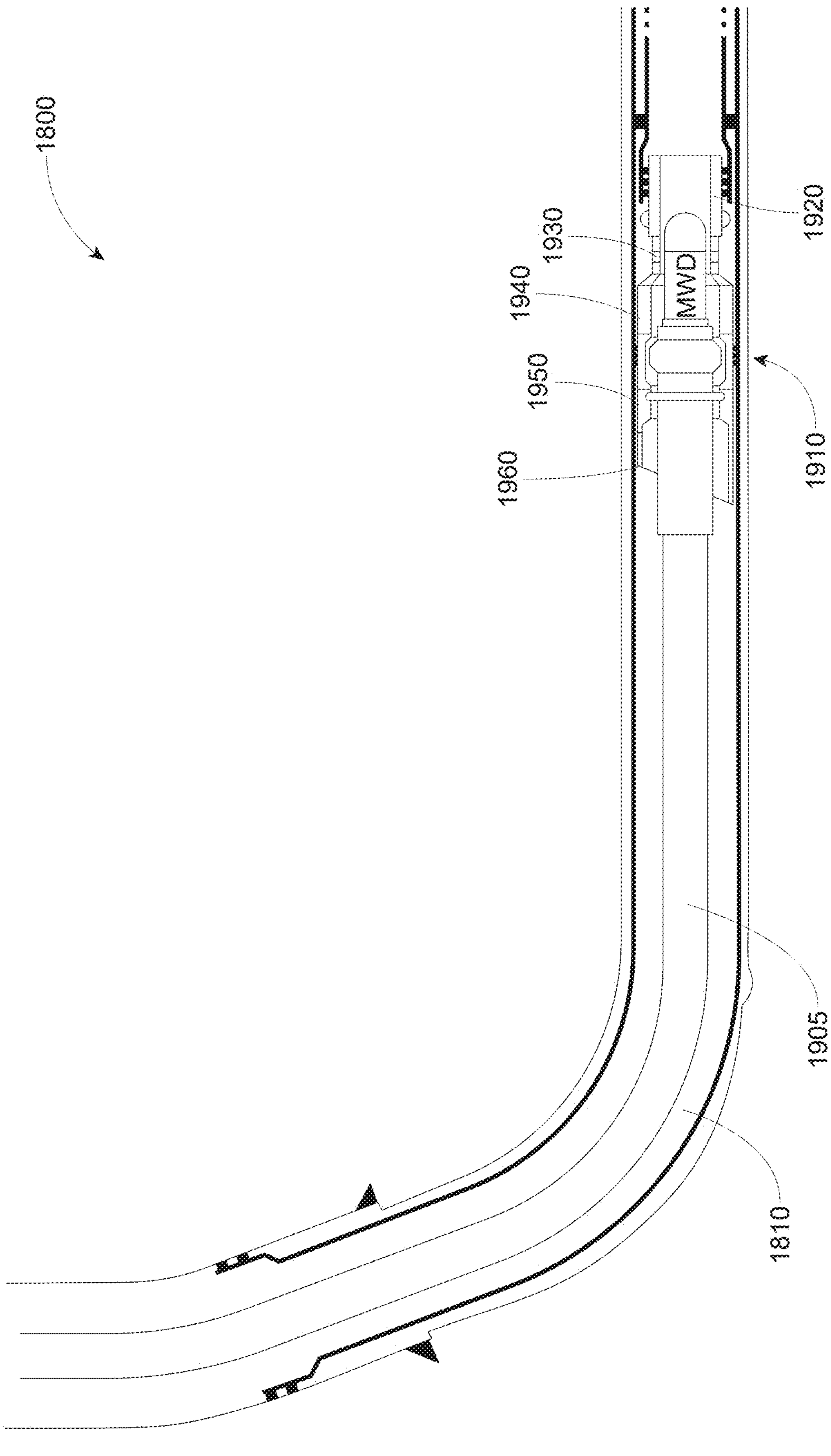

FIG. 19

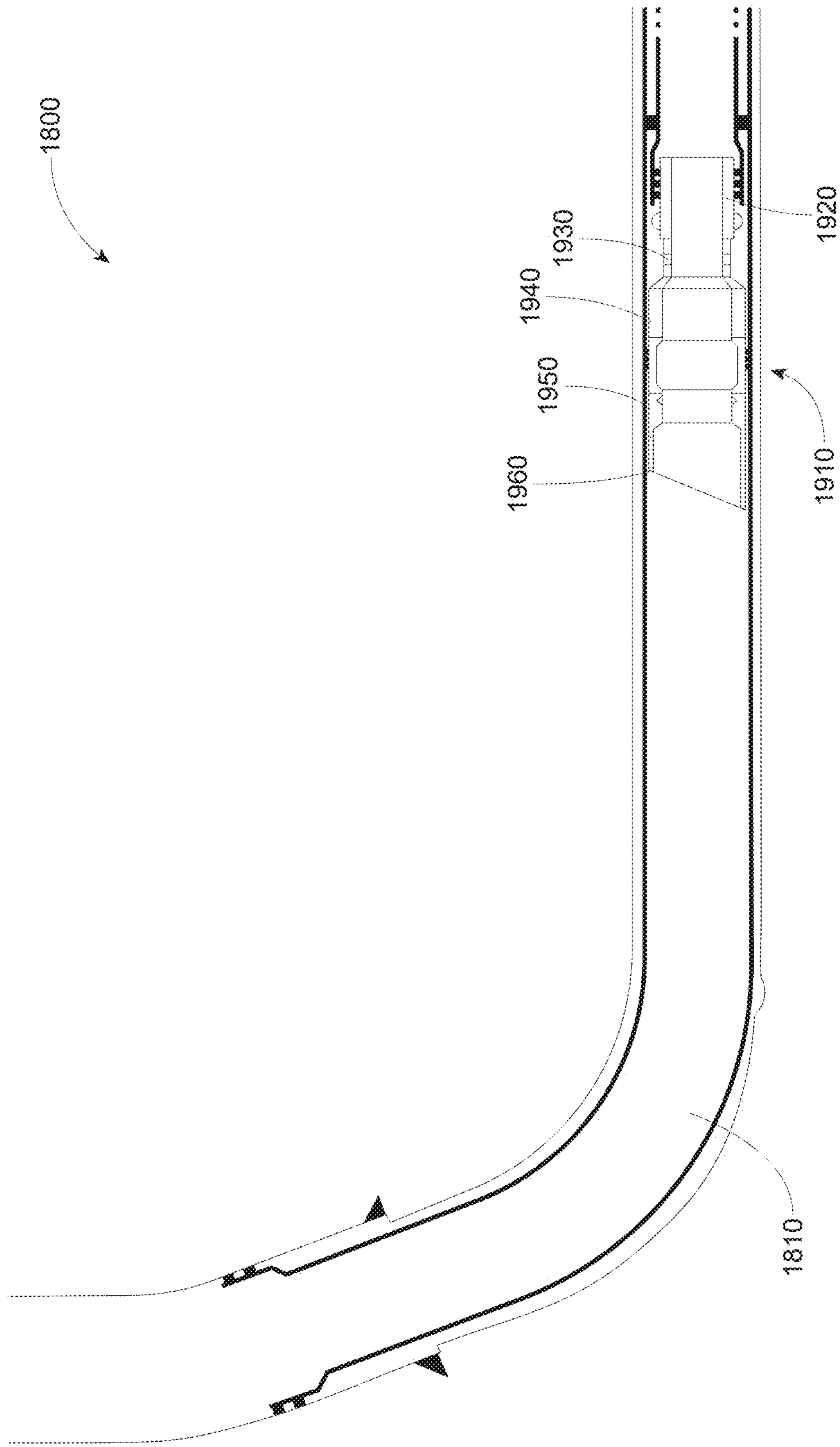

FIG. 20

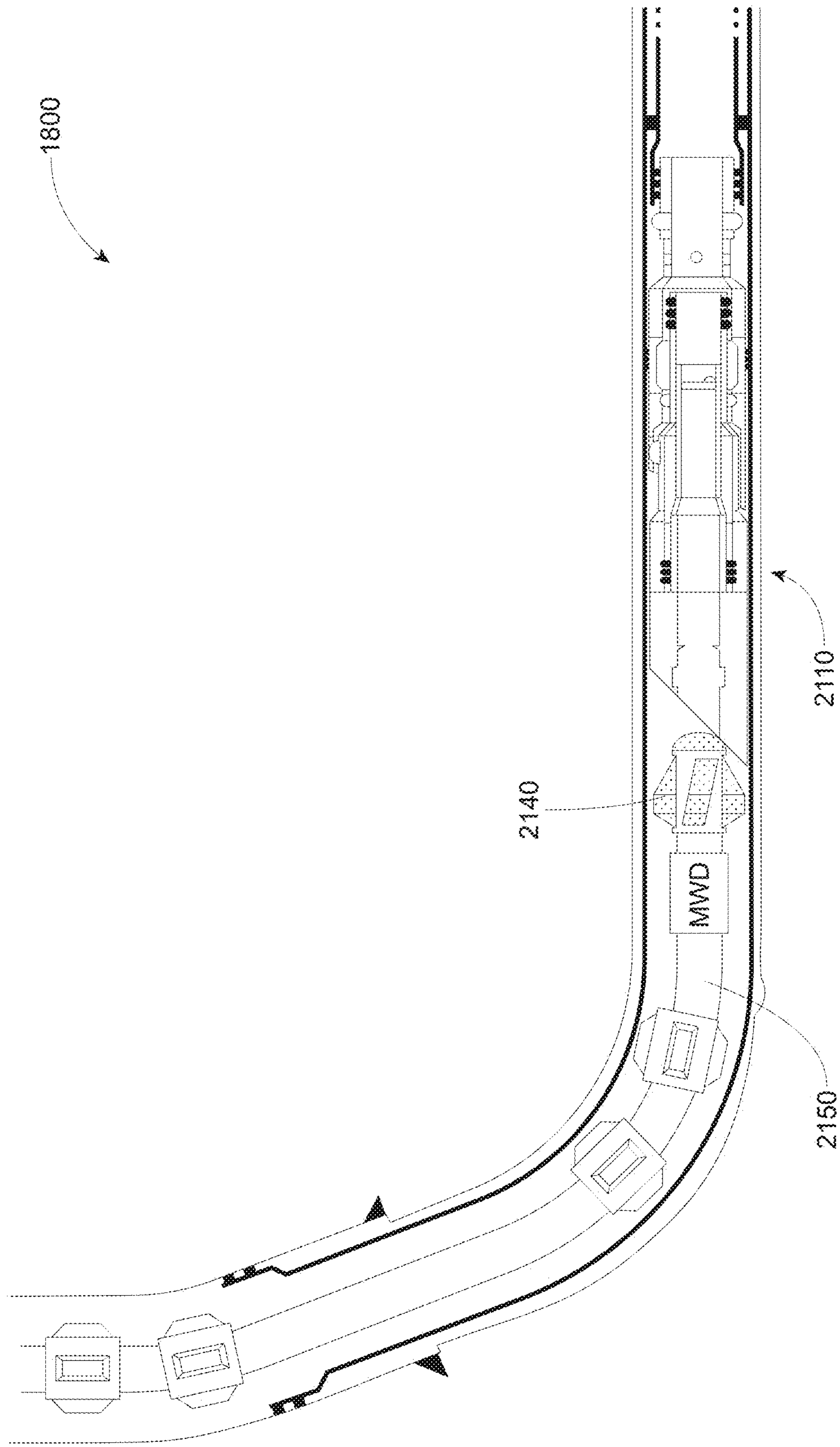

FIG. 21

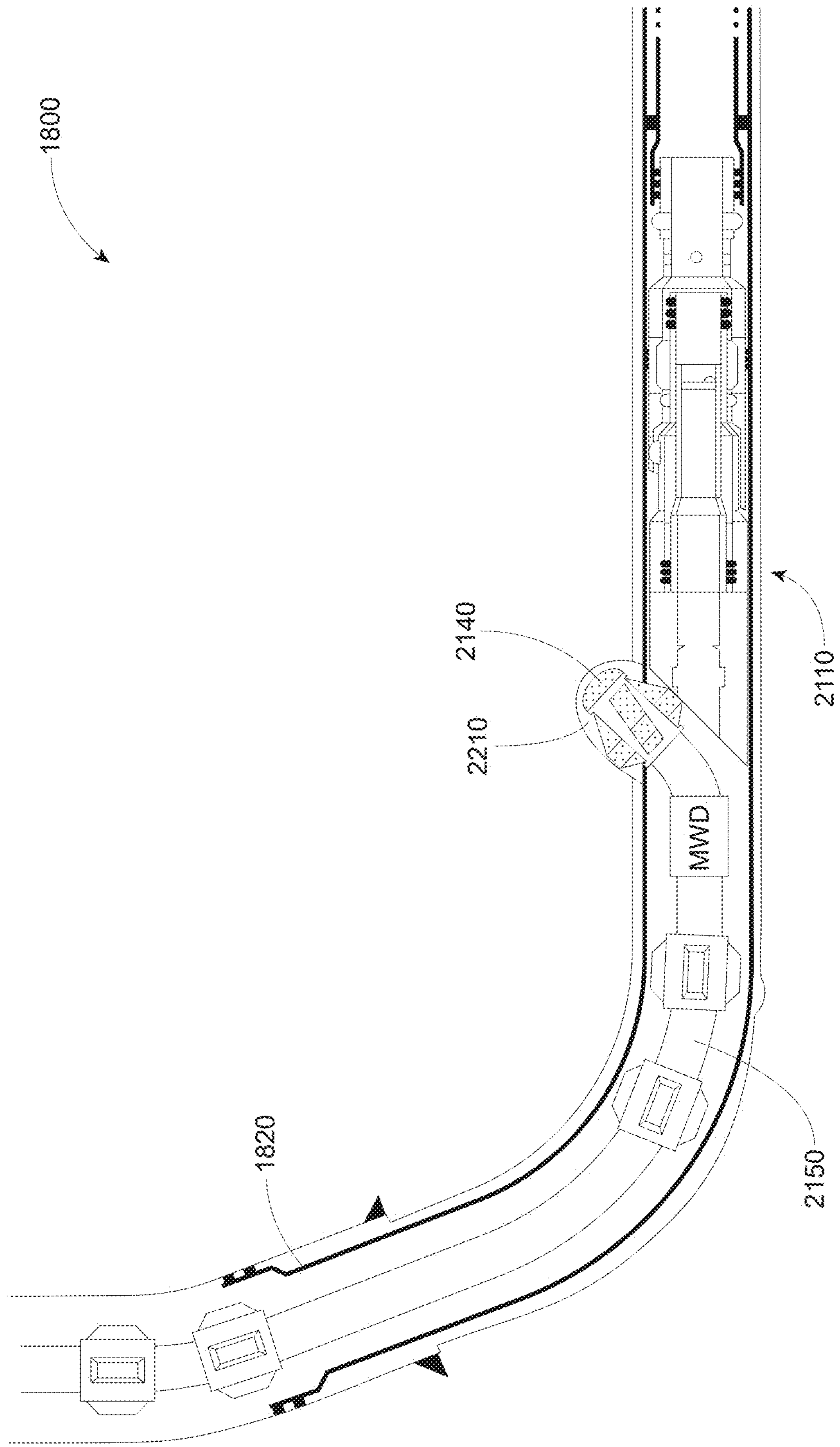

FIG. 22

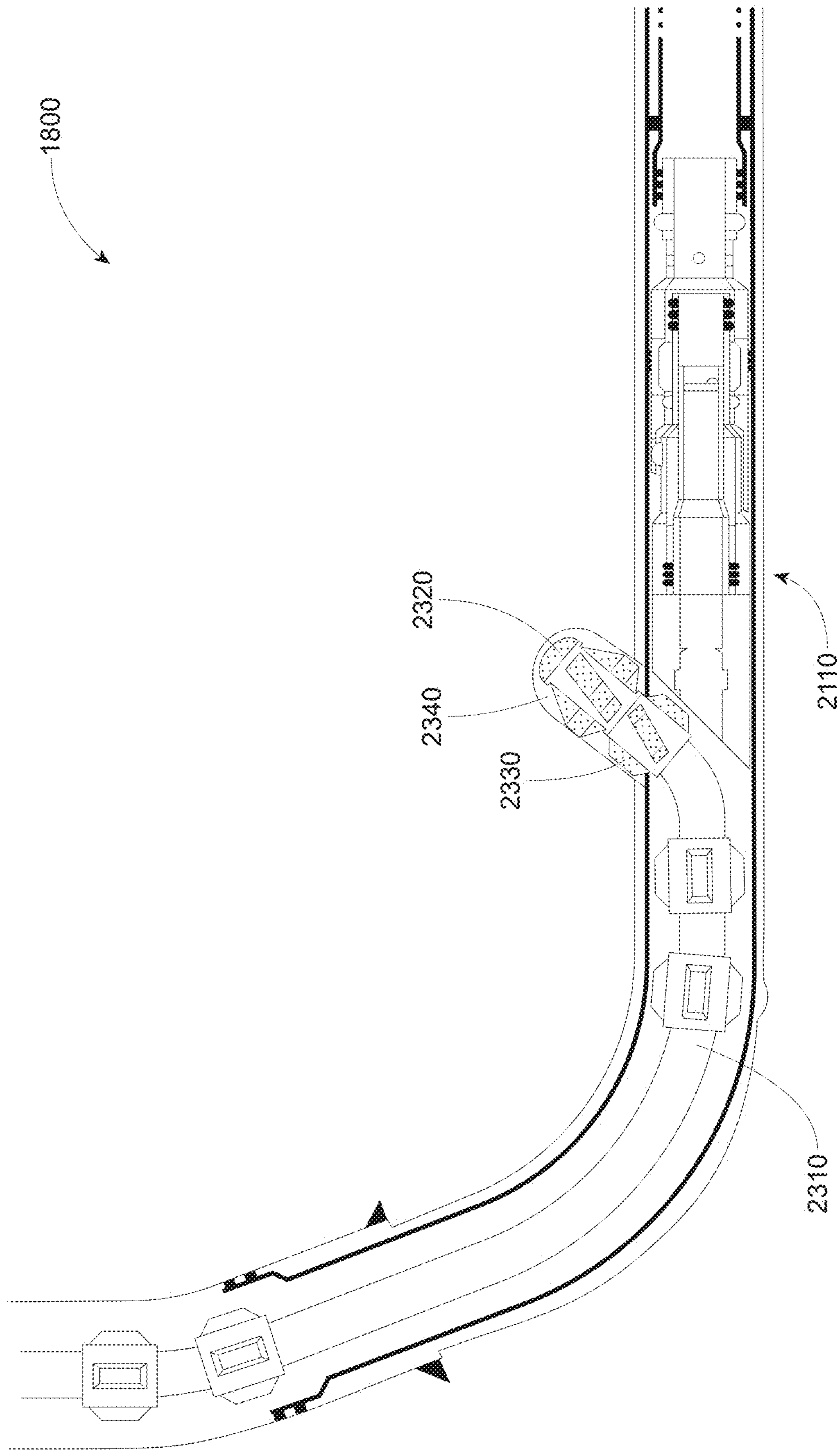

FIG. 23

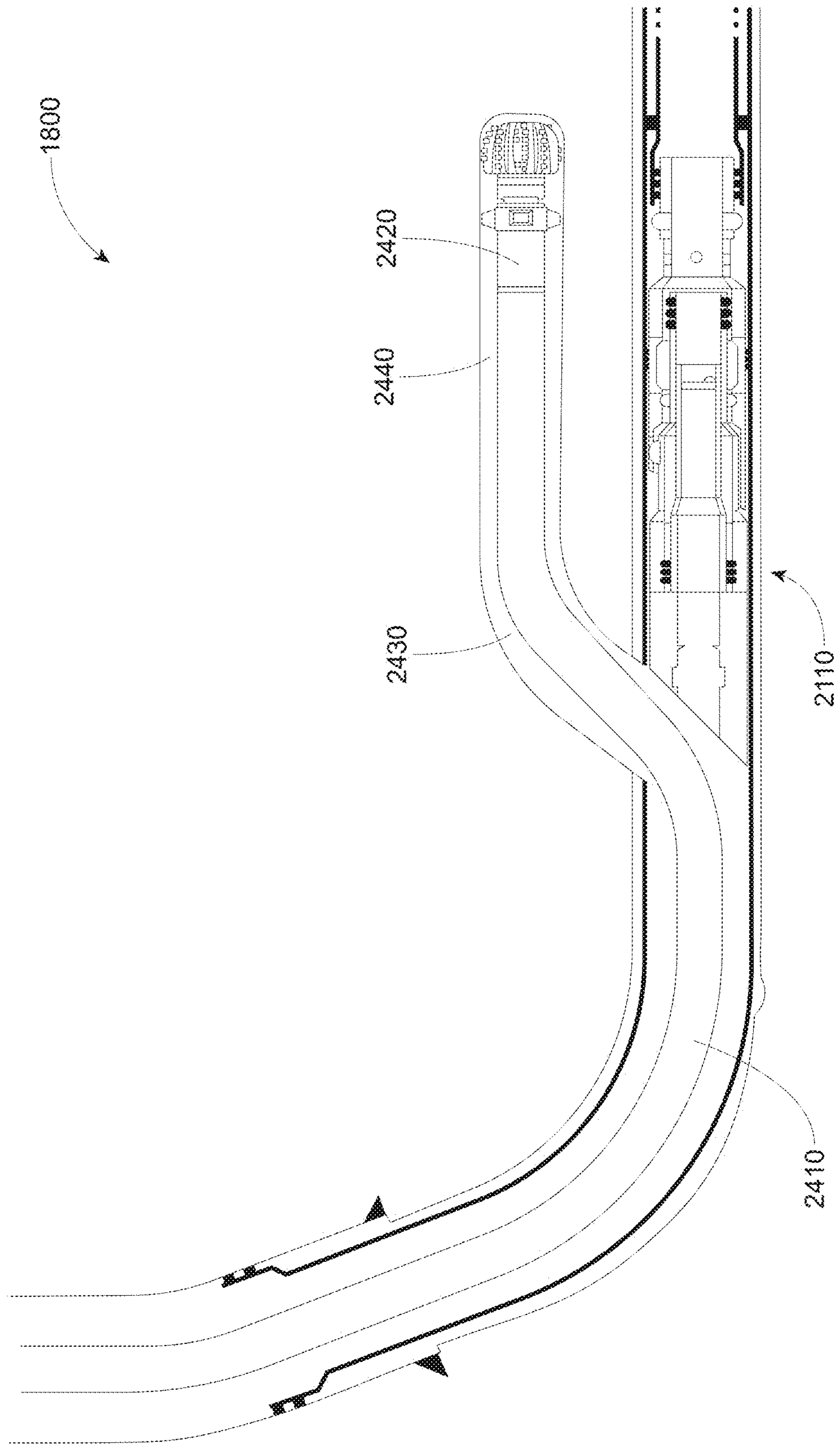

FIG. 24

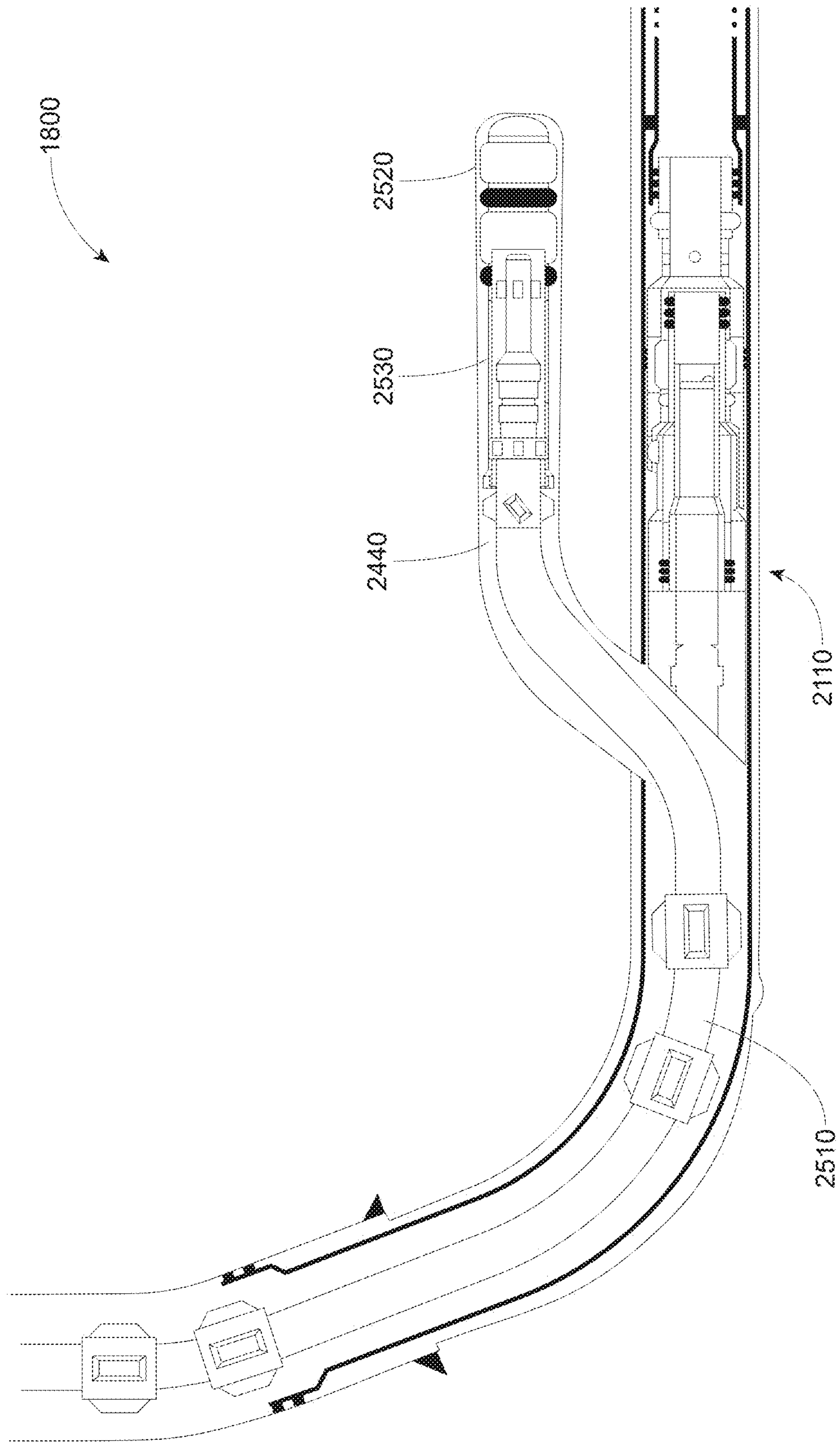

FIG. 25

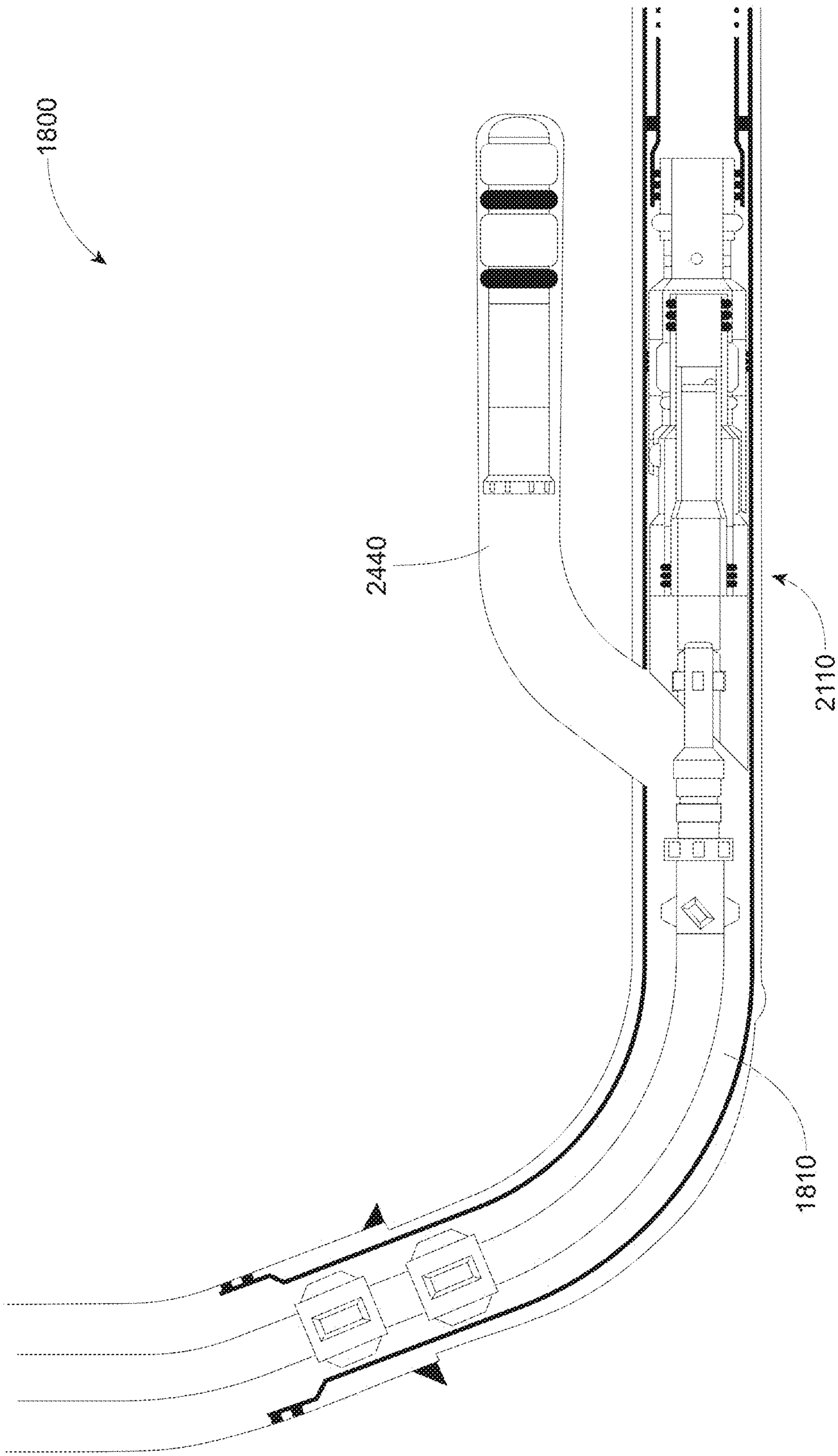

FIG. 26

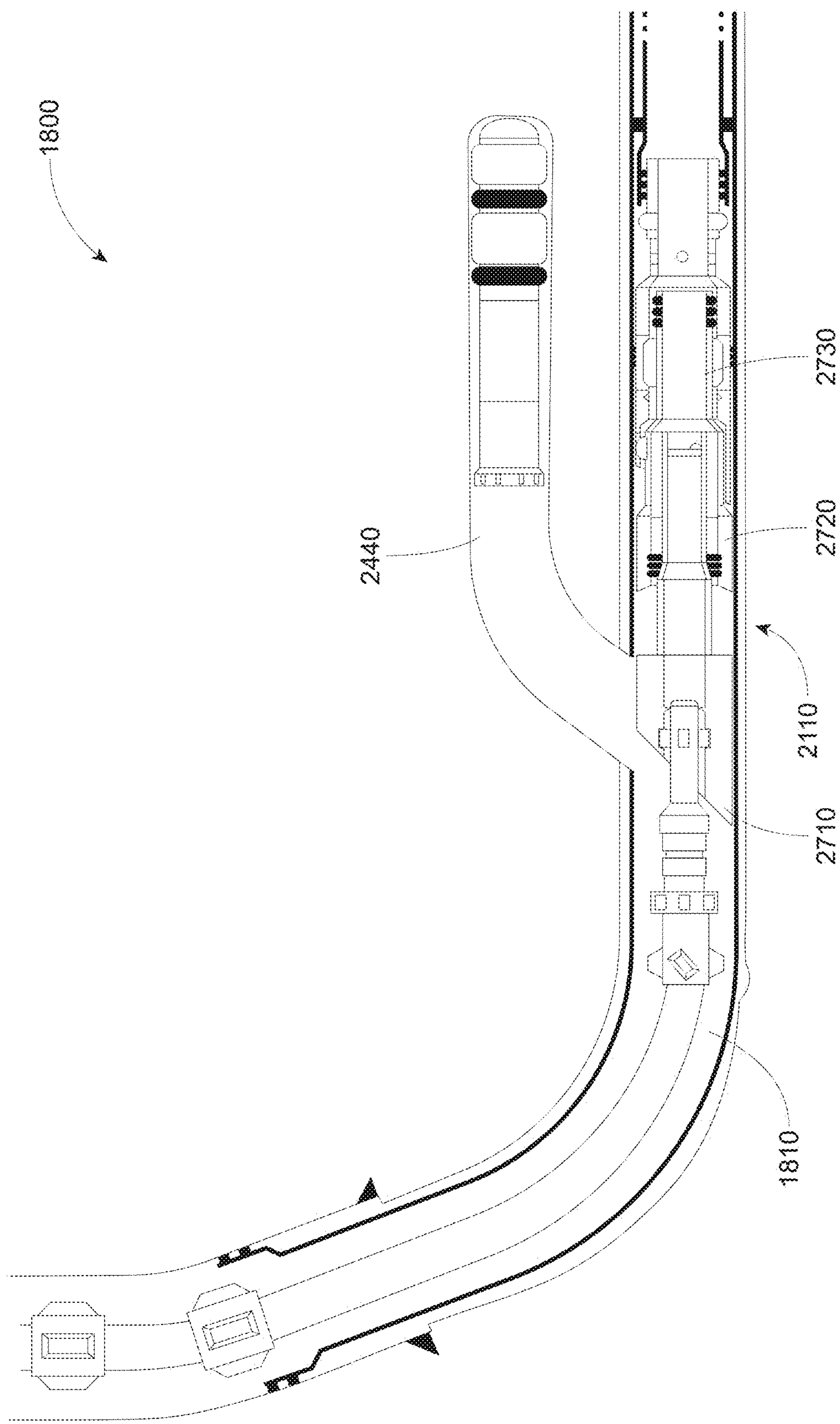

FIG. 27

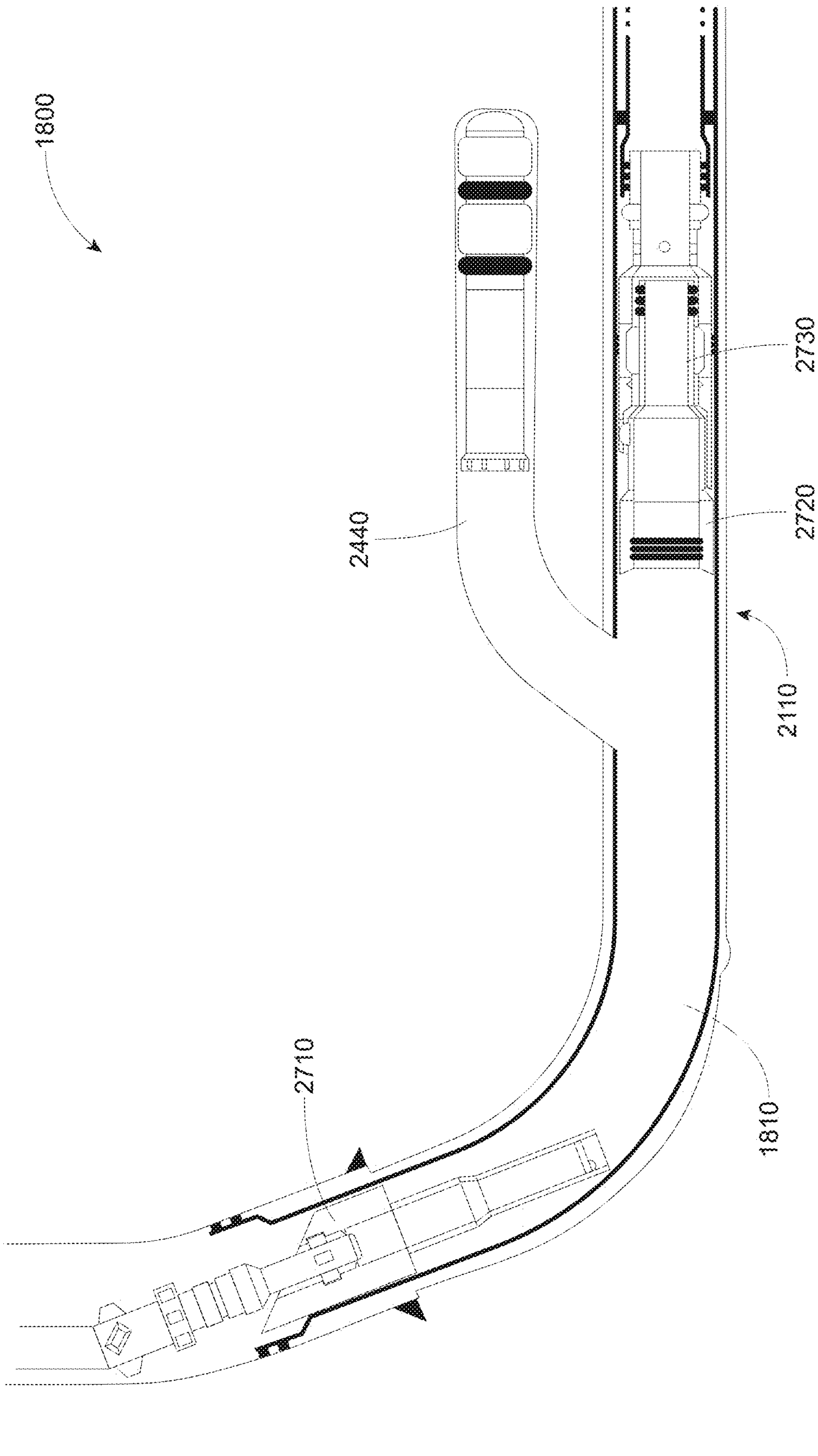

FIG. 28

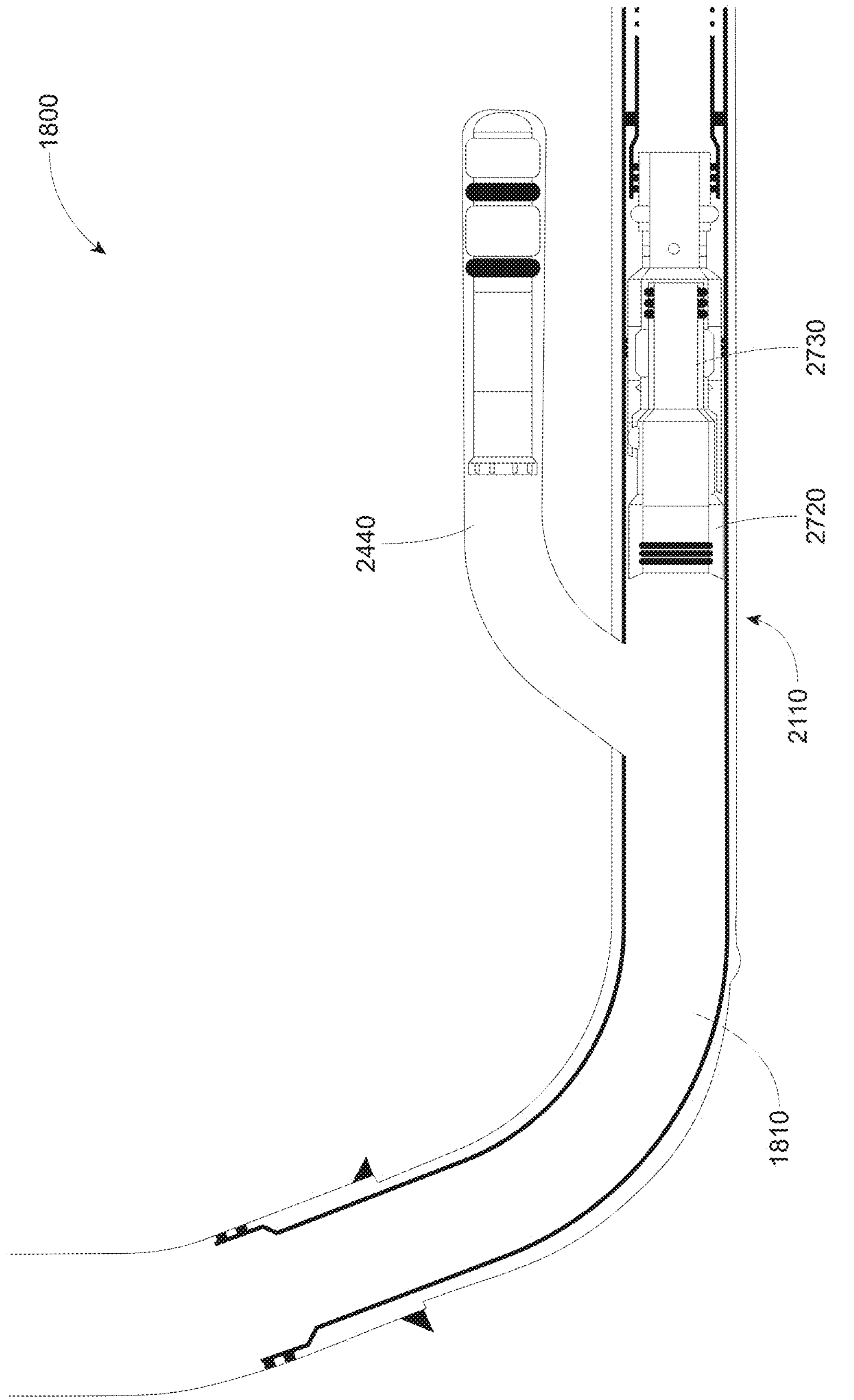

FIG. 29

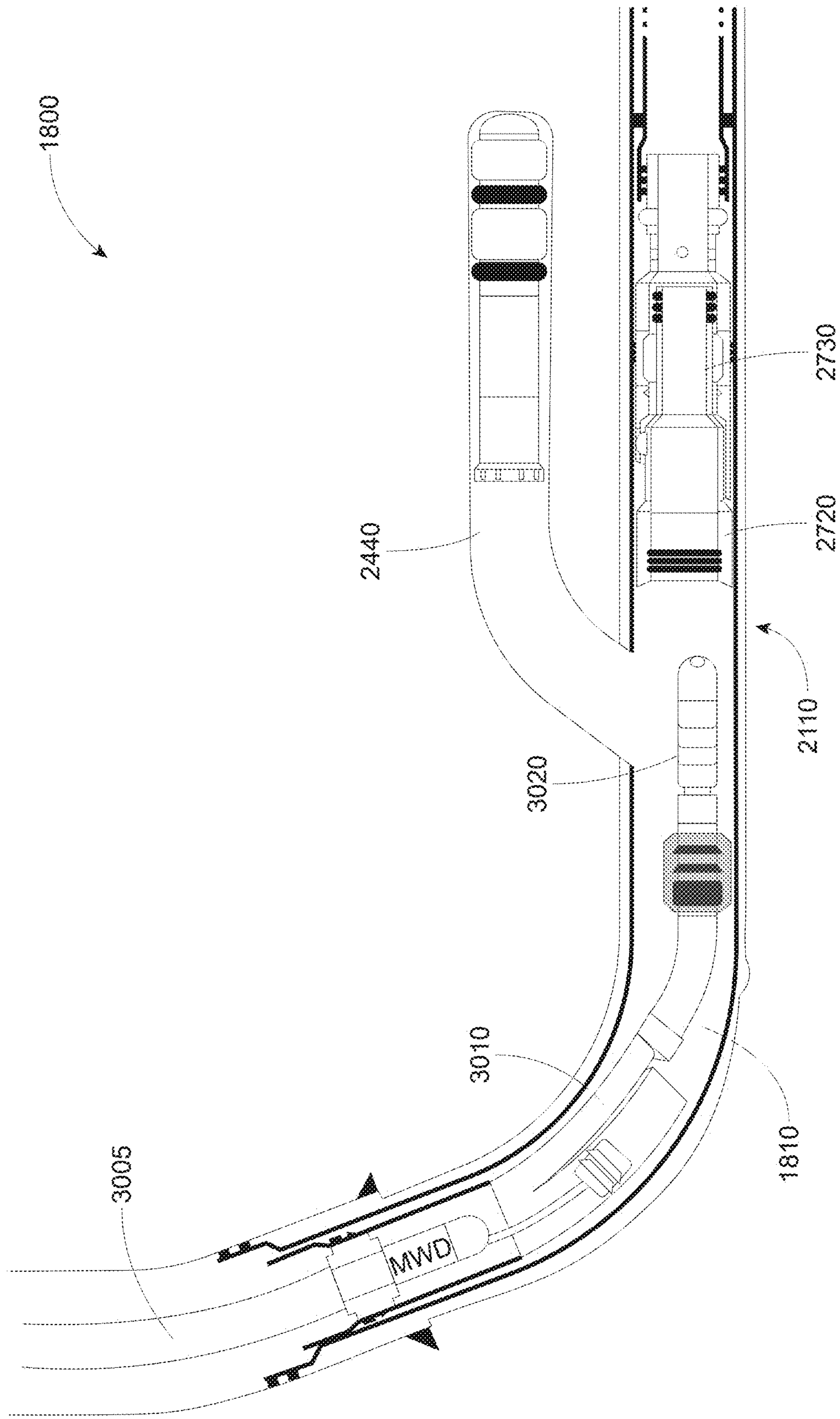

FIG. 30

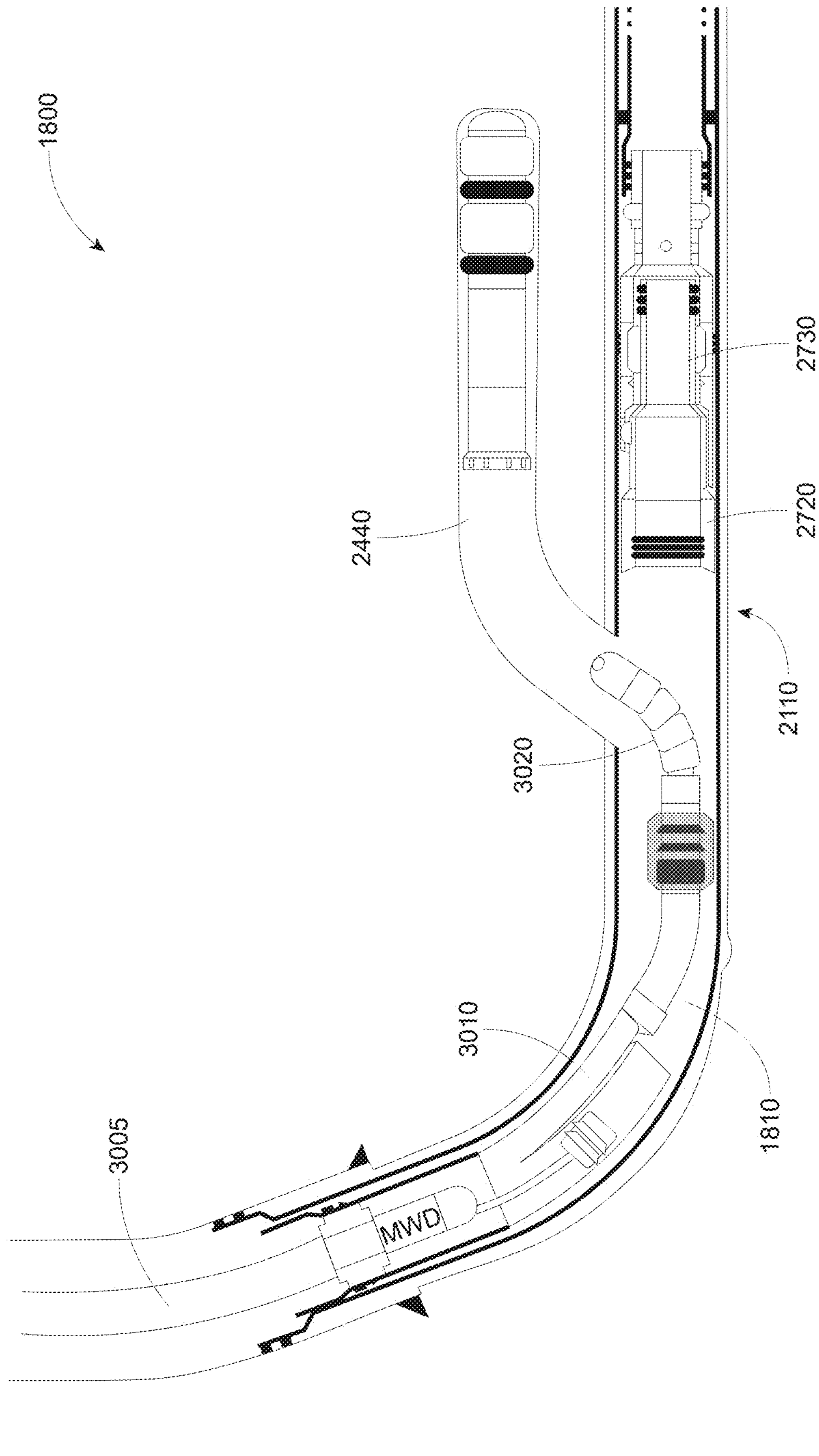

FIG. 31

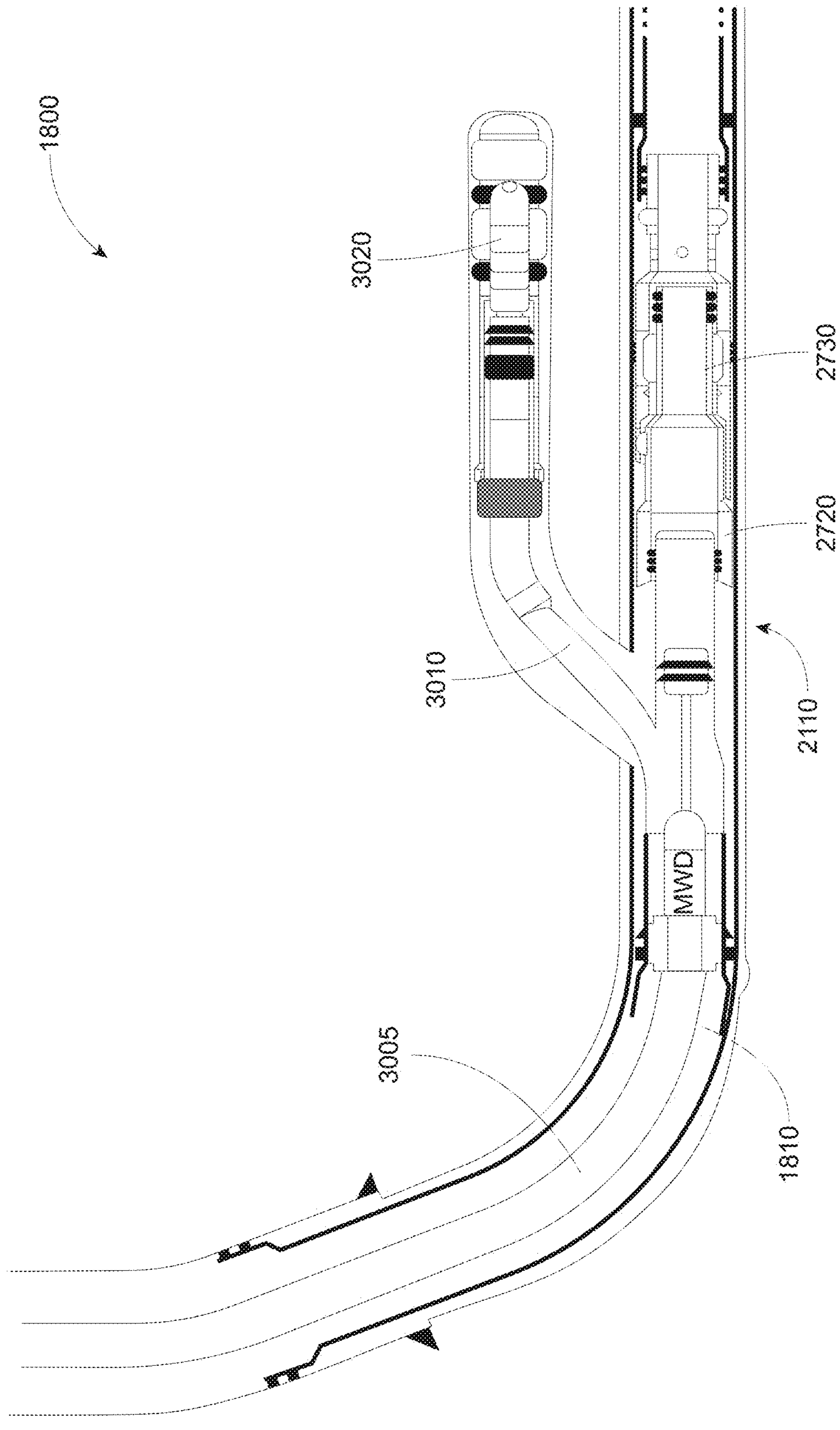

FIG. 32

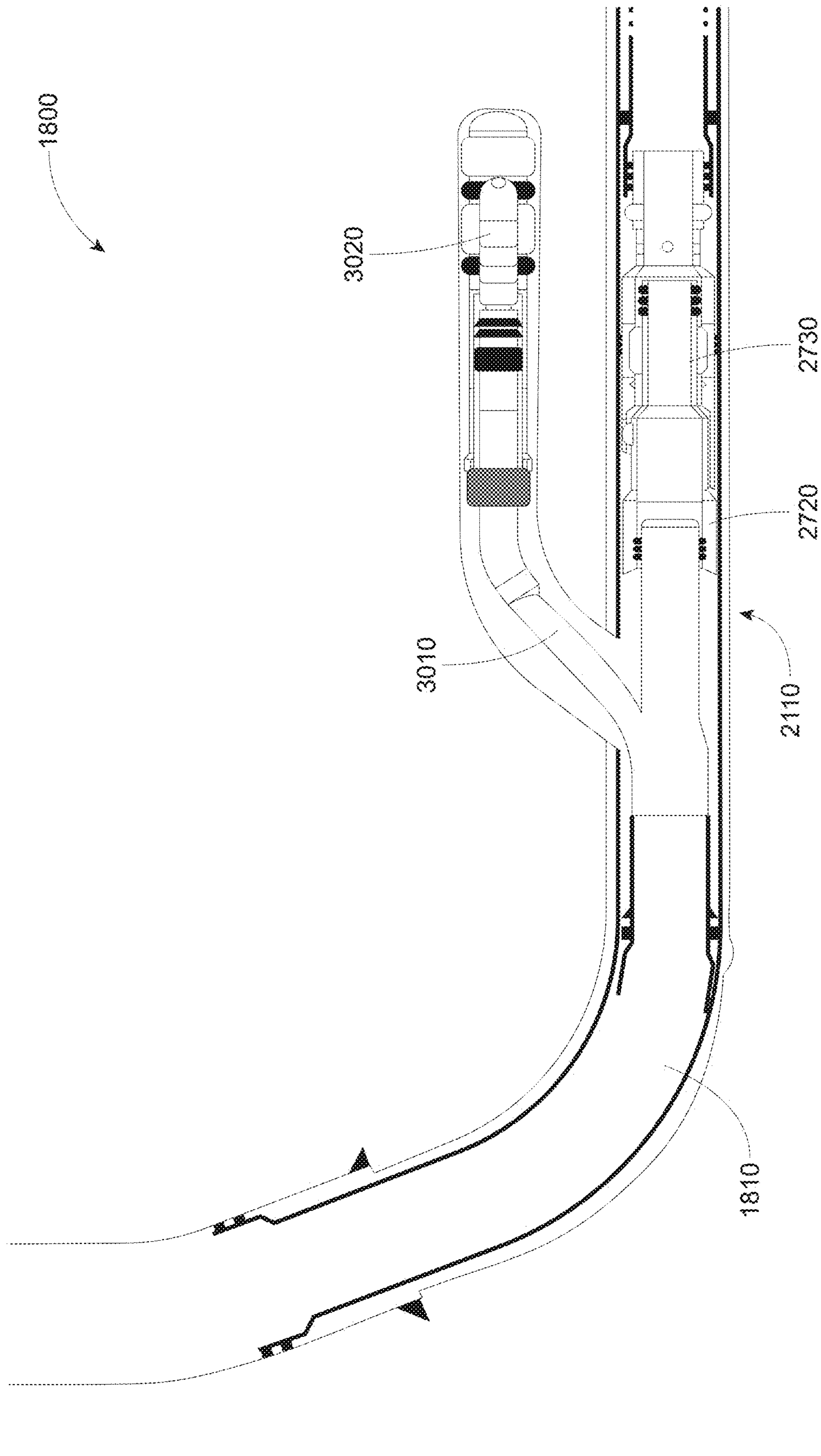

FIG. 33

WHIPSTOCK WITH DETACHABLE WHIPFACE AND SEALING CAPABILITIES FOR MULTILATERAL SYSTEMS

CROSS-REFERENCE TO RELATED APPLICATION

This application claims the benefit of U.S. Provisional Application Ser. No. 63/300,539, filed on Jan. 18, 2022, entitled "DETACHABLE WHIPSTOCK WITH SEALING CAPABILITIES FOR MULTILATERAL SYSTEMS," commonly assigned with this application and incorporated herein by reference in its entirety.

BACKGROUND

Multilateral wells include one or more lateral wellbores extending from a main wellbore. A lateral wellbore is a wellbore that is diverted from the main wellbore. A multilateral well may include one or more windows or casing exits to allow corresponding lateral wellbores to be formed. A milling assembly deflects upon a whipstock assembly to penetrate part of the casing joint and form the window or casing exit in the casing string, as well as to drill and complete the lateral wellbore. The milling assembly and the whipstock assembly are subsequently withdrawn from the wellbore. Thereafter, a deflector assembly is positioned at a junction between the main wellbore and lateral wellbore, wherein the deflector assembly is used to deflect other completion tools into the lateral wellbore.

BRIEF DESCRIPTION

Reference is now made to the following descriptions taken in conjunction with the accompanying drawings, in which:

FIG. **1** is a schematic view of a multilateral well according to one or more embodiments disclosed herein;

FIG. **2**A illustrates a lateral locating assembly designed and manufactured according to one or more embodiments of the disclosure, for example shown in a run-in-hole state;

FIG. **2**B illustrates the lateral locating assembly shown in FIG. **2**A in a deflected state;

