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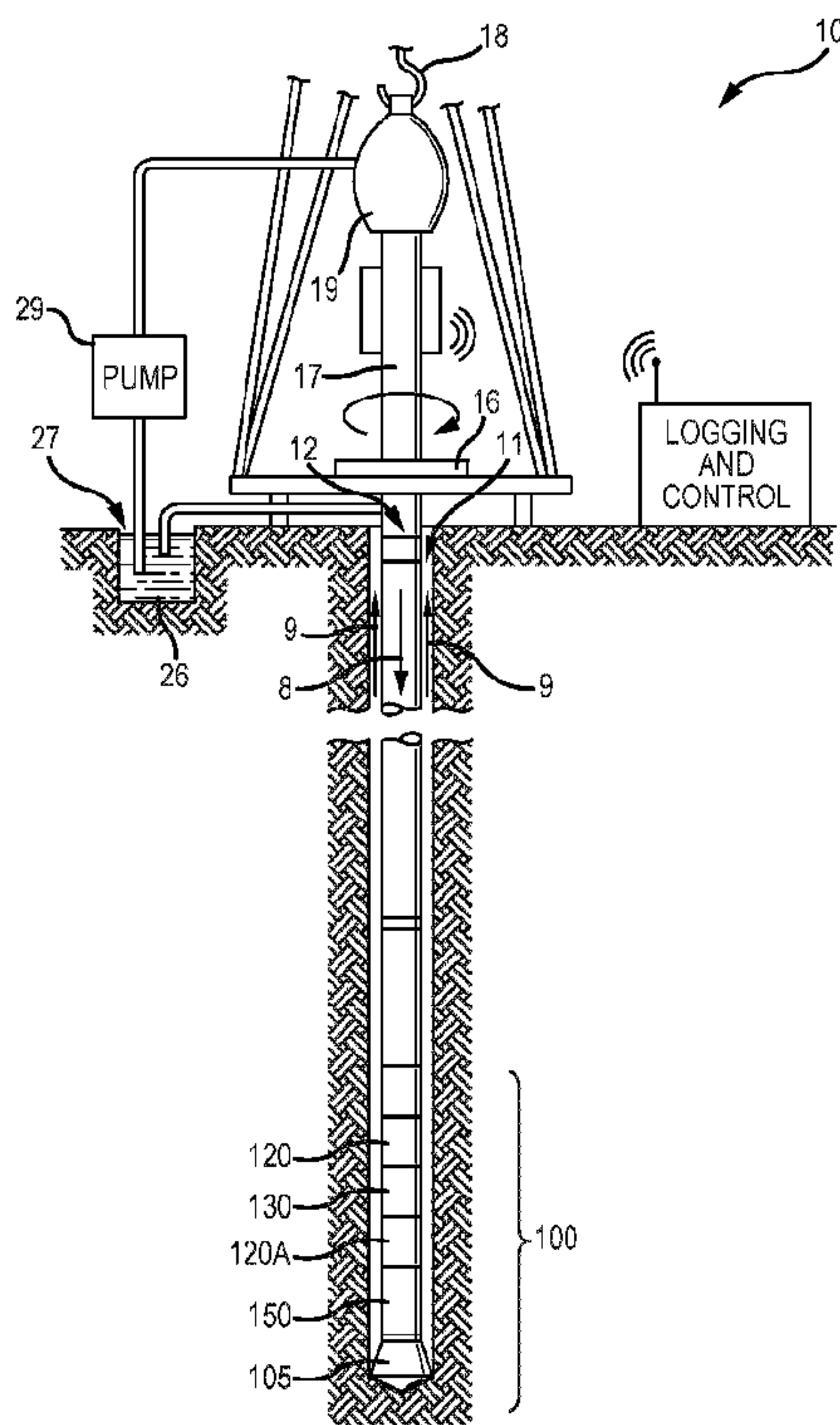


FIG. 1

(57) Abrégé/Abstract:

A bottomhole assembly for performing a wellbore operation comprising a plurality of full-gauge components that are each radially expandable and retractable between respective first positions and respective second positions, wherein the first positions each have a diameter which is substantially the same as that of the wellbore and wherein the second positions each have a diameter which is substantially smaller than that of the wellbore. The plurality of full-gauge components comprise a full-gauge drill bit and one or more full-gauge stabilizers. The bottomhole assembly may further comprise a rotary steerable system and/or a motor.

