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(54) **Multidirectional wellbore penetration system and methods of use**

(57) A drilling assembly (100) includes a hydraulic jet (102) disposed on a downhole end of a fluid line (108), and one or more adjustable jet nozzles (104, 106) on the hydraulic jet (102) in multiple angular orientations relative to a central axis of the hydraulic jet (102). The one or more adjustable jet nozzles (104, 106) provide fluid pressure to penetrate a formation (5) and cut one or more angular channels (12).

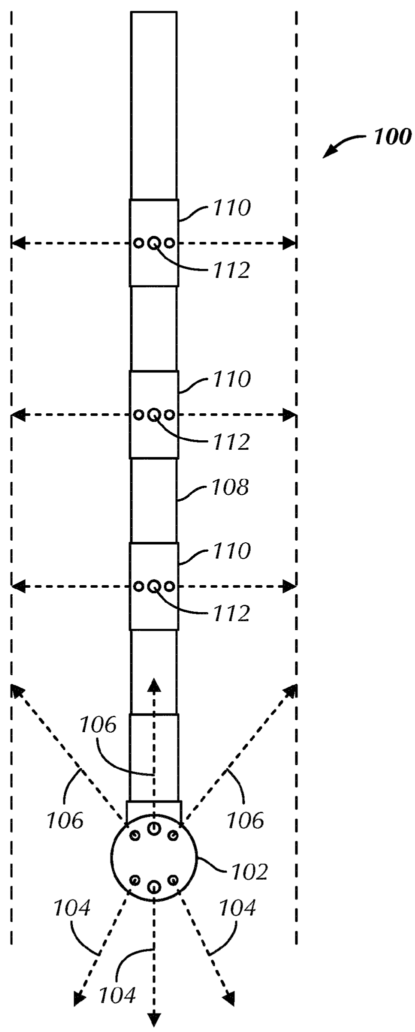

FIG. 2

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Description

FIELD OF THE DISCLOSURE

[0001] Embodiments disclosed herein relate generally to drilling wellbores. More particularly, embodiments disclosed herein relate to apparatus and methods for multi-directional and multi-angle penetrations through a formation from any initial wellbore.

BACKGROUND

[0002] In drilling a borehole in the earth, such as for the recovery of hydrocarbons or for other applications, it is conventional practice to connect a drill bit on the lower end of an assembly of drill pipe sections that are connected end-to-end so as to form a drillstring. The drill bit is rotated by rotating the drill string at the surface or by actuation of downhole motors or turbines, or by both methods. With weight applied to the drill string, the rotating bit engages the earthen formation causing the bit to cut through the formation material by either abrasion, fracturing, or shearing action, or through a combination of all cutting methods, thereby forming a borehole along a predetermined path toward a taret zone.

[0003] Traditionally, drilled oil and gas wells penetrate the formation with a single wellbore, thereby catching the oil and gas from the connected and drainable radius only. Horizontal wells may be single or multiple in direction, but in most cases are limited in multitude and high in cost. Likewise, radial drilling may also be single directed and is limited by penetration and area coverage.

[0004] Accordingly, there exists a need for improved well productivity.

SUMMARY OF THE DISCLOSURE

[0005] In one aspect, embodiments disclosed herein relate to a drilling assembly including a hydraulic jet disposed on a downhole end of a fluid line and one or more adjustable jet nozzles on the hydraulic jet in multiple angular orientations relative to a central axis of the hydraulic jet, wherein the one or more adjustable jet nozzles provide fluid pressure to penetrate a formation and cut one or more angular channels.

[0006] In other aspects, embodiments disclosed herein relate to a cutting device including a cutter disposed on an end thereof; a spacer section proximate to the cutter; and a guide channel having a radius of curvature, wherein a length of the spacer section corresponds with the guide channel radius of curvature to create a particular cutter path angle through a casing wall.

[0007] In other aspects, embodiments disclosed herein relate to a bottomhole assembly comprising the abovementioned drilling assembly and cutting device.

[0008] In other aspects, embodiments disclosed herein relate to a method of drilling a formation including inserting, into a formation channel, a hydraulic jet comprising one or more multi-directional jet nozzles, providing high pressure fluid through the multi-directional jet nozzles; and cutting one or more angular channels through the formation.

[0009] Other aspects and advantages of the invention will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0010] Figure 1 shows a cross-section view of field drainage laterals crossing various producing and non-producing reservoir layers.

[0011] Figure 2 shows a side view of a drilling assembly in accordance with one or more embodiments of the present disclosure.