FIGS. **3**A through **3**F illustrate the lateral locating assembly illustrated in FIG. **2**A shown in various positions transitioning from a first run-in-hole state to a final deflected state and then back to the first run-in-hole state;

FIG. **4** illustrates a lateral locating assembly designed and manufactured according to one or more alternate embodiments of the disclosure;

FIG. **5** illustrates another lateral locating assembly designed and manufactured according to one or more alternate embodiments of the disclosure;

FIG. **6** is a schematic view of a multilateral well according to one or more alternative embodiments disclosed herein;

FIGS. **7**A through **7**C illustrate schematic views of a hydraflex lateral locating assembly designed, manufactured and operated according to one or more embodiments of the disclosure in various different operational configurations;

FIGS. **8**A through **8**E illustrate sequential views of the hydraflex lateral locating assembly in various stages of a procedure for entering a lateral wellbore extending from a main wellbore;

FIGS. **9**A through **10**D illustrate are various different views of a whipstock designed, manufactured and/or operated according to one or more embodiments of the disclosure;

FIGS. **11**A through **11**E illustrate one embodiment of a detaching sequence for a whipstock designed, manufactured and/or operated according to one or more embodiments of the disclosure;

FIGS. **12**A through **12**C illustrate one embodiment of a multilateral junction including a mainbore leg and a lateral bore leg engaging with the lower sub and/or one or more seals of the whipstock of FIG. **11**E;

FIGS. **13**A through **13**D illustrate various different views (e.g., outside and partial cutaway perspective) of a lateral locating assembly designed, manufactured and/or operated according to one or more embodiments of the disclosure;

FIGS. **14**A through **14**H illustrate various cross-sectional views of another embodiment of a lateral locating assembly at various different deployment states;

FIGS. **15**A through **15**C illustrate various different operational views of a lateral locating assembly engaging with a lateral liner, as might occur when the lateral locating assembly has entered a lateral wellbore and is proceeding to engage with a lateral completion;

FIGS. **16**A through **16**F illustrate different schematic views of a lateral locating assembly traversing through a main wellbore and a lateral wellbore in accordance with one or more embodiments of the disclosure;