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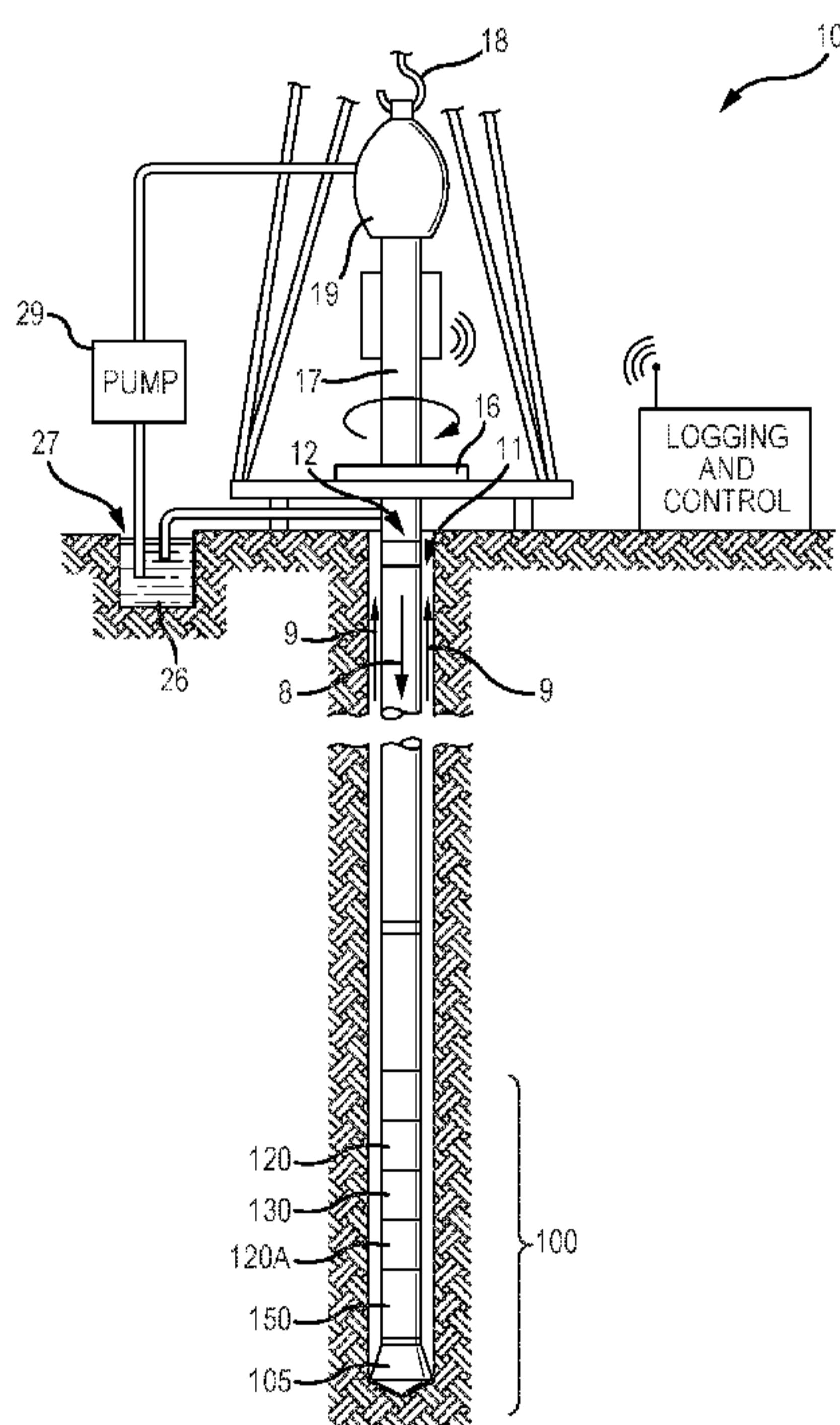
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FIG. 1

(57) **Abstract:** A bottomhole assembly for performing a wellbore operation comprising a plurality of full-gauge components that are each radially expandable and retractable between respective first positions and respective second positions, wherein the first positions each have a diameter which is substantially the same as that of the wellbore and wherein the second positions each have a diameter which is substantially smaller than that of the wellbore. The plurality of full-gauge components comprise a full-gauge drill bit and one or more full-gauge stabilizers. The bottomhole assembly may further comprise a rotary steerable system and/or a motor.

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BOTTOMHOLE ASSEMBLY

BACKGROUND

5 Embodiments of the present disclosure relate to a bottomhole assembly (BHA) for performing a wellbore operation and more particularly but not by way of limitation to a BHA comprising a drill bit and a stabilizer that are both radially expandable and retractable.

10 A borehole is often drilled in the ground for the extraction of a natural resource such as ground water, brine, natural gas, or petroleum. Such a borehole is also often referred to as a wellbore.

15 A bottomhole assembly (BHA) comprises the lower portion of the drillstring used in drilling a wellbore, and it generally comprises, from the distal end to the surface, one or more of the following, a drill bit, a bit sub, stabilizers, drill collars, heavy-weight drillpipe, jarring devices and crossovers for various threadforms. The BHA provides weight-on-bit (WOB) for the drill bit to break the rock, survive a hostile mechanical environment and provide the driller with directional control of the well. The BHA may also include a mud motor, directional drilling and measuring equipment, measurement-while-drilling (MWD) tools, logging-while-drilling (LWD) tools and/or other specialized devices.