[0012] Figure 3 shows a cross-section view of a guide channel of a cutting device in accordance with one or more embodiments of the present disclosure.

[0013] Figure 4 shows a side view of a cutting device in accordance with one or more embodiments of the present disclosure.

[0014] Figure 5 shows a side view of a cutting device for calculating an optimized cutter length in accordance with one or more embodiments of the present disclosure.

DETAILED DESCRIPTION

[0015] The following is directed to various exemplary embodiments of the disclosure. The embodiments disclosed should not be interpreted, or otherwise used, as limiting the scope of the disclosure, including the claims. In addition, those having ordinary skill in the art will appreciate that the following description has broad application, and the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to suggest that the scope of the disclosure, including the claims, is limited to that embodiment.

[0016] In one aspect, embodiments disclosed herein relate to a bottomhole assembly and methods of drilling a formation which may result in production maximization of hydrocarbons, water, or gas-bearing formations.

[0017] As shown in Figure 1, a formation 5 is penetrated by high pressure fluid such that a multitude of channels 12 are formed from an original wellbore 10. Original wellbore 10 may be a vertical, inclined, or horizontal wellbore. Channels 12 may extend from wellbore 10 in any direction and at any angle. This network of channels 12 allows for maximum drainage of any interconnected fluid or gas bearing zones of the formation 5. The channels 12 may traverse multiple producing and non-producing zones of the formation at an angle into the reservoir and may connect all present fractures, layers, and cavities that are outside the reach of traditionally drilled vertical or angled wellbores. Additionally, the channels 12 may also be used as conduits for injected chemicals, proppants, steam, pressure, and/or fluids, which may add to the productivity of the reservoir.

[0018] The bottomhole assembly may be hydraulically stabilized and may comprise a drilling assembly 100, which is shown in Figure 2. The drilling assembly 100 may have hydraulic jet nozzles. The bottomhole assembly may include a hydraulic jet and a cutting device, for example a casing cutter as described below, where the hydraulic jet may be a static or dynamic hydraulic jet. Referring to Figure 2, a side view of a drilling assembly 100 comprising hydraulic jet 102 in accordance with one or more embodiments of the present disclosure is shown. The hydraulic jet 102 includes a plurality of multi-directional jet nozzles 104 and 106, which may be angled and sized jet nozzles, including, for example, forward-facing jet nozzles 104 and rearward-facing jet nozzles 106. As used herein, "forward-facing" means providing fluid coverage of a forward facing 180 degree hemisphere. Likewise, as used herein, "rearward-facing" means providing fluid coverage of a rearward facing 180 degree hemisphere (opposite that of the forward facing 180 degree hemisphere). The forward and rearward jet nozzles 104 and 106 are arranged at specific angles, depending upon formation characteristics generally. The forward and rearward jet nozzles 104 and 106 may be arranged in any direction to cover and provide fluid pressure over an entire 360 degree circumference around the hydraulic jet 102.

[0019] The multi-directional jet nozzles 104 and 106 may include adjustable jet nozzles which are manual or automated, and the jet nozzles may be adjusted at the surface (prior to inserting the jet into the wellbore), may be remotely adjusted downhole, or both. Remote adjustment of the nozzle may be performed, for example, by circulation of selected chemicals through the jet nozzles, where the selected chemicals dissolve, remove or otherwise eliminate minute sections or portions of the inner diameter of the jet nozzle, such as a ring of dissolvable material proximate the jet opening.

[0020] Jet nozzles disclosed herein may be static or dynamic, as noted above. As used herein, "dynamic" may refer to jet nozzles that move, skip from a fractional rotation to a full single rotation, vibrate, or rotate during use. For example, "dynamic jet nozzles" may refer to jet nozzles that are vibrating, flip-flopping ½ or ¾ rotations, or rotating jets. Furthermore, as used herein, "static" may refer to jet nozzles that are fixed at a particular angle. Those skilled in the art will appreciate that any combination of only dynamic jet nozzles, only static jet nozzles, and both dynamic and static jet nozzles may be used in accordance with one or more embodiments of the present disclosure.