FIGS. **17**A through **17**D illustrate different operational views of a multilateral junction designed, manufactured and/or operated according to one or more embodiments of the disclosure; and

FIGS. **18** through **33** illustrate a method for forming, accessing, and completing a well system in accordance with one or more embodiments of the disclosure.

DETAILED DESCRIPTION

In the drawings and descriptions that follow, like parts are typically marked throughout the specification and drawings with the same reference numerals, respectively. The drawn figures are not necessarily to scale. Certain features of the disclosure may be shown exaggerated in scale or in somewhat schematic form and some details of certain elements may not be shown in the interest of clarity and conciseness. The present disclosure may be implemented in embodiments of different forms.

Specific embodiments are described in detail and are shown in the drawings, with the understanding that the present disclosure is to be considered an exemplification of the principles of the disclosure, and is not intended to limit the disclosure to that illustrated and described herein. It is to be fully recognized that the different teachings of the embodiments discussed herein may be employed separately or in any suitable combination to produce desired results. Unless otherwise specified, use of the terms "connect," "engage," "couple," "attach," or any other like term describing an interaction between elements is not meant to limit the interaction to direct interaction between the elements and may also include indirect interaction between the elements described. Unless otherwise specified, use of the terms "up," "upper," "upward," "uphole," "upstream," or other like terms shall be construed as generally away from the bottom, terminal end of a well; likewise, use of the terms "down," "lower," "downward," "downhole," "downstream," or other like terms shall be construed as generally toward the bottom, terminal end of a well, regardless of the wellbore orientation. Use of any one or more of the foregoing terms shall not be construed as denoting positions along a perfectly vertical axis. Unless otherwise specified, use of the term "subterranean formation" shall be construed as encompassing both areas below exposed earth and areas below earth covered by water, such as ocean or fresh water.