25 A drill bit is normally the bottom most component of a BHA and thus the bottom most component of the drillstring and it has a great impact on the speed of drilling as well as the longevity of drilling. When the drill bit becomes dull or stops making progress for other reasons, it must be taken out of the wellbore, a process referred to as tripping, and replaced, which increases costly rig time. Most drill bits work by scraping and/or crushing the rock. The drill bit may be rotated by the drillstring or a downhole motor to produce the scraping and/or crushing of the rock. There are primarily two types of drill bits used in the oilfield, fixed-cutter bits and roller-cone bits.

30 A stabilizer stabilizes a BHA in the wellbore in order to create a smooth borehole and reduce vibrations. The BHA may comprise a hollow cylindrical body and stabilizing blades, both made of high-strength steel. The blades may be either straight or spiraled, and need to be wear resistant. Several types of drilling stabilizers are used in the oilfield today, including integral stabilizers, replaceable sleeve stabilizers, and welded blades stabilizers. Usually 2 to 3 stabilizers are fitted into a BHA, including one near-bit stabilizer which is placed just above the drill bit and one or two string stabilizers which are placed among the

drill collars, steering tools such as motors or rotary-steerable-tools, and MWD and LWD tools.

In general, bottomhole assemblies contain components which have substantially the same diameter as the hole being drilled. This is because, in order to drill a hole of a particular diameter, there must be components of the drillstring that have substantially the same diameter as the hole being drilled. In particular, the drill bit must be of substantially the same diameter as the nominal hole size, and in order to stabilize the BHA significantly, there must be stabilizers that are close to hole gauge.

When drilling a high-angle, *i.e.* horizontal or close to horizontal, well, it has long been recognized that a bed of drill-cuttings develops behind, and also underneath, the bottomhole assembly (BHA). When the drillstring is withdrawn from the wellbore/tripped from the wellbore, the larger diameter components of the BHA, such as stabilizers and the drill bit must plough through this cuttings bed. Often, this will result in a dune forming above the BHA or its larger components, which can build up to a size which increases the tension that must be applied to the drillstring to pull the BHA out of the hole, and in extreme cases blocks the hole impeding further progress of the drillstring out of the hole. In order to avoid problems in removing the drillstring from the hole, and also re-entering drilled hole, extra time must be taken, for instance by pumping and rotating while pulling out, which can also have detrimental effects on hole quality due to rotational impacts of the bit and BHA with the borehole wall.

SUMMARY OF THE DISCLOSURE

The present disclosure seeks to overcome the drawbacks of the known bottomhole assemblies.

In a first aspect, embodiments of the present disclosure address these problems by providing a bottomhole assembly for performing a wellbore operation that is configured to expand and contract radially. The bottomhole assembly comprises a plurality of full-gauge components that are each radially expandable and retractable between respective first positions and respective second positions, wherein the first positions each have a diameter which is substantially the same as that of the wellbore and the second positions each have a diameter which is smaller than that of the wellbore. The plurality of full-gauge components comprise a drill bit that is radially expandable and retractable between the first

position and the second position and a first stabilizer that is radially expandable and retractable between a respective first position and second position.

5 In the present disclosure, 'substantially the same' is taken to include exactly the same and substantially the same.

10 A component having a diameter which is the same or substantially the same as that of the wellbore to be drilled is called a full-gauge component. For example, a full-gauge component for a wellbore having a diameter up to approximately 17 inches may have a diameter that is between 0 and 3/8 inch smaller than that of the wellbore, and preferably 1/8 to 1/4 inch smaller.

15 By contrast, an under-gauge component has a diameter which is substantially smaller than that of the wellbore to be drilled. For example, a component with a diameter of 6 1/2 inches for a wellbore with a diameter of 6 7/8 inches is an under-gauge component. In general, an under-gauge component for a wellbore having a diameter up to approximately 17 inches may be between 3/8 and 1 inch smaller than that of the wellbore, and preferably 1/2 to 3/4 inch smaller. An under-gauge component may also be more than 1 inch smaller than that of the wellbore.

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Typically, the absolute difference, rather than relative or percentage difference, between the diameter of a component and the diameter of the wellbore dictates whether the component is full-gauge or under-gauge. However for large and very large boreholes *e.g.* those having a diameter greater than 17 inches, the absolute difference between the diameter of a component and the diameter of the wellbore required for the component to be defined as under-gauge may be slightly larger than that for small and normal sized holes.

25

30 In the present application, a full-gauge component is defined as a component with a radial position which has a diameter that is the same or substantially the same as that of the wellbore. An under-gauge component is defined as a component with a maximum diameter that is substantially smaller than that of the wellbore.