[0021] Jet sizing (*i.e.,* diameter or taper) of the jet nozzles may be determined by the hydraulic fluid pressure desired for penetration into a particular formation. The forward and rearward-facing jet nozzles 104 and 106 may be similarly sized in certain embodiments, while in other embodiments, the jet nozzles may vary in size. For example, sizing of the jet nozzles may take into account jetting pressure, which is a direct function of formation variables such as compressive strength, porosity, and consolidation. Such formation variables may increase or decrease with formation depth and reservoir age. Formation penetration is achieved by nozzle design that provides sufficient erosional forces (*i.e.,* sufficient fluid volume rate) and sufficient impact forces (*i.e.,* sufficient fluid pressure) to create a lateral channel through the reservoir. Thus, for instance, jet nozzles in accordance with one or more embodiments of the present disclosure may provide a fluid volume rate of between about 11.4 and about 94.6 1 (about 3 and about 25 gallons) per minute and a fluid pressure of between about 20.7 MPa and about 137.9 MPa (about 3,000 and 20,000 psi).

[0022] Still further, sizes of jet nozzles 104 and 106 may vary between about 0.035 cm and about 0.254 cm (about 0.014 inches and about 0.1 inches) or greater in certain embodiments. Additionally, the jet nozzles 104 and 106 may be positioned at angles from less than about 5 degrees to about 45 degrees relative to a central axis of the hydraulic jet 102 to provide full hole penetration. In harder formations, such jet angles may be closer to about 45 degrees with smaller jet nozzle sizes, whereas in softer and unconsolidated formations such parameters may have smaller angles and larger jet nozzle sizes. Further still, the jets may be either static or dynamic during use. For example, penetration may be enhanced by a static jet. However, dynamic jets, static, pulsing, or rotating, may be used for more dense and harder rock penetration, in addition to varying the jet nozzle angles and sizes.

[0023] The hydraulic jet 102 may be connected by a fluid line 108, for example a high pressure flexible fluid line, to one or more hydraulic centralizers 110 disposed along a length of the fluid line 108. The hydraulic centralizers 110 include various sizes of jet nozzles 112 that form circumferential fluid streams of limited length and impact radially outwards. The circumferential fluid streams may be arranged such that a few centimeters (inches) of solid fluid stream is directed radially outward before the solid fluid stream diffuses in a spray-like pattern to reduce the erosional effect of the centralizer. For example, in certain embodiments, the solid fluid stream may be between about 2.54 cm and about 12,70 cm (about 1 inch and about 5 inches). In other embodiments, the solid fluid stream may be between about 2.54 cm and about 7.62 cm (about 1 inch and about 3 inches). Furthermore, the jet nozzles 112 may be evenly spaced about a circumference of the hydraulic centralizers 110 in certain embodiments. In other embodiments, the jet nozzles 112 may be unequally spaced about the circumference of the hydraulic centralizers 110, depending on such characteristics, as formation hardness and erodability, fluid pressure, and other parameters.

[0024] The circumferential jet stream from the hydraulic centralizers 110 centers the one or more circumferential jet arrangements such that an inherent stiffness of the fluid line 108 between the hydraulic centralizers 110 is maintained. For example, a centralization effect may be achieved by having a multitude of circumferential jet streams centralizing the system. Rigidity may be obtained by placing the one or more hydraulic centralizers 110 at locations along a length of the fluid line 108 in direct correlation with a stiffness coefficient of the fluid line 108 (which may be steel reinforced hose in certain instances). The force that emits from the hydraulic centralizers 110 may be a function of the jet nozzles 112 in the centralizer and hardness of the formation. Thus, the one or more hydraulic centralizers 110 act as a centralizing and stabilizing contact point against the wellbore wall.

[0025] The drilling assembly 100 may allow for the use of and/or mixing of various types of jetting fluids, including, but not limited to, water, chemical combinations to stabilize a formation from hydration or assist the penetration by chemical leaching or to clean out the formation of corrosion, asphalts, paraffins, and other clogging or production inhibiting compounds that may be present in the formation or are induced by exploration and production of the reservoir.

[0026] The bottomhole assembly may further include a cutting tool, for example a cutting device 120. The cutting device 120 may cut through a casing wall. The cutting device 120 may exit laterally from the main vertical wellbore casing ahead of the hydraulic jet 102 of the drilling assembly 100. As shown in Figure 3, the cutting device 120 may include a guide body 140 that has a guide channel 142 through its center, which may be angled to at any desired inclination to deflect the cutting device 120 at a particular angle into contact with the casing. The guide body 140 fits within a wellbore casing to be cut and is decentered within the wellbore casing by one or more spring-loaded pads and/or expanding locking dogs 144 to obtain flush wall contact at the exit point of guide channel 142. As used herein, "de-centered" refers to using, for example, the one or more spring-loaded pads 144 urge the outer surface of the guide body 140 into flush contact with an inner surface of the wellbore casing (not shown), such that the outer surface of the guide body 140 and the inner surface of the wellbore casing are substantially parallel and in flush contact. The guide channel 142 dictates the angle at which the cutting device120 drills into the formation, and in effect, the angle at which the hydraulic jet 102 of the drilling assembly 100 is ultimately inserted into the formation. As such, the guide channel 142 may be angled and configured having a radius of curvature 143, which cutter having an optimized cutter length (as described in more detail below), provides an exit angle from the guide channel 142 at any angle as determined by formation characteristics and other variables. For example, the guide channel 142 may be configured to produce an angled channel in any range from about 5 degrees to close to 90 degrees relative to a central axis of the guide body 140.