A subterranean formation containing oil and/or gas hydrocarbons may be referred to as a reservoir, in which a reservoir may be located on-shore or off-shore. Reservoirs are typically located in the range of a few hundred feet (shallow reservoirs) to tens of thousands of feet (ultra-deep reservoirs). To produce oil, gas, or other fluids from the reservoir, a well is drilled into a reservoir or adjacent to a reservoir.

A well can include, without limitation, an oil, gas, or water production well, or an injection well. As used herein, a "well" includes at least one wellbore having a wellbore wall. A wellbore can include vertical, inclined, and horizontal portions, and it can be straight, curved, or branched. As used herein, the term "wellbore" includes any cased, and any uncased (e.g., open-hole) portion of the wellbore. A near-wellbore region is the subterranean material and rock of the subterranean formation surrounding the wellbore. As used herein, a "well" also includes the near-wellbore region. The near-wellbore region is generally considered to be the region within approximately 100 feet of the wellbore. As used herein, "into a well" means and includes into any portion of the well, including into the wellbore or into the near-wellbore region via the wellbore.

While a main wellbore may in some instances be formed in a substantially vertical orientation relative to a surface of the well, and while the lateral wellbore may in some instances be formed in a substantially horizontal orientation relative to the surface of the well, reference herein to either the main wellbore or the lateral wellbore is not meant to imply any particular orientation, and the orientation of each of these wellbores may include portions that are vertical, non-vertical, horizontal or non-horizontal. Further, the term "uphole" refers to a direction that is towards the surface of the well, while the term "downhole" refers to a direction that is away from the surface of the well.

FIG. **1** is a schematic view of a well system **100** according to one or more embodiments disclosed herein. The well system **100** includes a platform **120** positioned over a subterranean formation **110** located below the earth's surface **115**. The platform **120**, in at least one embodiment, has a hoisting apparatus **125** and a derrick **130** for raising and lowering pipe strings, such as a tubing string **140**. Although a land-based oil and gas platform **120** is illustrated in FIG. **1**, the scope of this disclosure is not thereby limited, and thus could potentially apply to offshore applications. The teachings of this disclosure may also be applied to other land-based multilateral wells different from that illustrated.