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A full-gauge component may have a maximum diameter that is the same or substantially the same as that of the wellbore. For example, a full-gauge stabilizer is a stabilizer with a maximum diameter that is substantially the same as that of the wellbore. An under-gauge stabilizer is a stabilizer with a maximum diameter that is substantially smaller than that of the wellbore.

Alternatively, a full-gauge component may have a position with a diameter which is the same or substantially the same as that of the wellbore, while having an additional position with a diameter which is substantially larger than that of the wellbore. For example, a drill
5 bit may have an additional position with a diameter which is substantially larger than that of the wellbore, so that the drill bit can also act as an under-reamer or reamer to enlarge the wellbore.

Accordingly, the first aspect provides bottomhole assembly comprising a full-gauge drill
10 bit with a maximum diameter which is the same or substantially the same as that of the wellbore. The drill bit is configured so it can be retracted to an under-gauge position for ease of running through the wellbore, especially in directional drilling. Similarly, the BHA also includes a full-gauge stabilizer with a maximum diameter which is the same or substantially the same as that of the wellbore. The stabilizer too can be retracted to an
15 under-gauge position for ease of running through the wellbore. The under-gauge position may be approximately $\frac{1}{4}$ inch smaller in diameter than that of the full-gauge position. More preferably, the under-gauge position is between approximately $\frac{1}{8}$ inch and approximately $\frac{3}{8}$ inch smaller in diameter than that of the full-gauge position.

20 The diameter of the first position of the drill bit may be substantially the same as that of the first position of the first stabilizer, and the diameter of the second position of the drill bit may be substantially the same as that of the second position of the first stabilizer. However, this is not essential, and the diameter of the first position of the drill bit may be different from that of the first position of the first stabilizer, and/or the diameter of the second
25 position of the drill bit may be different from that of the second position of the first stabilizer.

The first stabilizer may comprise three or more radial positions. In addition to its first position and second position which allow the BHA to drill when needed and to run through
30 the wellbore easily when it's not drilling, the first stabilizer may comprise one or more additional radial positions aimed at adjusting the BHA tendency while drilling, thus help control the direction of drilling. Typically, three positions are provided for this purpose so that the BHA can be directed to drill float, up or down. More positions may be provided to better control the direction of drilling.

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Furthermore, each additional radial position may have a respective diameter which is substantially smaller than that of the first diameter. Some or all additional radial positions may be substantially smaller than the second position.

- 5 One or more positions of the first stabilizer may serve both purposes, thus acting as the first or the second position allowing the BHA to drill when needed and to run through the wellbore easily when not drilling, and at the same time acting as an additional position to provide directional guidance.
- 10 In some embodiments, the first stabilizer has two additional positions, *i.e.* a total of four positions. In some other embodiments, the first stabilizer has three additional positions, *i.e.* a total of five positions.

Optionally, the BHA also comprises a second stabilizer. The second stabilizer may be not
15 radially expandable and retractable, wherein the second stabilizer has a diameter which is substantially smaller than that of the wellbore. Alternatively, the second stabilizer may be radially expandable and retractable between its first position and its second position, wherein each of its first and second positions has a respective diameter which is substantially smaller than that of the wellbore. Alternatively, the second stabilizer may be
20 radially expandable and retractable between its first position and its second position, wherein its first position has a diameter which is substantially the same as that of the wellbore, and wherein its second position has a diameter which is substantially smaller than that of the wellbore.

25 Therefore the BHA may comprise a second stabilizer with a maximum diameter which is substantially smaller than that of the wellbore. If such a second stabilizer is provided, the second stabilizer may be retractable or not retractable. If the second stabilizer is retractable, it may comprise two or more radial positions. Additional positions may be provided to help adjust the BHA tendency thus help control the direction of drilling.

30 In some embodiments, the second stabilizer comprises a total of three radial positions. For example, if the maximum diameter of the second stabilizer is already small enough for passing through the wellbore easily, then three positions may be provided solely for directional control so that the BHA can drill straight, up or down. Alternatively, if the
35 maximum diameter of the second stabilizer is not small enough for passing through the wellbore easily, then it is possible to provide a maximum position, a retractable position,

and one or more further retracted positions for directional control, while using the retracted or minimum position for ease of running through the wellbore.

5 In some embodiments, the second stabilizer has three radial positions for directing the BHA to drill straight, up or down. One or more positions of the second stabilizer may server both purposes, e.g. providing a retracted position for running through the wellbore as well as acting as a position for directional control. In some other embodiments, it comprises a total of four or five radial positions. For example, three positions may be provided for directional control while an additional one or two positions may be used for ease of running through
10 the wellbore.