[0027] Referring now to Figure 4, cutting device 120 in accordance with one or more embodiments of the present disclosure is shown. The cutting device 120 is inserted through the guide channel 142 (shown in Figure 3) of the guide body 140 to allow the cutting device 120 to bore through the casing wall and into the surrounding formation at a desired angle. The cutting device 120 may include a bearing section including, for example, bearing sleeves 122 and 124. The bearing sleeves 122 and 124 may be an upper adjustable non-rotating bearing sleeve 122 and a lower adjustable non-rotating bearing sleeve 124, which may be separated by a spacer section 128, for example an adjustable variable spacer section 128. The upper bearing sleeve 122 may be retained by top bearing retainers 121 and 123. Likewise, the lower bearing sleeve 124 may be retained by bottom bearing retainers 125 and 126. The distance between the upper and lower bearings 122 and 124 may be varied. In addition, diameters of the upper and lower bearings 122 and 124 may be varied.

[0028] The cutting device 120 may include a cutter 132, for example a bull nose-type tungsten cutter or other similar cutters known to those skilled in the art connected to the main body by a bit shaft of variable length and securing sleeve 130. In some embodiments, the cutter may be formed form a high speed steel or other metallurgically compatible materials. The securing sleeve 130 may be secured by a set screw type locking mechanism (not shown) or similar locking mechanism. With the adjustable length of the spacer 128 between the bearing sleeve 122 and 124 contact points, the bottomhole assembly can be adjusted to have an optimized cutter length ("AL"), such that the path taken by the cutter 132 through the guide channel 142 provides that the cutter 132 cuts directly and only into the casing sidewall and avoids cutting into any part of the guide channel 142. When present, as in the embodiment of Figure 4, the diameters of the bearing sleeves 122 and 124 of the spacer section 128 may also be adjusted to have such an optimized cutter length ("AL").

[0029] Referring now to Figure 5, calculating an optimized cutter length (AL) between the upper and lower bearing sleeves 122 and 124 includes input of known tool parameters for a given tool. Therefore, given these known inputs, for any size tool, the cutter length (AL) may be optimized such that the cutter 132 (Figure 4) exiting the guide channel 142 cuts directly and only into the casing sidewall and avoids contacting any part of the guide channel 142. For purposes of this application, the optimized cutter length (AL) is measured from the axially opposed faces 90 and 92 of the bearing sleeves 122 and 124, respectively, as shown in Figure 5. The known tool parameters include:

$\mathbf{ID_{gst}}$ = Inner diameter of guide channel
$\mathbf{OD_{cut}}$ = Cutter outer diameter
$\mathbf{R_c}$ = Radius of curvature of guide channel

[0030] A first radius (R_1) is calculated using the following equation:

$$R_1 = R_c + ID_{gst}$$

[0031] A second radius (R_2) is calculated using the following equation:

$$R_2 = R_c + OD_{cut}$$

[0032] Finally, an optimized cutter length (AL) is calculated using the following equation:

$$AL = 2 * \left[\sqrt{\left(R_2{}^2 - R_1{}^2\right)} \right]$$

[0033] In certain embodiments, the cutting device 120 and the hydraulic jet 102 may be separate tools that are run and retrieved in separate runs into the wellbore. For example, one or more cuts using a cutting device 120 may be performed in a single run. Next, one or more formation penetrating jet runs using a hydraulic jet 102 may be performed in a single run.

[0034] In other embodiments, the cutting device 120 and hydraulic jet 102 may be incorporated into a single tool or bottomhole assembly which accomplishes both casing cutting and multi-directional hydraulic boring, where the casing cutting and boring may be performed simultaneously or sequentially during one or more trips into the wellbore.