As shown, a main wellbore **150** has been drilled through the various earth strata, including the subterranean formation **110**. The term "main" wellbore is used herein to designate a wellbore from which another wellbore is drilled. It is to be noted, however, that a main wellbore **150** does not necessarily extend directly to the earth's surface, but could instead be a branch of yet another wellbore. A casing string **160** may be at least partially cemented within the main wellbore **150**. The term "casing" is used herein to designate a tubular string used to line a wellbore. Casing may actually be of the type known to those skilled in the art as a "liner" and may be made of any material, such as steel or composite material and may be segmented or continuous, such as coiled tubing. The term "lateral" wellbore is used herein to designate a wellbore that is drilled outwardly from its intersection with another wellbore, such as a main wellbore. Moreover, a lateral wellbore may have another lateral wellbore drilled outwardly therefrom.

A lateral locating assembly **170** according to one or more embodiments of the present disclosure may be positioned at a location in the main wellbore **150**. Specifically, the lateral locating assembly **170** would be placed at a location in the main wellbore **150** where an exit window may be milled for access to a lateral wellbore **180**. Accordingly, the lateral locating assembly **170** may be used to support one or more tools accessing the lateral wellbore **180**. In some embodiments, the lateral locating assembly **170** may include an inner diameter running there through for fluid access, for example without needing support from a whipstock or traditional deflectors or deviation systems. In fact, the well system **100** of FIG. **1** may operate without any deflectors in one or more embodiments of the disclosure.

The lateral locating assembly **170**, in one or more embodiments, may include a housing and a piston positioned within the housing. A mandrel may extend from a distal end of the housing, and the mandrel may be configured to rotate and translate angularly in response to the piston moving from a first position to a second position. A bendable deflection tip may be coupled with a distal end of the mandrel, the deflection tip configured to rotate and angularly translate with the mandrel relative to the housing. When the lateral locating assembly **170** reaches the exit window for the lateral wellbore **180**, an axial force (e.g., via fluid pressure) may be applied to the piston to move the piston from the first position to the second position, thereby rotating the mandrel and deflection tip. An angled inner surface in a distal end of the housing may be configured to engage a ramp positioned on an outer surface of the mandrel such that as the mandrel and the deflection tip coupled thereto rotate, the mandrel and deflection tip may also translate angularly with respect to the housing and into the lateral wellbore **180**.

Turning now to FIGS. **2**A and **2**B, there is shown one embodiment of a lateral locating assembly **200** designed and manufactured according to one or more embodiments of the disclosure. The lateral locating assembly **200** is shown in FIG. **2**A in a run-in-hole state (e.g., straight position) and shown in FIG. **2**B in a deflected state (e.g., bent position). The lateral locating assembly **200**, in one embodiment, may include a housing **205**. Positioned within the housing **205** may be a piston **220**, the piston **220** configured to move from a first position as shown in FIG. **2**A to a second position as shown in FIG. **2**B. In some embodiments, a mandrel **225** may extend from a distal end of the housing **205**, the mandrel **225** configured to rotate and translate angularly in response to the piston **220** moving from the first position to the second position. In some embodiments, the mandrel **225** may rotate about 180 degrees relative to the housing **205**.

A deflection tip **230** (e.g., bendable deflection tip) may be coupled with a distal end of the mandrel **225** and configured to rotate and angularly translate with the mandrel **225** relative to the housing **205** as the piston **220** moves from the first position to the second position. The deflection tip **230** is illustrated in FIGS. **2**A and **2**B as a separate feature. Nevertheless, other embodiments may exist wherein the deflection tip and the mandrel **225** are a single feature. In certain embodiments, the deflection tip **230** is configured to rotate by about 180 degrees and angularly translate (e.g., bend) by an angle (θ) of at least about 5 degrees as the piston moves from the first position to the second position. In some other embodiments, the deflection tip **230** may be configured to rotate eccentrically by about 180 degrees and angularly translate (e.g., bend) by an angle (θ) of at least about 5 degrees.

In the illustrated embodiment, a rotating transmission sleeve **235** may be coupled between the piston **220** and the mandrel **225**. The rotating transmission sleeve **235** may include a helical channel **240**. The helical channel **240** may engage a protrusion **245** on the piston **220** such that the helical channel **240** may follow the protrusion **245** and rotate the rotating transmission sleeve **235** as the piston **220** moves from the first position to the second position. As the rotating transmission sleeve **235** rotates, the mandrel **225** and the deflection tip **230** may likewise rotate and angularly translate relative to the housing **205**.

In some embodiments, the housing **205** may include a piston housing **210** on a proximal end thereof and a separate eccentric housing **215**. The eccentric housing **215**, in one or more embodiments, may include an angled inner surface **218**.

In the illustrated embodiment a ramp **250** (e.g., eccentric ramp) may be coupled on an outer surface of the mandrel **225**. The ramp **250** may be configured to engage the angled inner surface **218** of the housing **205** as the mandrel **225** rotates, and thereby angularly translate the mandrel **225** relative to the housing **205**. In this embodiment, the piston **220** may be maintained in the first position by a spring **260** and as such the deflection tip **230** is maintained in a neutral, run-in-hole state (e.g., straight position). An axial (linear) force may be applied to the piston **220**, which may compress the spring **260** and thereby move the piston **220** from the first position shown in FIG. **2**A to the second position shown in FIG. **2**B (e.g., bent position).

When lateral intervention is no longer necessary, the lateral locating assembly **200** may in some embodiments be returned to the run-in-hole, or neutral, position shown in FIG. **2**A, wherein the piston **220** may be returned from the second bent position back to the first straight position. As such, the deflection tip **230** may be rotated and angularly translated from the deflected state shown in FIG. **2**B back to the run-in-hole position shown in FIG. **2**A. The lateral locating assembly **200** may then be retrieved uphole, or may be positioned at another location within the wellbore for access of another lateral wellbore portion. The lateral locating assembly **200** may accordingly provide access to at least one lateral wellbore without the need for other downhole tools, such as a deflector or other supporting tools, and thus, additional trips into the wellbore by a tubing string or downhole conveyance may not be required.

Turning now to FIGS. **3**A through **3**F, an example of the lateral locating assembly **200** is shown in various operational states and reference depths with respect to a window **300** to a lateral wellbore **310**. FIG. **3**A illustrates the lateral locating assembly **200** in a neutral, run-in-hole state, wherein the deflection tip **230** is in a straight non-deflected position. In the illustrated example, the reference depth of the deflection tip **230** with respect to the window **300** may be about 0 cm. FIG. **3**B illustrates the lateral locating assembly **200** in a deflected state wherein the deflection tip **230** has rotated and translated angularly into a bent deflected position, and beginning to deviate through the window **300** into the lateral wellbore **310**, in this example, at a reference depth of about 2 cm (0.756 in.) with respect to the window **300**. FIG. **3**C illustrates the lateral locating assembly **200** with the deflection tip **230** in a deflected position as the lateral locating assembly **200** deviates into the lateral wellbore **310** at a reference depth, in this example, of about 35.66 cm (1.17 ft.) through the window **300**. FIG. **3**D illustrates the lateral locating assembly **200** in a deflected position partially deviated into the lateral wellbore **310** at a reference depth of about 60.05 cm (1.97 ft.) with respect to the window **300**. FIG. **3**E illustrates the lateral locating assembly **200** in a deflected position with the deflection tip **230** substantially deviated (deviated between about 55-100%) into the lateral wellbore **310** at a reference depth of about 155.45 cm (5.10 ft.) with respect to the window **300**. FIG. **3**F illustrates the lateral locating assembly **200** back in a neutral, run-in-hole state, wherein the deflection tip **230** is again in a straight non-deflected position. The lateral wellbore **310** may now be accessed for fluid passage and/or accessed by downhole tools through the lateral locating assembly **200**.

Turning now to FIG. **4**, there is shown another embodiment of a lateral locating assembly **400** according to principles of the disclosure. The lateral locating assembly **400** is similar in many respects to the lateral locating assembly **200** of FIGS. **2**A-**2**B. Accordingly, like reference numbers have been used to reference similar, if not identical, features. The lateral locating assembly **400** differs, for the most part, from the lateral locating assembly **200**, in that the lateral locating assembly **400** includes a fluid nozzle assembly **475** positioned within the housing **205** at an uphole end of the piston **220**. In some embodiments, the fluid nozzle assembly **475** may increase pressure on the piston **220**, in order to urge the piston **220** from the first position to the second position. The fluid nozzle assembly **475** may activate the piston **220** due to differential pressure in the wellbore. In some embodiments, the fluid nozzle assembly **475** may be needed when more force is required to urge the piston **220** from the first position (e.g., when there may be a smaller cross section in the wellbore over which fluid flow is available). In addition, various sizes of nozzles may be used in the fluid nozzle assembly **475** according to different environments and configurations in which the lateral locating assembly **400** may be placed.

Turning now to FIG. **5**, there is shown another embodiment of a lateral locating assembly **500** according to principles of the disclosure. The lateral locating assembly **500** is similar in many respects to the lateral locating assembly **200** of FIGS. **2**A-**2**B. Accordingly, like reference numbers have been used to reference similar, if not identical, features. The lateral locating assembly **500** differs, for the most part, from the lateral locating assembly **200**, in that the lateral locating assembly **500** includes a hydraulic power unit **580** coupled uphole of the piston **220**. The hydraulic power unit **580** may be configured to mechanically move the piston **220** from the first position to the second position. In some embodiments, the hydraulic power unit **580** may be programmable to mechanically move the piston **220** from the first position to the second position after one or more pressure cycles thereon. The programming of hydraulic power unit **580** may depend on signature pressure amounts or cycles determined according to anticipated environments and configurations in which the lateral locating assembly **500** may be placed. The hydraulic power unit **580**, in some embodiments, may be actuated remotely using applied surface pressure. In other embodiments, the hydraulic power unit **580** may be actuated by hydrostatic pressure and may include actuation by a timer.

Turning now to FIG. **6**, there is shown a schematic view of a multilateral well **600** according to one or more alternative embodiments disclosed herein. The multilateral well **600** is similar in many respects to the multilateral well **100** of FIG. **1**. Accordingly, like reference numbers have been used to reference similar, if not identical, features. The multilateral well **600** differs, for the most part, from the multilateral well **100**, in that the multilateral well **600** employs a hydraflex lateral locating assembly **670**, as discussed further below.

Turning now to FIG. **7**A there is shown a schematic view of a hydraflex lateral locating assembly **700** designed, manufactured and operated according to one or more embodiments of the disclosure in a straight position. The hydraflex lateral locating assembly **700** includes an upper housing **705** and a lower housing **710**, coupled to one another along a tool axis A**1**. The upper and lower housings **705**, **710** are rotationally coupled to one another to permit rotational movement therebetween about the tool axis A**1**, and together define an orientation sub **715**. A rotational driver **720**, such as a hydraulic motor, is disposed within the upper housing **705** of the orientation sub, and is operable to selectively induce rotational motion of the lower housing **710** with respect to the upper housing **705** in either direction, e.g., clockwise and counter-clockwise directions. The rotational driver **720** may include hydraulic, pneumatic, mechanical or other mechanisms recognized in the art. A first actuator, controller or orientation actuator **725** is operably coupled to the rotational driver **720** to permit an operator to selectively operate the rotational driver **720**. The first actuator **725** may be disposed at the surface location (e.g., surface **115** illustrated in FIG. **6**) or at a downhole location. The upper housing **705** defines a connector **730** such as threads, latches, etc., for coupling the hydraflex lateral locating assembly **700** to the lower end of a tubing string (e.g., the tubing string **140** illustrated in FIG. **6**). The connector **730** may fixedly couple the upper housing **705** to the tubing string, and thus, in some embodiments, the rotational driver **720** may selectively rotate the lower housing **710** with respect to the tubing string.

The upper housing **705** may also support a sensor package **735** therein. For tool strings equipped with real-time communication capabilities, the sensor package **735** provides an operator with real-time information regarding position and configuration of the hydraflex lateral locating assembly **700**. For example, the sensor package **735** may include tool face sensors, inclination sensors, gamma sensors, casing collar locators (CCL) or cameras, which can provide additional verification of a successful entry into a lateral wellbore as described below. In some embodiments, the sensor package **735** is disposed in a separate sensor sub coupled to the upper housing **705**.

A kick-over sub **740** is coupled to a lower end of the lower housing **710**. In the embodiment illustrated in FIG. **7**A, the kick-over sub **740** includes a segmented tubular section **745** and a bottom hole assembly BHA **750** including a fluid nozzle **755**. The segmented tubular section **745** includes a plurality of pivotally coupled sections **760**, which permit the hydraflex lateral locating assembly **700** to be moved to a bent articulated position wherein BHA **750** is obliquely arranged with respect to the tool axis A**1** (see FIG. **7**B). Sections **760** may simply be added or removed from a segmented tubular section **745** as the kick-over sub **740** is manufactured to adjust the angle of the bend to suit different well geometries or BHA **750** lengths. In other embodiments (not shown) the BHA **750** may include any tool or structure useful in completing or servicing the lateral wellbore or vertical main wellbore. Also, in other embodiments, the kick-over sub **740** may include any structure operable to move the BHA **750** between aligned (e.g., straight) and oblique (e.g., bent) arrangements with respect to the tool axis A**1** (see FIG. **7**B). For example, the kick-over sub may include an indexed, knuckle-type kick-over sub operable to move the BHA **750** to discrete articulated and incremental rotational positions by cycling a fluid pressure within the hydraflex lateral locating assembly **700**.

A fluid passageway **765** extends through the hydraflex lateral locating assembly **700**, fluidly coupling the nozzle **755** to the tubular string. The hydraflex lateral locating assembly **700** may maintain the straight configuration when fluid **770** is passed through the fluid passageway **765** at a rate less than a predetermined threshold. A second actuator or kick-over actuator **775** is operatively coupled to the fluid passageway for controlling a rate of fluid **770** flowing through the fluid passageway **765**. In some embodiments, the second actuator **775** may include a pump (not shown) at the surface (e.g., earth surface **115** as shown in FIG. **6**).

Turning now to FIG. **7**B there is shown a schematic view of a hydraflex lateral locating assembly **700** designed, manufactured and operated according to one or more embodiments of the disclosure in an articulated configuration induced by operating the kick-over actuator **775**. For example, the kick-over actuator **775** may have been operated to increase the flow of fluid **770** to a flowrate greater than the predetermined threshold. With the increased flowrate, a pressure differential across the nozzle **755** may be sufficient to move the sections **760** to pivot relative to one another, thereby bending the segmented tubular section **745** and moving the nozzle **755** to the oblique orientation with respect to the tool axis A**1**. The kick-over actuator **775** may be operated without rotating the nozzle **755** with respect to the tool axis A**1** or the tubular string **30** and longitudinal axis.

Turning now to FIG. **7**C there is shown a schematic view of a hydraflex lateral locating assembly **700** designed, manufactured and operated according to one or more embodiments of the disclosure in an oriented configuration induced by operating the orientation actuator **725**. The orientation actuator **725** may be operated to send a control signal to the rotational driver **720** to thereby rotate the lower housing **710** with respect to the upper housing **705** of the orientation sub **715**. Since the segmented tubular section **745** and BHA **750** are coupled to the lower housing **710**, the BHA **750** is rotated to the illustrated position while the hydraflex lateral locating assembly **700** maintains the articulated position. In the oriented configuration of FIG. **7**C, the BHA **750** is rotated generally up to 180 degrees in either direction (e.g., clockwise or counterclockwise) from an un-oriented configuration of FIG. **7**C. In other embodiments, the oriented configuration may require a distinct degree of rotation of the lower housing **710** that is less than 180 degrees to align the BHA with the lateral wellbore **14** in any rotational position.

Although FIGS. **7**A through **7**C illustrate the end of the BHA **750** as equipped with a nozzle tool **755**, in other embodiments, a BHA may be provided equipped with alternate subterranean tools without departing from the scope of the disclosures. For example, a BHA may be provided with tools such as milling tools, shifting tools, venturi subs, or any number of other downhole components as needed to complete various operational objectives.