Alternatively, the BHA may comprise a second stabilizer with a maximum diameter which is the same or substantially the same as that of the wellbore. If such a second full-gauge stabilizer is provided, the second stabilizer must be radially retractable to an under-gauge
15 position for ease of running through the wellbore. Optionally such a second stabilizer may comprise one or more additional radial positions e.g. for directional control. The additional positions may be substantially smaller than its first position.

Optionally, the BHA also comprises a third stabilizer. The third stabilizer may be radially
20 expandable and retractable between its first position and its second position, wherein its first position has a diameter which is substantially the same as that of the wellbore, and wherein its second position has a diameter which is substantially smaller than that of the wellbore.

Accordingly, the invention may comprise a third stabilizer whose maximum diameter is the
25 same or substantially the same as that of the wellbore. If provided, the third stabilizer must be retractable to an under-gauge position for ease of running through the wellbore.

One or more additional, i.e. fourth, fifth and etc., stabilizers may be provided. If provided, additional stabilizers may be full-gauge stabilizers or under-gauge stabilizers. If additional full-gauge stabilizers are provided, they must be retractable to an under-gauge position for
30 ease of running through the wellbore.

Furthermore, the BHA may comprise one or more further components in addition to those specifically mentioned in the present disclosure. Further components may be full-gauge components or under-gauge components or a mixture thereof. If additional full-gauge
35 components are provided, they must each be retractable to a respective under-gauge position for ease of running through the wellbore.

The expandable drill bit may comprise a drill bit and a near bit reamer, wherein the drill bit may be a roller cone bit or a fixed cutter bit. Such an arrangement makes use of conventional drill bits and conventional near bit reamers, which are readily available. Thus, it's more convenient and cheaper to provide a BHA with such an expandable drill bit.

5

The near bit reamer may be capable of under-reaming. Accordingly, it may be a near bit reamer, a near bit under-reamer, or a near bit reamer capable of both reaming and under-reaming. In a conventional BHA, the drill bit has a diameter which is substantially the same as that of the wellbore so that it can drill a wellbore of the same diameter, and the near bit reamer has a maximum diameter which is larger than that of the wellbore so that it can be expanded and used to enlarge the wellbore to a larger diameter. By contrast, if a conventional drill bit and a conventional near bit reamer are provided in accordance with embodiments of the present disclosure, the drill bit has a diameter which is substantially smaller than that of the wellbore so that, when the BHA is retracted, it can run through the wellbore more easily especially during directional drilling, and the near bit reamer has a maximum diameter that is substantially the same as that of the wellbore so that it can drill a wellbore of the same diameter. Accordingly, the near bit reamer or under-reamer of the present invention, when expanded, performs the function of a drill bit in conventional applications. Furthermore, in embodiments of the present disclosure the near bit reamer can be retracted to an under-gauge position for ease of running through the wellbore.

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In some embodiments, the expandable drill bit may comprise a fixed cutter drill bit and a near bit reamer or near bit under-reamer.

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The drill bit may comprise three or more radial positions. In addition to its first and second positions, one or more additional radial positions may be provided on the drill bit so that the drill bit can act as a conventional reamer or under-reamer to enlarge the wellbore. Accordingly, the additional radial positions may have a diameter which is substantially larger than that of its first position and thus larger than that of the wellbore.

30

In some embodiments, the expansion and retraction of the drill bit and each of the stabilizers are controllable remotely, so that their actions underground can be controlled from surface level.

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In some embodiments, the expansion and retraction of the drill bit and each of the stabilizers are controllable independently. As a result, each component can be expanded and retracted separately and independently of the other components. This provides flexibility to the system and has many practical applications. This allows removing a restriction in the

wellbore using an expanded drill bit while protecting a retracted stabilizer or retracted stabilizers. This also allows identification of the location of a restriction in the wellbore by expanding and retracting individual components sequentially. This may also allow independent control of a retractable stabilizer with additional radial positions for directional control so that directional control can be achieved separately and independently of retraction for ease of running through the wellbore.

In some embodiments, the expansion and retraction of the drill bit and each of the stabilizers are controllable using a wired drill pipe. A wired drill pipe has a cable embedded in it, so it can carry data and control signals from the drill bit to the surface and from the surface to the drill bit much faster than with mud pulses. Furthermore, this means data and control signals can be transmitted to and from the BHA independently of whether fluid is circulating through the system.

Although the control of whether elements expand or contract may be under the control of an electrical system such as that commanded by a wired drill pipe, the actual mechanism of movement may either be electro-mechanical, or hydraulic, for example utilizing the pressure difference between the interior and exterior of the BHA while fluid is flowing, with the application of the pressure controlled by means such as electro-mechanical pilot valves.

The expansion and retraction of the drill bit and each of the stabilizers may be actuatable using pressure changes. The expansion and retraction of the drill bit and each of the stabilizers may be controllable remotely and independently using a wired drill pipe, ball drop or dart drop, electromagnetic telemetry, or thru-earth telemetry.