[0035] The following description is illustrative of methods of using the bottomhole assembly described above in accordance with one or more embodiments of the present disclosure. The guide body 140 may first be inserted into the casing and set at a desired depth in the wellbore. The guide body 140 may be locked in the casing by the expanding locking dogs 144 to position the tool eccentrically flush to the casing wall at the point of exit of guide channel 142 and lock the tool. The locking dogs may be hydraulically, electrically, pneumatically, or manually expanded, such as by, for example, a ball-drop mechanism.

[0036] The cutting device 120 may be then inserted into the wellbore and the cutter 132 may be guided by the guide channel 142 within the guide body 140 and into contact with the casing wall at a desired angle. The cutter 132 is attached to a 360 degree flexible drive shaft that may be operated hydraulically, pneumatically, or electrically to rotate the cutter and bore a hole through the casing wall and into the adjacent formation. The hydraulic, pneumatic, or electric motor may be fed into the wellbore by use of standard coil tubing, small drilling tubes, or rods. The cutter 132 may continue to bore past the casing wall and into the formation to provide a pilot bore in the formation past the casing wall into which the hydraulic jet and centralizers may be inserted.

[0037] The cutting device 120 may be retrieved from the wellbore and the hydraulic jet 102 may be inserted through the drilled hole in the casing and into the formation. The hydraulic jet 102 may be centered within the bore in the formation by the circumferential jet stream from the hydraulic centralizers 110. Forward-facing jet nozzles 104 and rearward-facing jet nozzles 106 of the hydraulic jet 102 may be arranged at predetermined angles to create multiple angled laterals through the formation in multiple directions. The forward- and rearward-facing jet nozzles 104 and 106 may be pressurized to provide a high pressure fluid blast into the formation to form multiple angled laterals in the formation, as was shown in Figure 1.

[0038] Advantageously, embodiments of the present disclosure provide a bottomhole assembly that is capable of producing an extensive drainage pattern of multi-angle and multi-directional penetrations that allows for the connection of any and all fractures, fissures, cavities, and other porosity locations in the producing and adjacent non-penetrated reservoir sections to be connected and thereby draining the in-situ fluids and gases to be extracted at a higher rate and improved recovery rate. The bottomhole assembly has hydraulic power penetration and hydraulic stabilization power that allows for faster and deeper penetration while controlling the angle and direction.

Claims

1. A drilling assembly (100) comprising:

a hydraulic jet (102) disposed on a downhole end of a fluid line (108); and
one or more multi-directional jet nozzles (104, 106) on the hydraulic jet (102) in multiple angular orientations relative to a central axis of the hydraulic jet (102),
wherein the one or more multi-directional jet nozzles (104, 106) provide fluid pressure to penetrate a formation (5) and cut one or more angular channels (12).

2. The drilling assembly (100) of claim 1, further comprising one or more hydraulic centralizers (110) disposed along a length of the fluid line (108) to centralize the hydraulic jet (102).

3. The drilling assembly (100) of claim 2, wherein the one or more hydraulic centralizers (100) include a plurality of radial jet nozzles (112) to provide a circumferential jet stream radially outward.

4. The drilling assembly (100) of claim 3, wherein the radial jet nozzles (112) are evenly spaced about a circumference of the hydraulic centralizers (100).

5. The drilling assembly (100) of claim 3, wherein the radial jet nozzles (112) are unevenly spaced about a circumference of the hydraulic centralizers (100).

6. The drilling assembly (100) of any of claims 1-5, wherein the one or more multi-directional jet nozzles (104, 106) are configured having various diameters.

7. The drilling assembly (100) of any of claims 1-6, wherein a jet size of the one or more multi-directional jet nozzles (104, 106) is adjustable downhole.

8. A cutting device (120) comprising:

a cutter (132) disposed on an end thereof;
a spacer section (128) proximate to the cutter (132); and
a guide channel (142) having a radius of curvature (143),
wherein a length of the spacer section (128) corresponds with the guide channel radius of curvature (143) to create a particular cutter path angle through a casing wall.

9. The cutting device (120) of claim 8, wherein the guide channel (142) has a radius of curvature to provide an exit angle therefrom of between about 5 degrees and 90 degrees relative to a central axis of the cutting device (120).

10. The cutting device (120) of claim 8 or claim 9, wherein the spacer section (128) comprises at least two bearing sleeves (122, 124) located axially on each end of the spacer section (128).

11. The cutting device (120) of claim 10, wherein the at least two bearing sleeves (122, 124) are non-rotating.

12. The cutting device (120) of any of claims 8-11, wherein the guide channel (142) is within a guide body (140) de-centered within a wellbore.