FIGS. **8**A through **8**E are sequential views of the hydraflex lateral locating assembly **700** in various stages of a procedure for entering a lateral wellbore **820** extending from a main wellbore **810**. Initially, the hydraflex lateral locating assembly **700** is lowered or run into the main wellbore **810** on tubular string **830** or other conveyance. A rig may be employed to lower the hydraflex lateral locating assembly **700** into the main wellbore **810**, and as the hydraflex lateral locating assembly **700** is lowered, the sensor package **735** may operate to count the casing collars **840** encountered. As the hydraflex lateral locating assembly **700** approaches the depth of the lateral wellbore **820** and an expected number of casing collars **840** is encountered, the hydraflex lateral locating assembly **700** may be held at a depth above the lateral wellbore **820**. In other embodiments, the sensor package **735** or other portions of the tubular string **830** may include other tools for of depth correlation, such as an in-line camera, gamma sensor, and/or caliper. Other tools such as an in-line camera may provide an indication of depth and tool face to an operator at the surface.

As illustrated in FIG. **8**B, thereafter the hydraflex lateral locating assembly **700** may be rotationally oriented. The sensor package **735** may provide an initial tool face orientation of BHA **750**, and the difference between the initial tool face and the circumferential position of the lateral wellbore **820** is determined. The orientation actuator **725** (FIG. **7**C) may be employed to command the rotational driver **720** to rotate the lower housing **710** by the exact difference between the initial tool face and the circumferential position of the lateral wellbore **820**. The lower housing **710** may be rotated in a clockwise or counter-clockwise direction, whichever is shorter, with respect to the upper housing **705** of the orientation sub **715**. The BHA **750** may thereby be rotationally oriented without pivoting the BHA **750**.

Next, as illustrated in FIG. **8**C, the hydraflex lateral locating assembly **700** tool is moved to the bent articulated position to pivot the BHA **750**. The kick-over actuator **775** (FIG. **7**B) may be employed to increase the flow rate of fluid **770** through the hydraflex lateral locating assembly **700** above the necessary threshold to bend the kick-over sub **740** (FIG. **7**B). In some embodiments, the amount the flow rate is increased above the threshold will correspond to an increased amount the BHA **750** pivots from the tool axis A**1**. The rotational orientation of the BHA is maintained as the kick-over actuator **775** is activated to pivot the BHA **750** toward the lateral wellbore **820**. Since the orientation sub **715** and kick-over sub **740** are independently activated, the processes shown in FIGS. **8**B and **8**C may be reversed.

Next, as illustrated in FIG. **8**D, the hydraflex lateral locating assembly **700** is lowered further in the main wellbore **810** such that the BHA **750** passes through the window **850**. If the BHA **750** is properly oriented and pivoted, the hydraflex lateral locating assembly **700** will enter the lateral wellbore **820** in the articulated configuration.

As illustrated in FIG. **8**E, an inclination sensor within the sensor package **735** may verify that an expected inclination of the sensor package **735** has been achieved to verify a successful entry into the lateral wellbore **820**. Alternatively, or additionally, some embodiments may utilize a gamma sensor in the sensor package **735** to verify lateral entry based on identifying an expected lithology, for example. The sensor package **735** may communicate a signal indicative of a successful entry to the surface to an operator. Next, the kick-over actuator **775** (FIG. **7**B) may optionally be again actuated to return the hydraflex lateral locating assembly **700** to the straight configuration illustrated in FIG. **8**E. In the straight configuration, friction between the hydraflex lateral locating assembly **700** and the lateral wellbore **820** may be reduced as the hydraflex lateral locating assembly **700** is further advanced into the lateral wellbore **820** to carry out a wellbore operation, The hydraflex lateral locating assembly **700** may be withdrawn from the lateral wellbore **820**, and the procedure may be repeated for additional lateral wellbores **820** branching from the main wellbore **810**.

The present disclosure proposes the installation of a Level 5 multilateral junction without the use/installation of a deflector in the mainbore. The present disclosure, in at least one embodiment, includes a whipstock having a detachable whipface. The whipstock having the detachable whipface will be able to save the operator **1** trip down hole (~12 hours) and still provide the conditions required to install a level 5 junction. Moreover, this will all be achieved using the current designs for the XLS whipface and deflector seal sub; which is a time/cost saving for the company.

The detachable whipstock of the present disclosure (e.g., with sealing capabilities) will be able to provide, depending on the embodiment, many advantages over existing technologies. First, the detachable whipstock provides a whipface for milling of a multilateral window. And may be installed on a shear bolted mill. Additionally, the detachable whipstock provides a seal sub (e.g., T-seals for junction installation), which may be installed with either FlexRite latch coupling or ReFlexRite latch BHA (using VF anchor), among others. Moreover, the detachable whipstock may provide a detachable sub that is shear pinned (e.g., to support axial force) and able to hold torque due to locking teeth. The sub will allow the whipface to be detached from the seal sub. Additionally, the detachable whipstock may provide an inner sleeve connected to the whipface that will protect the seals in the BHA while milling and drilling occurs. When the whipface is detached and pulled out of hole (POOH), the inner protective sleeve exposes the seals and provides the conditions to land a MIC junction. Moreover, the detachable whipstock may provide filters inside the protective inner sleeve that will catch milling and drilling debris. When the whipface is detached and POOH, the debris that is caught is retrieved. Additionally, the detachable whipstock allows for the whipface and protective sleeve to be detached using current running tools. In yet another example, the detachable whipstock provides the option to retrieve the seal sub BHA back to surface if required. The combinations of one or more of these features allows for the installation of a multilateral junction with one less run, which is not possible with existing technologies.

The present disclosure also allows for the junction to be run with an open hole stinger integrated with a lateral locating assembly (e.g., hydraulic bending tool such as a hydraflex) that will provide access to the lateral when required. In at least one embodiment, the lateral locating assembly includes a sliding sleeve, which will open when installed in the lateral to allow oil production. The lateral locating assembly of the present disclosure will be able to provide, depending on the embodiment, many advantages over existing technologies. For example, the lateral locating assembly may provide a bending assembly that is hydraulically triggered to access a lateral bore without the use of a deflector. The hydraflex offers the possibility to customize the bending angle by adjusting the number of modules (e.g., 3 degrees each), to perfectly match well requirements. As it is activated by pressure, a sub with small orifice will be added below to create required pressure drop when pumping. The lateral locating assembly may also provide a sliding sleeve that is in the closed position while RIH to allow the hydraflex to function properly. The sliding sleeve will open when installed in the lateral inside the lateral liner to allow oil production. The lateral locating assembly may additionally provide a shrouded open hole stinger with a swell packer and swab cups to seal in a 6.00" polished bore receptacle (PBR) in the lateral liner. In yet another embodiment, the lateral locating assembly may provide an interaction between the OHS and the sliding sleeve that will allow them to work in conjunction. When the shroud is fixed with shear screws into the OHS, the sliding sleeve will be closed. When the screws in the shroud are sheared the sliding sleeve will open and will stay open (e.g., by way of a snap ring or other retaining mechanism). The combination of one or more of these features allows for the installation of a multilateral junction with one less run, which is not present in other existing technologies.

Turning to FIGS. **9**A through **10**D, illustrated are various different views of a whipstock **900** designed, manufactured and/or operated according to one or more embodiments of the disclosure. FIGS. **9**A through **9**D illustrated outside views of the whipstock **900**, whereas FIGS. **10**A through **10**D illustrate cross-sectional views of the whipstock **900**. The whipstock **900**, in one or more embodiments, includes a detachable whipface with sealing capabilities. For example, in at least one embodiment, the whipstock **900** includes a bottom hole assembly (BHA) that will allow: 1) the creation of a lateral wellbore; 2) the ability to drop screens in the lateral wellbore; and 3) a sequence to detach the whipface and expose a seal sub to install a multilateral junction.

The whipstock **900**, in one or more embodiments, includes a whipface **910** having an angled casing string exit surface **915**. The whipstock **900**, according to at least one embodiment, further includes a sub **950** detachably coupled to the whipface **910**, as well as a bottom hole assembly **980** fixedly coupled to the sub **950**. The sub **950**, in one or more embodiments, is a lower sub **960**, and the whipstock **900** further includes an upper sub **920** fixedly coupled to the whipface **915** between the whipface **915** and the lower sub **960**. In at least one embodiment, one or more shear features **925** detachably couple the whipface **910** and upper sub **920** to the lower sub **960**. Any number and type of shear features **925** may be used and remain within the scope of the disclosure.

In at least one embodiment, the whipstock **900** further includes a plurality of members **970** and member profiles **930** in the lower sub **960** and upper sub **920**. In one or more embodiments, the members **970** and member profiles **930** are teeth and grooves configured to cooperate to rotationally fix the lower sub **960** and the upper sub **920**, and thus take any rotational stress from the shear features **925**. Many different configurations for the members **970** and member profiles **930** may be used and remain within the scope of the disclosure.

In at least one embodiment, the upper sub **920** includes a tubular **940** that extends within the lower sub **920** and at least a portion of the bottom hole assembly **980**. The tubular **940**, in at least one embodiment, may have one or more debris collection devices **942** located therein. For instance, in at least one embodiment, the tubular **940** has a first course debris filter **942*a*** located within the tubular **940** and a second fine debris filter **942*b*** located within the tubular **940** downhole of the first course debris filter **942*a***. In yet another embodiment, the debris collection devices could be a magnet, scraper, etc. and remain within the scope of the disclosure. Other configurations for the number of debris collection devices **942**, type of debris collection devices **942** and relative locations for the debris collection devices **942** may be used and remain within the scope of the disclosure.

The bottom hole assembly **980**, in accordance with one embodiment of the disclosure, includes one or more seals **985** positioned along an inner surface thereof. The one or more seals **985**, in at least one embodiment, are protected by the tubular **940** of the upper sub **920** when the whipface **910** and upper sub **920** are engaged with the lower sub **960**, but will be exposed to other features (e.g., a mainbore leg of a multilateral junction) when the whipface **910** and upper sub **920** are disengaged from the lower sub **960**. In at least one embodiment, the one or more seals **985** are T-seals that form at least a portion of a seal sub.

The bottom hole assembly **980**, in one or more embodiments, may additionally include an alignment key **990** located along an outer surface thereof. The alignment key **990**, in at least one embodiment, may be configured to engage with a muleshoe of a related feature to rotationally position the whipface **910** within a casing string of a wellbore. The bottom hole assembly **980**, in one or more other embodiments, may additionally include one or more second seals **992** located along the outer surface thereof proximate a downhole end thereof, the one or more second seals **992** (e.g., V-pack seals) configured to engage and seal with a mainbore completion (e.g., not shown). The bottom hole assembly **980**, in yet another embodiment, may further include an anchor **994** (e.g., latch for a multilateral anchor) positioned between the alignment key **990** and the one or more second seals **992**, the anchor **994** configured to laterally fix the bottom hole assembly **980** relative to the mainbore completion.

Turning to FIGS. **11**A through **11**E, illustrated is one embodiment of a detaching sequence for a whipstock **1100** designed, manufactured and/or operated according to one or more embodiments of the disclosure. In the given embodiment, the whipstock **1100** is substantially similar to the whipstock **900** disclosed above. Accordingly, like reference numbers have been used to indicate similar, if not identical, features.

FIG. **11**A illustrates the installation of the whipstock **1100**. FIG. **11**B illustrates the engagement of a running tool **1110** with the whipface **910** and/or upper sub **920**. Accordingly, the whipface **910** and upper sub **920** are ready to be detached. FIG. **11**C illustrates the shearing of the shear features **925** (e.g., with a straight pull of the running tool **1110**). Accordingly, the whipface **910** and upper sub **920** are detached at this moment. FIG. **11**D illustrates as the whipface **910** and the upper sub **920** continue to be pulled out of hole. Accordingly, any debris trapped within the tubular **940** may be recovered. At this stage, the one or more seals **985** remain protected by the tubular **940**. FIG. **11**E illustrates that the lower sub **960** and the one or more seals **985** remain in the mainbore, for example with an angled shoulder **1120** to allow for easy entry of another downhole tool (e.g., mainbore leg of a multilateral junction). The angled shoulder **1120**, in at least one embodiment, may be angled by 10, 15, 30, 45 or more degrees). Furthermore, in at least one embodiment the remaining lower sub **960**, as well as all remaining portions of the whipstock **1100**, is entirely free of an angled casing string exit surface.

Turning to FIGS. **12**A through **12**C, illustrated is one embodiment of a multilateral junction **1200** including a mainbore leg **1210** and a lateral bore leg **1220** engaging with the lower sub **960** and/or one or more seals **985** of the whipstock **1100** of FIG. **11**E. FIG. **12**A illustrates that the mainbore leg **1210** of the multilateral junction **1200** is just about to enter the lower sub **960**. FIG. **12**B illustrates as the mainbore leg **1210** just begins to engage with the one or more seals **985**. FIG. **12**C illustrates as the mainbore leg **1210** is fully engaged with the lower sub **960**, and thus the one or more seals **985** are fully engaged.

Turning to FIGS. **13**A through **13**D, illustrated are various different views (e.g., outside and partial cutaway perspective) of a lateral locating assembly **1300** designed, manufactured and/or operated according to one or more embodiments of the disclosure. FIGS. **13**A and **13**B illustrate the lateral locating assembly **1300** in a run-in-hole position, whereas FIGS. **13**C and **13**D illustrate the lateral locating assembly **1300** in a bent position.

The lateral locating assembly **1300**, in at least one embodiment, includes a tubular **1310**. The tubular **1310**, in at least one embodiment, is coupled to a fluid pressure source (e.g., not shown). The tubular **1310**, in one or more embodiments, may have a length (L). The length (L) may be chosen and/or tailored to allow the lateral locating assembly **1300** to enter and extend within a lateral wellbore for a great amount of distance (e.g., before a sliding sleeve of the lateral locating assembly encounters a lateral liner thereof). In at least one embodiment, the length (L) may be at least 10 m, 20 m, 30 m, 50 m, 100 m or more, depending on the design of the lateral locating assembly **1300**.

The lateral locating assembly **1300**, in at least one other embodiment, includes a bendable deflection tip **1340** coupled to the tubular **1310**. In at least one embodiment, the bendable deflection tip **1340** is configured to move between a straight position (e.g., as shown in FIGS. **13**A and **13**B) and a bent position (e.g., as shown in FIGS. **13**C and **13**D) upon the application of fluid pressure thereto. The bendable deflection tip **1340**, and the movement thereto, in one or more embodiments may track that shown and discussed above with regard to FIGS. **1** through **5** and/or FIGS. **6** through **8**E, among other possible configurations. Nevertheless, the embodiment of FIGS. **13**A through **13**D are more similar to the lateral locating assembly of FIGS. **6** through **8**E.

In at least one embodiment, the lateral locating assembly **1300** includes one or more production ports **1350** coupling an interior of the tubular **1310** and an exterior of the tubular **1310**. The one or more production ports **1350**, in contrast to existing lateral locating assemblies, provide a fluid path for production fluid to enter and/or exit the lateral locating assembly **1300** for passageway between a surface of the wellbore and a subterranean formation.

In one or more embodiments, the lateral locating assembly **1300** includes a sliding sleeve **1360** positioned about the one or more production ports **1350**, the sliding sleeve **1360** configured to seal the one or more production ports **1350** when in a first position and expose the one or more production ports **1350** when in a second position. Accordingly, the sliding sleeve **1360** may be moved to the second position at a time when it is necessary or desirable for the production fluid to enter the lateral locating assembly **1300**.

In one or more embodiments, the lateral locating assembly **1300** additionally includes a shroud **1380** positioned about the tubular **1310** and removably coupled to the sliding sleeve **1360**. For example, the shroud **1380** could be sized such that it may enter a lateral wellbore and remain fixed in the run-in-hole position, but it is too large to enter the lateral liner. Thus, when the lateral locating assembly **1300**, and more particularly the shroud **1380**, encounters the lateral liner, the shroud **1380** remains fixed in location while other features of the lateral locating assembly **1300** may continue downhole. In one or more embodiments, it is this mechanism that shifts the sliding sleeve **1360** from the first position to the second position. Moreover, the lateral locating assembly **1300** may additionally include one or more shear features **1381** releasably coupled to the shroud **1380** to hold the sliding sleeve **1360** in the first position until the shroud **1380** encounters the lateral liner.