Though wired pipe may be used, other means of controlling the expansion and contraction of BHA elements are also possible. Pressure activated means such as the use of ball-drops or dart-drops, either controlling elements individually or together can be used, as can the use of pressure cycling where one pressure cycle opens the elements and a subsequent cycle closes them.

Additionally other means are possible for communicating with a downhole electro-mechanical system, such as the use of pressure pulses or cycles, or the sending of electromechanical or acoustic energy through the earth, received by an appropriate antenna, hydrophone or motion-sensitive system in the BHA.

In a second aspect, a BHA in accordance with embodiments of the present disclosure may include a rotary steerable system. A rotary steerable system typically is designed to drill directionally with continuous rotation from the surface, eliminating the need to slide a steerable motor. Rotary steerable systems typically are deployed when drilling directional,
5 horizontal, or extended-reach wells. Alternatively, the BHA may include a motor, or a motor and a rotary steerable system.

In a further aspect, embodiments of the present disclosure provide a method of performing a wellbore operation using the bottomhole assembly, the method comprising: retracting
10 each full-gauge component of the bottomhole assembly, whose respective first position has a diameter which is substantially the same as that of the wellbore, to its respective second position; running the bottomhole assembly from the up-hole side to the down-hole side of the well; expanding each full-gauge component to its respective first position; and drilling the wellbore.

15 Accordingly, after drilling the BHA can be pulled out of the wellbore more easily once all full-gauge components are retracted and thus reducing the maximum diameter of the BHA to substantially smaller than that of the wellbore.

20 In another aspect, embodiments of the present disclosure provides a method of performing a wellbore operation using the bottomhole assembly, the method comprising: retracting each full-gauge component of the bottomhole assembly, whose respective first position has a diameter which is substantially the same as that of the wellbore, to their respective second position; and running the bottomhole assembly from the down-hole side to the up-hole side
25 of the well.

Accordingly, the BHA can run into the wellbore more easily once all full-gauge components are retracted and thus reducing the maximum diameter of the BHA to substantially smaller than that of the wellbore. Once downhole, all full-gauge components
30 of the BHA can be expanded to full-gauge so that a wellbore of the same diameter can be drilled further.

In another aspect, embodiments of the present disclosure provide a method for removing a restriction in a wellbore using the bottomhole assembly, the method comprising: expanding
35 the drill bit to its first position; retracting each full-gauge stabilizer of the bottomhole assembly, whose respective first position has a diameter which is substantially the same as

that of the wellbore, to its respective second position; running the bottomhole assembly from the up-hole side to the down-hole side of the well; and removing the restriction.

Therefore the expanded drill bit can remove the restricting while the retracted stabilizer or
5 retracted stabilizers are protected.

In another aspect, embodiments of the present disclosure provide a method for locating a restriction in a wellbore using the bottomhole assembly, the method comprising: retracting the drill bit to its second position; retracting each full-gauge stabilizer of the bottomhole
10 assembly, whose respective first position has a diameter which is substantially the same as that of the wellbore, to its respective second position; and identifying the location of the restriction.

Accordingly, each full-gauge component is retracted sequentially so that the location of the
15 restriction in the wellbore can be identified more precisely.

It is understood that any or all of the above features of the disclosure can be combined in any combination to provide advantages which will become further apparent on reading the following detailed description.
20

In particular, the above methods can be combined freely in practice. For example, full-gauge components may be retracted, run into the wellbore and then expand to locate a restriction of the wellbore and/or remove the restriction.

Furthermore, the steps of each method can be performed in any order. For example, to locate a restriction in a wellbore, the drill bit and each stabilizer can be retracted in any order to identify the location of the restriction. In another example, each full-gauge stabilizer may be retracted before or after the drill bit is expanded in the method to remove a restriction.
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30

BRIEF DESCRIPTION OF THE DRAWINGS

The disclosure will now be described, by way of example only, with reference to the accompanying drawings in which:
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Figure 1 shows a wellsite system in which embodiments of the present disclosure can be employed.

Figure 2 is a schematic partial cross sectional view of a bottomhole assembly within a wellbore showing full-gauge components in their retracted position.

- 5 Figure 3 shows a schematic partial cross sectional view of a bottomhole assembly within a wellbore showing full-gauge components in their expanded position.

DETAILED DESCRIPTION

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Referring now to the drawings, figure 1 illustrates a wellsite system in which embodiments of the present disclosure can be employed. The wellsite can be onshore or offshore. In this exemplary system, a borehole 11 is formed in subsurface formations by rotary drilling in a manner that is well known. Embodiments of the invention can also use directional drilling,
15 as will be described hereinafter.