13. The cutting device (120) of any of claims 8-12, wherein the cutter (132) comprises a bull nose type high speed steel or tungsten cutter.

14. A bottomhole assembly comprising the drilling assembly (100) of any of claims 1-7 and the cutting device (120) as any of claims 8-13.

15. A method of drilling a formation, the method comprising:

inserting, into a formation channel, a hydraulic jet (102) comprising one or more multi-directional jet nozzles (104, 106);
providing high pressure fluid through the multi-directional jet nozzles (104, 106); and
cutting one or more angular channels (12) through the formation (5).

16. The method of claim 15, further comprising:

traversing a cutter (132) along a guide channel (142) having a radius of curvature (143),
providing a spacer section (128) proximate to the cutter (132), wherein the spacer section (128) has a length that corresponds with the radius of curvature (143) of the guide channel (142); and
cutting one or more holes through a wellbore casing.

17. The method of claim 16, further comprising running the cutter (142) and the hydraulic jet (102) into the wellbore casing in a single trip.

18. The method of claim 16 or claim 17, further comprising de-centering the guide channel (142) within the wellbore casing with a plurality of spring-loaded pads (144).

19. The method of any of claims 15-18, further comprising centralizing the hydraulic jet (102) in the formation channel with a circumferential jet stream from one or more hydraulic centralizers (110).

20. The method of any of claims 15-19, further comprising orienting the one or more multi-directional jet nozzles (104, 106) in one or more angular directions.

21. The method of any of claims 15-20, further comprising adjusting a size of the one or more multi-directional jet nozzles (104, 106).