The lateral locating assembly **1300**, in one or more embodiments, may further include a packer **1390** coupled to the tubular **1310** uphole of the bendable deflection tip **1340**. In at least one embodiment, the packer **1390** is a swell packer protected by the shroud **1380** when the sliding sleeve **1360** is in the first position. The lateral locating assembly **1300**, in at least one embodiment, may further include one or more swab cups **1392** protected by the shroud **1380** when the sliding sleeve **1360** is in the first position, the one or more swab cups **1392** configured to provide a seal until the swell packer fully sets (e.g., once the lateral locating assembly **1300** is properly placed within the lateral wellbore, and ideally coupled to the lateral completion).

Turning to FIGS. **14**A through **14**H, illustrated are various cross-sectional views of another embodiment of a lateral locating assembly **1400** at various different deployment states. The lateral locating assembly **1400** is similar in many respects to the lateral locating assembly **1300**. Accordingly, like reference numbers have been used to indicate similar, if not identical, features. The lateral locating assembly **1400**, in one or more embodiments, also includes one or more no go blades **1410** coupled to a tip of the bendable deflection tip **1340**, the one or more no go blades **1410** configured to prevent the bendable deflection tip from accessing a main wellbore completion.

In one or more embodiments, the sliding sleeve **1360** includes a collet **1462**, the collet **1462** fixing the sliding sleeve **1360** to the shroud **1380** when the sliding sleeve **1360** is in the first position and releasing the sliding sleeve **1360** from the shroud **1380** when the sliding sleeve **1360** is in the second position. Further to this one embodiment, the shroud **1380** may include a first collet groove **1482** configured to engage the collet **1462** in an expanded state to fix the sliding sleeve **1360** to the shroud **1380** when the sliding sleeve **1360** is in the first position. Similarly, the tubular **1310** may include a second collet groove **1412** configured to accept the collet **1462** in a collapsed state to release the sliding sleeve **1360** from the shroud **1380** when the sliding sleeve **1360** is in the second position. In one or more embodiments, such as shown, the lateral locating assembly **1400** may additionally include a snap ring **1464** and snap ring groove **1414** located in ones of the tubular **1310** and the sliding sleeve **1360**, the snap ring **1464** configured to engage with the snap ring groove **1414** when the sliding sleeve **1360** is in the second position to fix the sliding sleeve **1360** in the second position.

FIGS. **14**A and **14**B illustrate the lateral locating assembly **1400** in the run-in-hole position, and thus the bendable deflection tip **1340** is in the straight position and the sliding sleeve **1360** is in the closed position. FIGS. **14**C and **14**D illustrate the lateral locating assembly **1400** after the bendable deflection tip **1340** is in the bent position, and the sliding sleeve **1360** remains in the closed position. FIGS. **14**E and **14**F illustrate the lateral locating assembly **1400** after the bendable deflection tip **1340** has returned to the straight position, and the shroud **1380** and sliding sleeve **1360** have slid to expose the one or more production ports **1350**. FIGS. **14**G and **14**H illustrate the lateral locating assembly **1400** after the shroud **1380** has released from the sliding sleeve **1360**.

FIGS. **15**A through **15**C illustrate various different operational views of a lateral locating assembly **1500** engaging with a lateral liner **1550**, as might occur when the lateral locating assembly **1500** has entered a lateral wellbore and is proceeding to engage with a lateral completion. The lateral locating assembly **1500** is similar in many respects to the lateral locating assembly **1300** discussed above. Accordingly, like reference numbers have been used to indicate similar, if not identical, features.

FIG. **15**A illustrates the lateral locating assembly **1500** as the shroud **1380** is just engaging with the lateral liner **1550**. Accordingly, the shroud **1380** is still releasably fixed with the sliding sleeve **1360**, and furthermore the sliding sleeve **1360** is in the first position sealing the one or more production ports **1350**. FIG. **15**B illustrates the lateral locating assembly **1500** as the shroud **1380** can no longer proceed downhole, and the sliding sleeve **1360** has slid to the second position exposing the one or more production ports **1350**. At this point, however, the shroud **1380** is still releasably fixed with the sliding sleeve **1360**. FIG. **15**C illustrates the lateral locating assembly **1500** as the sliding sleeve **1360** has released from the shroud **1380**, and furthermore that remaining features of the lateral locating assembly **1500** has continued downhole.

Turning to FIGS. **16**A through **16**F, illustrated are different schematic views of a lateral locating assembly **1600** traversing through a main wellbore **1650** and a lateral wellbore **1670** in accordance with one or more embodiments of the disclosure. The lateral locating assembly **1600** is similar in many respects to the lateral locating assembly **1300** discussed above. Accordingly, like reference numbers have been used to indicate similar, if not identical, features.

With initial reference to FIG. **16**A, the lateral locating assembly **1600** is located within the main wellbore **1650**, and for example approaching a whipstock **1610** (e.g., similar to the detachable whipstock discussed above with regard to FIG. **11**E). At this stage, the bendable deflection tip **1340** of the lateral locating assembly **1600** is in the straight position, and is located at an intersection between the main wellbore **1650** and the lateral wellbore **1670**.

Turning to FIG. **16**B, the lateral locating assembly **1600** has been activated (e.g., fluid pressure applied thereto), and thus the bendable deflection tip **1340** of the lateral locating assembly **1600** is now in the bent position. For example, at this point the bendable deflection tip **1340** of the lateral locating assembly **1600** has entered the lateral wellbore **1670**, and specifically entered the lateral wellbore **1670** without the need for a deflector, as discussed above.

Turning to FIG. **16**C, the bendable deflection tip **1340** of the lateral locating assembly **1600** moves back to the straight position, and continues downhole.

Turning to FIG. **16**D, the lateral locating assembly **1600** begins to engage with the lateral liner **1620**. Again, the shroud **1380** is too large to pass through the lateral liner **1620**.

Turning to FIG. **16**E, the lateral locating assembly **1600** continues to move downhole, thereby shifting the sliding sleeve **1360** from the first position sealing the one or more production ports **1350** to the second position exposing the one or more production ports **1350**.

Turning to FIG. **16**F, the lateral locating assembly **1600** continues downhole. As the lateral locating assembly **1600** is coupled to a downhole end of a lateral bore leg **1645** of a multilateral junction **1630**, the mainbore leg **1640** of the multilateral junction **1630** engages with a mainbore completion **1642**, while the lateral bore leg **1645** of the multilateral junction **1630** engages with a lateral bore completion **1647**. At this stage, hydrocarbons may be produced through the exposed one or more production ports **1350** when the lateral locating assembly **1600** is properly placed within the lateral bore completion **1647**.

Turning to FIGS. **17**A through **17**D, illustrated are different operational views of a multilateral junction **1700** designed, manufactured and/or operated according to one or more embodiments of the disclosure. The multilateral junction **1700**, in the illustrated embodiment, includes a y-block **1710**. The y-block, in one or more embodiments, includes a housing **1715** having a first end and a second opposing end, a single first bore extending into the housing **1715** from the first end, the single first bore defining a first centerline, and second and third separate bores extending into the housing **1715** and branching off from the single first bore, the second bore defining a second centerline and the third bore defining a third centerline. In the illustrated embodiment, a mainbore leg **1720** has a first mainbore leg end and a second opposing mainbore leg end, wherein the first mainbore leg end is coupled to the second bore. In the illustrated embodiment, a lateral bore leg **1730** has a first lateral bore leg end and a second opposing lateral bore leg end, wherein the first lateral bore leg end is coupled to the third bore.

As shown in the embodiment of FIGS. **17**A through **17**D, a lateral locating assembly **1740** is coupled to the second opposing lateral bore leg end. The lateral locating assembly **1740** is similar in many respects to the lateral locating assembly **1300** discussed above. Accordingly, like reference numbers may be used to indicate similar, if not identical, features. In the illustrated embodiment, the lateral locating assembly **1740** includes: 1) a tubular; and 2) a bendable deflection tip coupled to the tubular, the bendable deflection tip configured to move between a straight position and a bent position upon the application of fluid pressure thereto.

FIG. **17**A illustrates the lateral locating assembly **1740** in the run-in-hole position. FIG. **17**B illustrates the lateral locating assembly **1740** with its bendable deflection tip in the bent position. FIG. **17**C illustrates the lateral locating assembly **1740** with its bendable deflection tip back in the straight position, but as it might look when the lateral bore leg **1730** has entered the lateral wellbore. FIG. **17**D illustrates the lateral locating assembly **1740** with its sliding sleeve in the second position, thereby exposing the one or more production ports.

Turning now to FIGS. **18** through **33**, illustrated is a method for forming, accessing, and completing a well system **1800** in accordance with one or more embodiments of the disclosure. FIG. **18** is a schematic of the well system **1800** at the initial stages of formation. A main wellbore **1810** may be drilled, for example by a rotary steerable system at the end of a drill string and may extend from a well origin (not shown), such as the earth's surface or a sea bottom. The main wellbore **1810** may be lined by one or more casings **1815**, **1820**, each of which may be terminated by a shoe **1825**, **1830**.

The well system **1800** of FIG. **18** may additionally include a main wellbore completion **1840** positioned in the main wellbore **1810**. The main wellbore completion **1840** may, in certain embodiments, include a main wellbore liner **1845** (e.g., with frac sleeves in one embodiment), as well as one or more packers (e.g., swell packers in one embodiment).

Turning to FIG. **19**, illustrated is the well system **1800** of FIG. **18** after installing a multilateral anchor **1910** in the main wellbore **1810** using a running tool **1905**. The multilateral anchor **1910** may include a stinger with seals **1920**, a perf joint **1930**, a seal bore **1940**, a collet profile **1950** and a slotted alignment muleshoe **1960**, among other features.

Turning to FIG. **20**, illustrated is the well system **1800** of FIG. **19** after removing the running tool **1905**.

Turning to FIG. **21**, illustrated is the well system **1800** of FIG. **20** after positioning a whipstock **2110** downhole at a location where a lateral wellbore is to be formed. The whipstock **2110**, in at least one embodiment, is similar to the whipstock **900** discussed above, and thus may include: 1) a whipface having an angled casing string exit surface; 2) a sub detachably coupled to the whipface; and 3) a bottom hole assembly fixedly coupled to the sub, the bottom hole assembly having one or more seals along an inner surface thereof.

In certain embodiments, such as that shown in FIG. **21**, the whipstock **2110** is made up with a lead mill bit **2140**, for example using a shear bolt, and then run in hole on a drill string **2150**. The lead mill bit **2140** and the whipstock **2110** may comprise one or more of the mill bits and/or whipstocks discussed in the paragraphs above. The WOT/MWD tool may be employed to orient the whipstock **2110**.

Turning to FIG. **22**, illustrated is the well system **1800** of FIG. **21** after setting down weight to shear the shear bolt between the lead mill bit **2140** and the whipstock **2110**, and then milling an initial window pocket **2210**. In certain embodiments, the initial window pocket **2210** is between 1.5 m and 7.0 m long, and in certain other embodiments about 2.5 m long, and extends through the casing **1820**. Thereafter, a circulate and clean process could occur, and then the drill string **2150** and lead mill **2140** may be pulled out of hole.

Turning to FIG. **23**, illustrated is the well system **1800** of FIG. **22** after running a lead mill bit **2320** and watermelon mill bit **2330** downhole on a drill string **2310**. In the embodiments shown in FIG. **23**, the drill string **2310**, lead mill bit **2320** and watermelon mill bit **2330** drill a full window pocket **2340** in the formation. In certain embodiments, the full window pocket **2340** is between 5 m and 10 m long, and in certain other embodiments about 8.5 m long. Thereafter, a circulate and clean process could occur, and then the drill string **2310**, lead mill bit **2320** and watermelon mill bit **2330** may be pulled out of hole.

Turning to FIG. **24**, illustrated is the well system **1800** of FIG. **23** after running in hole a drill string **2410** with a rotary steerable assembly **2420**, drilling a tangent **2430** following an inclination of the whipstock **2110**, and then continuing to drill the lateral wellbore **2440** to depth. Thereafter, the drill string **2410** and rotary steerable assembly **2420** may be pulled out of hole.

Turning to FIG. **25**, illustrated is the well system **1800** of FIG. **24** after employing an inner string **2510** to position a lateral wellbore completion **2520** in the lateral wellbore **2440**. The lateral wellbore completion **2520** may, in certain embodiments, include a lateral wellbore liner **2530** (e.g., with frac sleeves in one embodiment), as well as one or more packers.

Turning to FIG. **26**, illustrated is the well system **1800** of FIG. **25** after pulling the inner string **2510** back into the main wellbore **1810**, and engaging with the whipstock **2110**. While this is shown as a single trip, other embodiments may exist wherein two or more separate trips are desired.

Turning to FIG. **27**, illustrated is the well system **1800** of FIG. **26** after detaching the whipface **2710** of the whipstock **2110** from the sub **2720** and bottom hole assembly **2730**. This process may be similar to that disclosed above with regard to FIGS. **11**A through **11**E.

Turning to FIG. **28**, illustrated is the well system **1800** of FIG. **27** after further drawing the whipface **2710** uphole, again similar to that disclosed above with regard to FIGS. **11**A through **11**E.

Turning to FIG. **29**, illustrated is the well system **1800** of FIG. **28** after fully drawing the whipface **2710** uphole, again similar to that disclosed above with regard to FIGS. **11**A through **11**E.

Turning to FIG. **30**, illustrated is the well system **1800** of FIG. **29** after positioning a multilateral junction **3010** designed, manufactured and/or operated according to the disclosure within the main wellbore **1810** using a running tool **3005**. The multilateral junction **3010** may be similar to one or more of the embodiments disclosed above, and thus may include a lateral locating assembly **3020**. In the given embodiment, a sliding sleeve of the lateral locating assembly **3020** is in a first position (e.g., closed position), and thus is sealing the one or more production ports thereof.

Turning to FIG. **31**, illustrated is the well system **1800** of FIG. **30** after causing the bendable deflection tip of the lateral locating assembly **3020** to move from the straight position to the bent position, such that it can enter the lateral wellbore **2440**. Again, the sliding sleeve remains in the first position (e.g., closed position) at this moment.

Turning to FIG. **32**, illustrated is the well system **1800** of FIG. **31** after continuing to push the multilateral junction **3010** downhole until the shroud of the lateral locating assembly **3020** engages with a lateral liner of the lateral bore completion, and thus slides the sliding sleeve from the first position to a second position exposing the one or more production ports.

Turning to FIG. **33**, illustrated is the well system **1800** of FIG. **32** after removing the running tool **3005**, thereby leaving the lateral locating assembly **3020** with its sliding sleeve in the second position (e.g., open position).

Aspects disclosed herein include:

A. A whipstock, the whipstock including: 1) a whipface having an angled casing string exit surface; 2) a sub detachably coupled to the whipface; and 3) a bottom hole assembly fixedly coupled to the sub, the bottom hole assembly having one or more seals along an inner surface thereof.

B. A well system, the well system including: 1) a main wellbore extending through one or more subterranean formations; 2) a casing string located within the main wellbore; and 3) a whipstock located in the casing string proximate a junction where a lateral wellbore is to exit the main wellbore, the whipstock including: a) a whipface having an angled casing string exit surface; b) a sub detachably coupled to the whipface; and c) a bottom hole assembly fixedly coupled to the sub, the bottom hole assembly having one or more seals along an inner surface thereof.

C. A method, the method including: 1) forming a main wellbore through one or more subterranean formations; 2) positioning a casing string within the main wellbore; and 3) locating a whipstock in the casing string proximate a junction where a lateral wellbore is to exit the main wellbore, the whipstock including: a) a whipface having an angled casing string exit surface; b) a sub detachably coupled to the whipface; and c) a bottom hole assembly fixedly coupled to the sub, the bottom hole assembly having one or more seals along an inner surface thereof.

D. A lateral locating assembly, the lateral locating assembly including: 1) a tubular; 2) a bendable deflection tip coupled to the tubular, the bendable deflection tip configured to move between a straight position and a bent position upon the application of fluid pressure thereto; 3) one or more production ports coupling an interior of the tubular and an exterior of the tubular; and 4) a sliding sleeve positioned about the one or more production ports, the sliding sleeve configured to seal the one or more production ports when in a first position and expose the one or more production ports when in a second position.