15

A drill string 12 is suspended within the borehole 11 and has a bottomhole assembly 100 which includes a drill bit 105 at its lower end. The surface system includes platform and derrick assembly 10 positioned over the borehole 11, the assembly 10 including a rotary
20 table 16, kelly 17, hook 18 and rotary swivel 19. The drill string 12 is rotated by the rotary table 16, energized by means not shown, which engages the kelly 17 at the upper end of the drill string. The drill string 12 is suspended from a hook 18, attached to a traveling block (also not shown), through the kelly 17 and a rotary swivel 19 which permits rotation of the
25 drill string relative to the hook. As is well known, a top drive system could alternatively be used.

25

In the example of this embodiment, the surface system further includes drilling fluid or mud 26 stored in a pit 27 formed at the well site. A pump 29 delivers the drilling fluid 26 to the interior of the drill string 12 via a port in the swivel 19, causing the drilling fluid to
30 flow downwardly through the drill string 12 as indicated by the directional arrow 8. The drilling fluid exits the drill string 12 via ports in the drill bit 105, and then circulates upwardly through the annulus region between the outside of the drill string and the wall of the borehole, as indicated by the directional arrows 9. In this well known manner, the
35 drilling fluid lubricates the drill bit 105 and carries formation cuttings up to the surface as it is returned to the pit 27 for recirculation.

35

The bottomhole assembly 100 of the illustrated embodiment comprises a logging-while-drilling (LWD) module 120, a measuring-while-drilling (MWD) module 130, a rotary-steerable system and motor, and drill bit 105.

5 The LWD module 120 is housed in a special type of drill collar, as is known in the art, and can contain one or a plurality of known types of logging tools. It will also be understood that more than one LWD and/or MWD module can be employed, e.g. as represented at 120A. (References, throughout, to a module at the position of 120 can alternatively mean
10 a module at the position of 120A as well.) The LWD module includes capabilities for measuring, processing, and storing information, as well as for communicating with the surface equipment. In the present embodiment, the LWD module includes a pressure measuring device.

The MWD module 130 is also housed in a special type of drill collar, as is known in the
15 art, and can contain one or more devices for measuring characteristics of the drill string and drill bit. The MWD tool further includes an apparatus (not shown) for generating electrical power to the downhole system. This may typically include a mud turbine generator powered by the flow of the drilling fluid, it being understood that other power and/or battery systems may be employed. In the present embodiment, the MWD module includes one or
20 more of the following types of measuring devices: a weight-on-bit measuring device, a torque measuring device, a vibration measuring device, a shock measuring device, a stick slip measuring device, a direction measuring device, and an inclination measuring device.

A particularly advantageous use of the system hereof is in conjunction with controlled
25 steering or “directional drilling.” In this embodiment, a rotary-steerable subsystem 150 (Figure 1) is provided. Directional drilling is the intentional deviation of the wellbore from the path it would naturally take. In other words, directional drilling is the steering of the drill string so that it travels in a desired direction. Directional drilling is, for example, advantageous in offshore drilling because it enables many wells to be drilled from a single
30 platform. Directional drilling also enables horizontal drilling through a reservoir. Horizontal drilling enables a longer length of the wellbore to traverse the reservoir, which increases the production rate from the well. A directional drilling system may also be used in vertical drilling operation as well. Often the drill bit will veer off of a planned drilling trajectory because of the unpredictable nature of the formations being penetrated or the
35 varying forces that the drill bit experiences. When such a deviation occurs, a directional drilling system may be used to put the drill bit back on course.

A known method of directional drilling includes the use of a rotary steerable system (“RSS”). In an RSS, the drill string is rotated from the surface, and downhole devices cause the drill bit to drill in the desired direction. Rotating the drill string greatly reduces the occurrences of the drill string getting hung up or stuck during drilling. Rotary steerable
5 drilling systems for drilling deviated boreholes into the earth may be generally classified as either “point-the-bit” systems or “push-the-bit” systems.

In the point-the-bit system, the axis of rotation of the drill bit is deviated from the local axis of the bottomhole assembly in the general direction of the new hole. The hole is propagated
10 in accordance with the customary three point geometry defined by upper and lower stabilizer touch points and the drill bit. The angle of deviation of the drill bit axis coupled with a finite distance between the drill bit and lower stabilizer results in the non-collinear condition required for a curve to be generated. There are many ways in which this may be achieved including a fixed bend at a point in the bottomhole assembly close to the lower
15 stabilizer or a flexure of the drill bit drive shaft distributed between the upper and lower stabilizer. In its idealized form, the drill bit is not required to cut sideways because the bit axis is continually rotated in the direction of the curved hole. Examples of point-the-bit type rotary steerable systems, and how they operate are described in U.S. Patent Application Publication Nos. 2002/0011359; 2001/0052428 and U.S. Patent Nos.
20 6,394,193; 6,364,034; 6,244,361; 6,158,529; 6,092,610; and 5,113,953 all herein incorporated by reference.