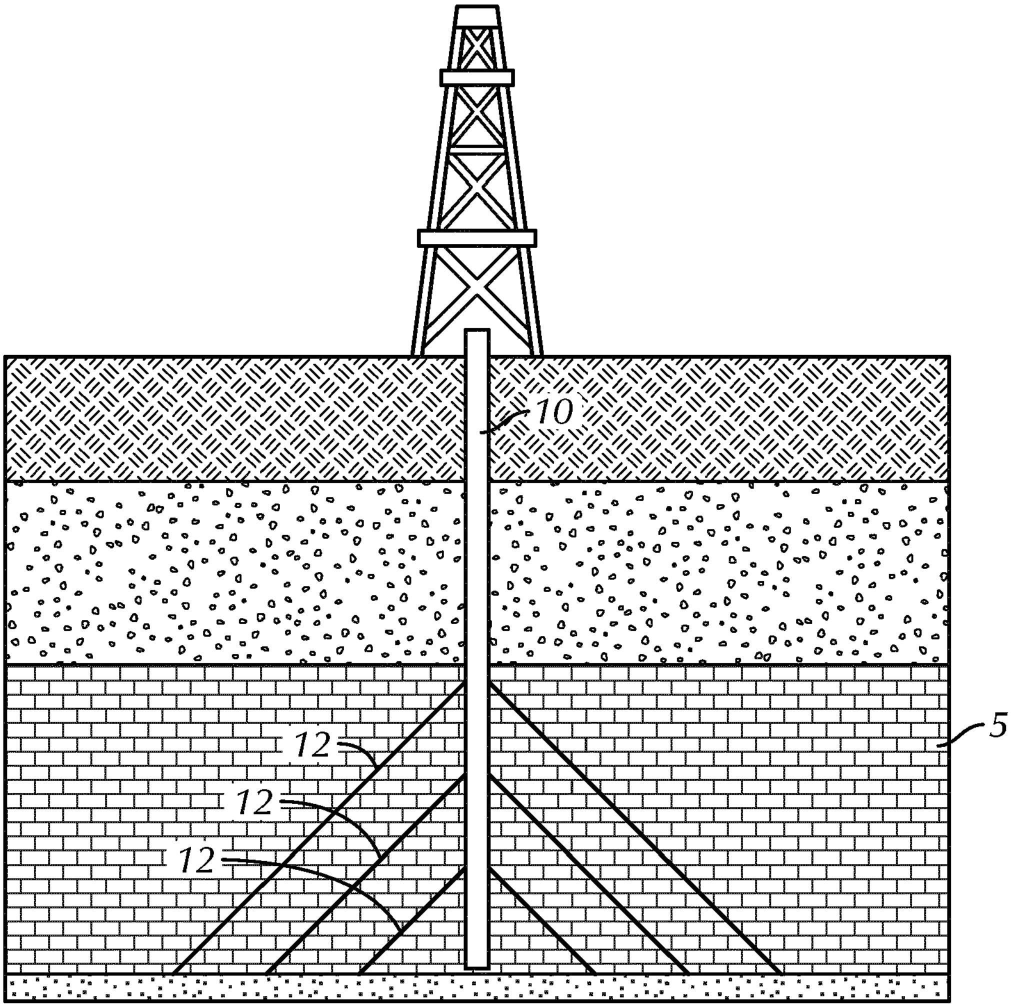
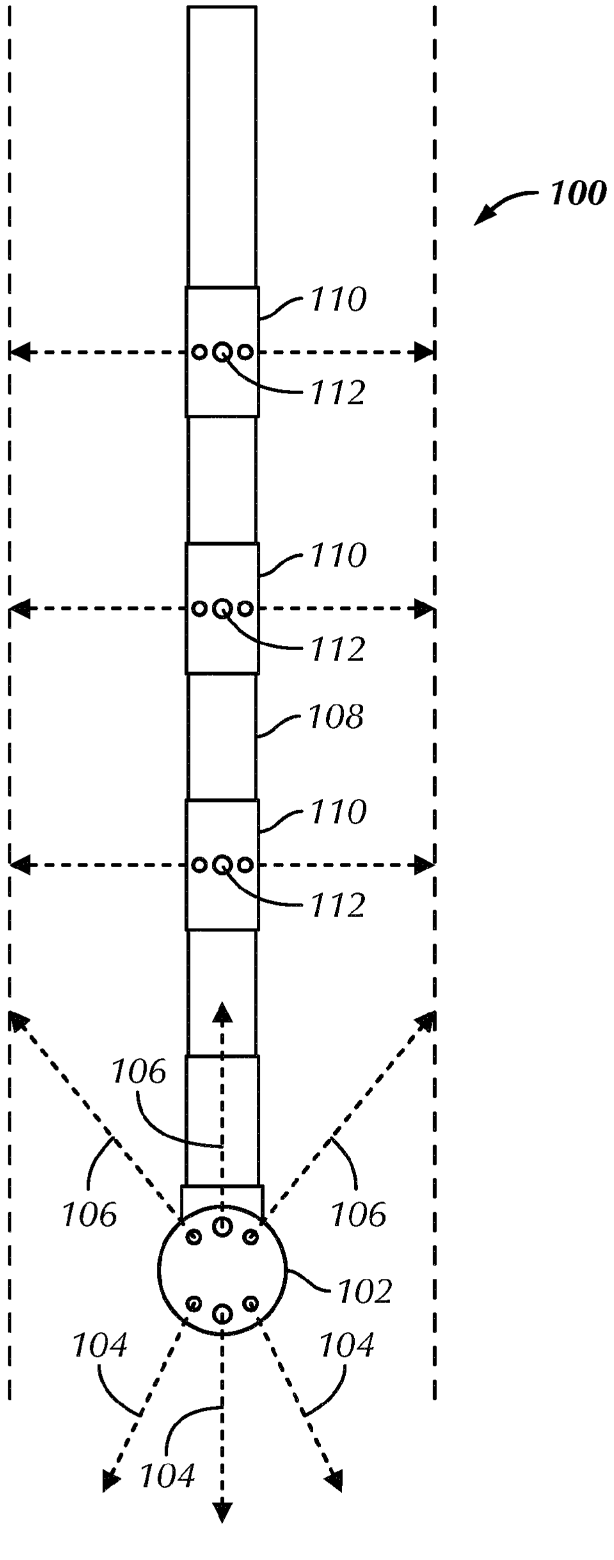


FIG. 1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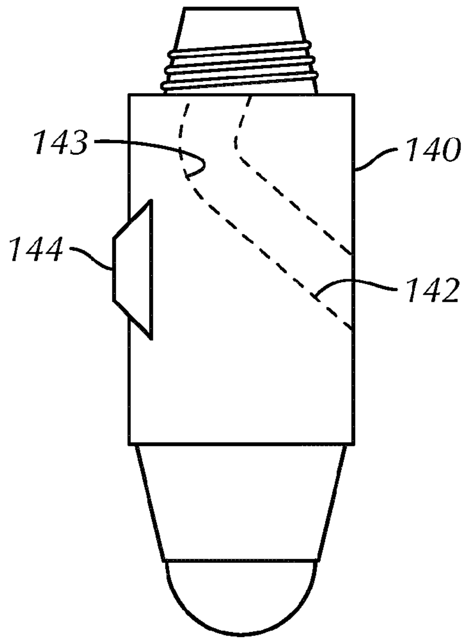
104