E. A well system, the well system including: 1) a main wellbore extending through one or more subterranean formations; 2) a lateral wellbore extending from the main wellbore; and 3) a lateral locating assembly located in the main wellbore proximate an intersection between the main wellbore and the lateral wellbore, the lateral locating assembly including: a) a tubular; b) a bendable deflection tip coupled to the tubular, the bendable deflection tip configured to move between a straight position and a bent position upon the application of fluid pressure thereto; c) one or more production ports coupling an interior of the tubular and an exterior of the tubular; and d) a sliding sleeve positioned about the one or more production ports, the sliding sleeve configured to seal the one or more production ports when in a first position and expose the one or more production ports when in a second position.

F. A method, the method including: 1) forming a main wellbore through one or more subterranean formations; 2) forming a lateral wellbore from the main wellbore; and 3) positioning a lateral locating assembly proximate an intersection between the main wellbore and the lateral wellbore, the lateral locating assembly including: a) a tubular; b) a bendable deflection tip coupled to the tubular, the bendable deflection tip configured to move between a straight position and a bent position upon the application of fluid pressure thereto; c) one or more production ports coupling an interior of the tubular and an exterior of the tubular; and d) a sliding sleeve positioned about the one or more production ports, the sliding sleeve configured to seal the one or more production ports when in a first position and expose the one or more production ports when in a second position.

G. A multilateral junction, the multilateral junction including: 1) a y-block, the y-block including: a) a housing having a first end and a second opposing end; b) a single first bore extending into the housing from the first end; and c) second and third separate bores extending into the housing and branching off from the single first bore; 2) a mainbore leg having a first mainbore leg end coupled to the second bore and a second opposing mainbore leg end; 3) a lateral bore leg having a first lateral bore leg end coupled to the third bore and a second opposing lateral bore leg end; and 4) a lateral locating assembly coupled to the second opposing lateral bore leg end, the lateral locating assembly including: a) a tubular; and b) a bendable deflection tip coupled to the tubular, the bendable deflection tip configured to move between a straight position and a bent position upon the application of fluid pressure thereto.

H. A well system, the well system including: 1) a main wellbore extending through one or more subterranean formations; 2) a lateral wellbore extending from the main wellbore; and 3) a multilateral junction located in the main wellbore, the multilateral junction including: a) a y-block, the y-block including: i) a housing having a first end and a second opposing end; ii) a single first bore extending into the housing from the first end; and iii) second and third separate bores extending into the housing and branching off from the single first bore; b) a mainbore leg having a first mainbore leg end coupled to the second bore and a second opposing mainbore leg end; c) a lateral bore leg having a first lateral bore leg end coupled to the third bore and a second opposing lateral bore leg end; and d) a lateral locating assembly coupled to the second opposing lateral bore leg end, the lateral locating assembly including: i) a tubular; and ii) a bendable deflection tip coupled to the tubular, the bendable deflection tip configured to move between a straight position and a bent position upon the application of fluid pressure thereto.

I. A method, the method including: 1) forming a main wellbore through one or more subterranean formations; 2) forming a lateral wellbore from the main wellbore; and 3) positioning a multilateral junction proximate an intersection between the main wellbore and the lateral wellbore, the multilateral junction including: a) a y-block, the y-block including: i) a housing having a first end and a second opposing end; ii) a single first bore extending into the housing from the first end; and iii) second and third separate bores extending into the housing and branching off from the single first bore; b) a mainbore leg having a first mainbore leg end coupled to the second bore and a second opposing mainbore leg end; c) a lateral bore leg having a first lateral bore leg end coupled to the third bore and a second opposing lateral bore leg end; and d) a lateral locating assembly coupled to the second opposing lateral bore leg end, the lateral locating assembly including: i) a tubular; and ii) a bendable deflection tip coupled to the tubular, the bendable deflection tip configured to move between a straight position and a bent position upon the application of fluid pressure thereto.

Aspects A, B, C, D, E, F, G, H and I may have one or more of the following additional elements in combination: Element 1: wherein the sub is a lower sub, and further including an upper sub fixedly coupled to the whipface between the whipface and the lower sub. Element 2: wherein the upper sub includes a tubular that extends within the lower sub and at least a portion of the bottom hole assembly. Element 3: further including one or more debris collection devices located within the tubular. Element 4: further including a first course debris filter located within the tubular and a second fine debris filter located within the tubular downhole of the first course debris filter. Element 5: further including one or more shear features detachably coupling the whipface and upper sub to the lower sub. Element 6: further including a plurality of members and member profiles in the lower sub and upper sub, the members and member profiles configured to cooperate to rotationally fix the lower sub and the upper sub. Element 7: wherein the bottom hole assembly includes an alignment key located along an outer surface thereof. Element 8: wherein the bottom hole assembly includes one or more second seals located along the outer surface thereof proximate a downhole end thereof, the one or more second seals configured to engage and seal with a mainbore completion. Element 9: wherein the bottom hole assembly further includes an anchor positioned between the alignment key and the one or more second seals, the anchor configured to laterally fix the bottom hole assembly relative to the mainbore completion. Element 10: further including positioning a mainbore completion within the main wellbore prior to locating the whipstock in the casing string. Element 11: further including milling a pocket in the casing string at the junction using a milling tool and the whipface. Element 12: further including drilling the lateral wellbore from the main wellbore after milling the pocket. Element 13: further including positioning a lateral bore completion within the lateral wellbore after drilling. Element 14: further including detaching the whipface from the sub after positioning the lateral bore completion within the lateral wellbore, the detaching exposing the more or more seals. Element 15: further including placing a multilateral junction including a mainbore leg and a lateral bore leg within the main wellbore. Element 16: wherein placing the multilateral junction includes stabbing the mainbore leg into the one or more seals of the bottom hole assembly and stabbing the lateral bore leg into additional seals of the lateral bore completion. Element 17: further including a shroud positioned about the tubular and removably coupled to the sliding sleeve. Element 18: wherein the sliding sleeve includes a collet, the collet fixing the sliding sleeve to the shroud when the sliding sleeve is in the first position and releasing the sliding sleeve from the shroud when the sliding sleeve is in the second position. Element 19: wherein the shroud includes a first collet groove configured to engage the collet in an expanded state to fix the sliding sleeve to the shroud when the sliding sleeve is in the first position and the tubular includes a second collet groove configured to accept the collet in a collapsed state to release the sliding sleeve from the shroud when the sliding sleeve is in the second position. Element 20: further including a snap ring and snap ring groove located in ones of the tubular and the sliding sleeve, the snap ring configured to engage with the snap ring groove when the sliding sleeve is in the second position to fix the sliding sleeve in the second position.

Element 21: further including a packer coupled to the tubular uphole of the bendable deflection tip. Element 22: wherein the packer is a swell packer protected by the shroud when the sliding sleeve is in the first position. Element 23: further including one or more swab cups protected by the shroud when the sliding sleeve is in the first position, the one or more swab cups configured to provide a seal until the swell packer fully sets. Element 24: further including one or more shear features releasably coupled to the shroud to hold the sliding sleeve in the first position. Element 25: further including one or more no go blades coupled to a tip of the bendable deflection tip, the one or more no go blades configured to prevent the bendable deflection tip from accessing a main wellbore completion. Element 26: further including a shroud positioned about the tubular and removably coupled to the sliding sleeve. Element 27: further including applying fluid pressure to the bendable deflection tip to move the bendable deflection tip to the bent position. Element 28: further including entering the lateral wellbore with the bendable deflection tip in the bent position. Element 29: further including returning the bendable deflection tip back to the straight position from the bent position after entering the lateral wellbore. Element 30: further including pushing the lateral locating assembly downhole until the shroud engages with a tubular, the pushing moving the sliding sleeve from the first position to the second position and releasing the sliding sleeve from the shroud. Element 31: further including continuing to push the lateral locating assembly with the sliding sleeve in the second position downhole until properly placed within a lateral bore completion. Element 32: further including producing hydrocarbons through the exposed one or more production ports when the lateral locating assembly is properly placed within the lateral completion. Element 33: further including: 1) one or more production ports coupling an interior of the tubular and an exterior of the tubular; 2) a sliding sleeve positioned about the one or more production ports, the sliding sleeve configured to seal the one or more production ports when in a first position and expose the one or more production ports when in a second position; and 3) a shroud positioned about the tubular and removably coupled to the sliding. Element 34: wherein the mainbore leg is sealingly coupled with a mainbore completion in the main wellbore and the lateral bore leg is sealingly coupled with a lateral bore completion in the lateral bore. Element 35: further including applying fluid pressure to the bendable deflection tip to move the bendable deflection tip to the bent position. Element 36: further including pushing the multilateral junction downhole until the lateral bore leg having the bendable deflection tip in the bent position enters the lateral wellbore. Element 37: wherein pushing the multilateral junction downhole until the lateral bore leg having the bendable deflection tip in the bent position enters the lateral wellbore occurs without the use of a deflector assembly in the main wellbore. Element 38: further including returning the bendable deflection tip back to the straight position from the bent position after the lateral bore leg having the bendable deflection tip in the bent position enters the lateral wellbore. Element 39: further including continuing to push the multilateral junction downhole until the mainbore leg sealingly engages with a mainbore completion in the main wellbore and the lateral bore leg sealingly engages with a lateral bore completion in the lateral wellbore. Element 40: further including producing hydrocarbons through the multilateral junction having the deflection tip in the straight position. Element 41: further including: 1) one or more production ports coupling an interior of the tubular and an exterior of the tubular; and 2) a sliding sleeve positioned about the one or more production ports, the sliding sleeve configured to seal the one or more production ports when in a first position and expose the one or more production ports when in a second position; and 3) a shroud positioned about the tubular and removably coupled to the sliding sleeve.

Those skilled in the art to which this application relates will appreciate that other and further additions, deletions, substitutions and modifications may be made to the described embodiments.

What is claimed is:

1. A whipstock, comprising:

a whipface having an angled casing string exit surface;

an upper sub fixedly coupled to the whipface;

a lower sub detachably coupled to the whipface and upper sub via one or more shear features; and

a bottom hole assembly fixedly coupled to the lower sub, the bottom hole assembly having one or more seals along an inner surface thereof, wherein the bottom hole assembly includes an alignment key located along an outer surface thereof.

2. The whipstock as recited in claim **1**, wherein the upper sub includes a tubular that extends within the lower sub and at least a portion of the bottom hole assembly.

3. The whipstock as recited in claim **2**, further including one or more debris collection devices located within the tubular.

4. The whipstock as recited in claim **2**, further including a first course debris filter located within the tubular and a second fine debris filter located within the tubular downhole of the first course debris filter.

5. The whipstock as recited in claim **1**, further including a plurality of members and member profiles in the lower sub and upper sub, the members and member profiles configured to cooperate to rotationally fix the lower sub and the upper sub.

6. The whipstock as recited in claim **1**, wherein the bottom hole assembly includes one or more second seals located along the outer surface thereof proximate a downhole end thereof, the one or more second seals configured to engage and seal with a mainbore completion.

7. The whipstock as recited in claim **6**, wherein the bottom hole assembly further includes an anchor positioned between the alignment key and the one or more second seals, the anchor configured to laterally fix the bottom hole assembly relative to the mainbore completion.

8. A well system, comprising:

a main wellbore extending through one or more subterranean formations;

a casing string located within the main wellbore; and

a whipstock located in the casing string proximate a junction where a lateral wellbore is to exit the main wellbore, the whipstock including:

a whipface having an angled casing string exit surface;

an upper sub fixedly coupled to the whipface;

a lower sub detachably coupled to the whipface and upper sub via one or more shear features; and

a bottom hole assembly fixedly coupled to the lower sub, the bottom hole assembly having one or more seals along an inner surface thereof, wherein the bottom hole assembly includes an alignment key located along an outer surface thereof.

9. The well system as recited in claim **8**, wherein the upper sub includes a tubular that extends within the lower sub and at least a portion of the bottom hole assembly.

10. The well system as recited in claim **9**, further including one or more debris collection devices located within the tubular.

11. The well system as recited in claim **9**, further including a first course debris filter located within the tubular and a second fine debris filter located within the tubular downhole of the first course debris filter.

12. The well system as recited in claim **8**, further including a plurality of members and member profiles in the lower sub and upper sub, the members and member profiles configured to cooperate to rotationally fix the lower sub and the upper sub.

13. The well system as recited in claim **8**, wherein the alignment key is engaged with a muleshoe within the casing string.

14. The well system as recited in claim **13**, wherein the bottom hole assembly includes one or more second seals located along the outer surface thereof proximate a downhole end thereof, the one or more second seals engaged and sealing with a mainbore completion located in the main wellbore downhole of the whipstock.

15. The well system as recited in claim **14**, wherein the bottom hole assembly further includes an anchor positioned between the alignment key and the one or more second seals, the anchor configured to laterally fix the bottom hole assembly relative to the mainbore completion.

16. A method, comprising:

forming a main wellbore through one or more subterranean formations;

positioning a casing string within the main wellbore; and

locating a whipstock in the casing string proximate a junction where a lateral wellbore is to exit the main wellbore, the whipstock including:

a whipface having an angled casing string exit surface;

an upper sub fixedly coupled to the whipface;

a lower sub detachably coupled to the whipface and upper sub via one or more shear features; and

a bottom hole assembly fixedly coupled to the lower sub, the bottom hole assembly having one or more seals along an inner surface thereof, wherein the bottom hole assembly includes an alignment key located along an outer surface thereof.

17. The method as recited in claim **16**, further including positioning a mainbore completion within the main wellbore prior to locating the whipstock in the casing string.

18. The method as recited in claim **17**, further including milling a pocket in the casing string at the junction using a milling tool and the whipface.

19. The method as recited in claim **18**, further including drilling the lateral wellbore from the main wellbore after milling the pocket.

20. The method as recited in claim **19**, further including positioning a lateral bore completion within the lateral wellbore after drilling.

21. The method as recited in claim **20**, further including detaching the whipface from the lower sub after positioning the lateral bore completion within the lateral wellbore, the detaching exposing the more or more seals.

22. The method as recited in claim **21**, further including placing a multilateral junction including a mainbore leg and a lateral bore leg within the main wellbore.

23. The method as recited in claim **22**, wherein placing the multilateral junction includes stabbing the mainbore leg into the one or more seals of the bottom hole assembly and stabbing the lateral bore leg into additional seals of the lateral bore completion.

24. The method as recited in claim **16**, wherein the upper sub includes a tubular that extends within the lower sub and at least a portion of the bottom hole assembly.

25. The method as recited in claim **24**, further including one or more debris collection devices located within the tubular.

26. The method as recited in claim **24**, further including a first course debris filter located within the tubular and a second fine debris filter located within the tubular downhole of the first course debris filter.

27. The method as recited in claim **16**, further including a plurality of members and member profiles in the lower sub and upper sub, the members and member profiles configured to cooperate to rotationally fix the lower sub and the upper sub.

28. The method as recited in claim **16**, wherein the alignment key is engaged with a muleshoe within the casing string.

29. The method as recited in claim **28**, wherein the bottom hole assembly includes one or more second seals located along the outer surface thereof proximate a downhole end thereof, the one or more second seals engaged and sealing with a mainbore completion located in the main wellbore downhole of the whipstock.

30. The method as recited in claim **29**, wherein the bottom hole assembly further includes an anchor positioned between the alignment key and the one or more second seals, the anchor configured to laterally fix the bottom hole assembly relative to the mainbore completion.

31. A whipstock, comprising:

a whipface having an angled casing string exit surface;

an upper sub fixedly coupled to the whipface;

a lower sub detachably coupled to the whipface and upper sub via one or more shear features, wherein the upper sub includes a tubular that extends within the lower sub and at least a portion of the bottom hole assembly, and further including one or more debris collection devices located within the tubular; and

a bottom hole assembly fixedly coupled to the lower sub, the bottom hole assembly having one or more seals along an inner surface thereof.

32. A whipstock, comprising:

a whipface having an angled casing string exit surface;

an upper sub fixedly coupled to the whipface;

a lower sub detachably coupled to the whipface and upper sub via one or more shear features;

a plurality of members and member profiles in the lower sub and upper sub, the members and member profiles configured to cooperate to rotationally fix the lower sub and the upper sub; and

a bottom hole assembly fixedly coupled to the lower sub, the bottom hole assembly having one or more seals along an inner surface thereof.

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