FIG. 2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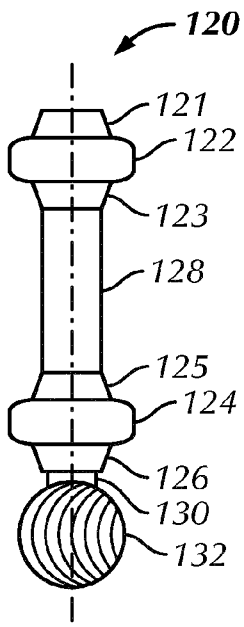
144
142

FIG. 3


120
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124
126
130
132

FIG. 4

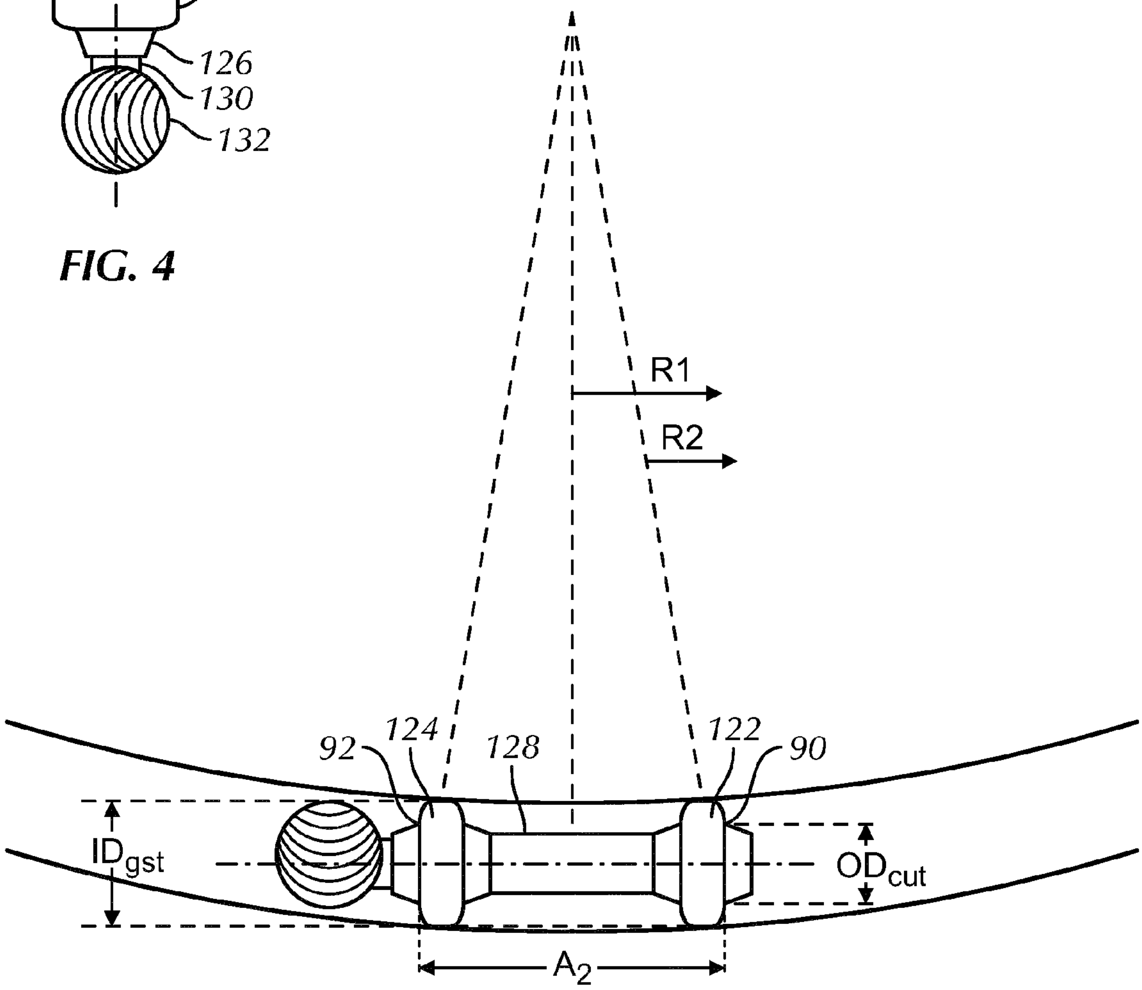
R1
R2
92
124
128
122
90
ID gst
OD cut
A2

FIG. 5