In the push-the-bit rotary steerable system there is usually no specially identified mechanism to deviate the bit axis from the local bottomhole assembly axis; instead, the
25 requisite non-collinear condition is achieved by causing either or both of the upper or lower stabilizers to apply an eccentric force or displacement in a direction that is orientated with respect to the direction of hole propagation. Again, there are many ways in which this may be achieved, including non-rotating (with respect to the hole) eccentric stabilizers (displacement based approaches) and eccentric actuators that apply force to the drill bit in
30 the desired steering direction. Again, steering is achieved by creating non co-linearity between the drill bit and at least two other touch points. In its idealized form the drill bit is required to cut side ways in order to generate a curved hole. Examples of push-the-bit type rotary steerable systems, and how they operate are described in U.S. Patent Nos. 5,265,682; 5,553,678; 5,803,185; 6,089,332; 5,695,015; 5,685,379; 5,706,905; 5,553,679;
35 5,673,763; 5,520,255; 5,603,385; 5,582,259; 5,778,992; 5,971,085 all herein incorporated by reference.

Conventional bottom-hole assemblies comprise components which have substantially the same diameter as that of the hole being drilled. Particularly for high-angle and extended-reach wells such assemblies can be difficult to withdraw and re-insert.

5 The disclosure provides a bottom-hole assembly which has full-gauge components necessary for drilling a wellbore of a predetermined diameter, such as a drill bit and one or more stabilizers, while all of these full-gauge components of the BHA can be retracted radially to a substantially smaller diameter than that of the wellbore for running into the wellbore, pulling out of the wellbore, and for remediating wellbore condition.

10

Referring now to figure 2 which illustrates a BHA 100 in a wellbore 11 in its retracted form, where each component of the BHA has a respective diameter that is substantially smaller than that of the wellbore 11.

15 The wellbore 11 may or may not comprise casing and/or other protective layer. If casing is provided, the casing may or may not have been cemented in the space between the casing and formation.

20 The diameter of a wellbore in the present disclosure refers to the inner diameter of the wellbore. If casing is provided, the diameter of the wellbore refers to the inner diameter of the casing of the wellbore.

25 The BHA 100 comprises, from the up-hole side to the down-hole side, a first non-expandable section 30, a first expandable stabilizer 60, a second non-expandable section 40, a second expandable stabilizer 70, a third non-expandable section 50, and an expandable drill bit 105.

30 The first non-expandable section 30, the second non-expandable section 40, and the third non-expandable section 50 each comprises one or more non-expandable components including, but not limited to, drill collars, heavy-weight drillpipes, jarring devices, crossovers, bit subs, rotary steering tools, positive-displacement-motors such as mud motors, measurements-while-drilling tools, logging-while-drilling tools, directional drilling and measuring equipment and other specialized devices. The drill collars may be conventional drill collars or anything that can provide sufficient weight on bit.

35

The first non-expandable section 30 of the BHA 100 is connected to the end of the drillstring 12 so that the drillstring 12 can rotate the BHA 100 during drilling.

In this particular example, there are two expanding stabilizers 60 and 70, and an expanding drill-bit 105. The first stabilizer 60 is a full-gauge stabilizer with a maximum diameter which is substantially the same as that of the wellbore. The second stabilizer 70 is an under-gauge stabilizer with a maximum diameter which is substantially smaller than that of the wellbore. The drill bit 105 is a full-gauge drill bit with a maximum diameter which is substantially the same as that of the wellbore.

The technology necessary for expanding and retracting the drill bit 105 is well known and currently used in on-demand reamers such as the Smith Rhino Reamer. All full-gauge, or near full-gauge stabilizers 60 and 70 can be similarly actuated based on on-demand reamer technology, but possibly without embedded cutters.

The drill bit 105 and the stabilizers 60 and 70 of this example all have expandable blades that can slide out of their respective blade housing and be locked to their respective expanded positions, and can slide into their respective blade housing and be locked to their respective retracted positions. The expandable blades on the drill bit 105 may have embedded gauge cutters in them, as well as cutters on the leading edge, so that the drill bit 105 is more effective at drilling the wellbore, whereas the blades on the stabilizers 60 and 70 don't have embedded cutters in them as their main function is to stabilize the BHA during drilling.

Figure 3 shows the same BHA 100 in its expanded form with an expanded drill bit 81 and two expanded stabilizers 61 and 71. The first expandable stabilizer's blades 61a and 61b have now expanded and the first stabilizer 60 has become a full-gauge stabilizer 61, and the second expandable stabilizer blades 71a and 71b have converted the second stabilizer into an under-gauge stabilizer 71. Extra cutting blades 81a and 81b have expanded from the drill bit 81 and are locked in its expanded full-gauge position.

In this example, the under-gauge stabilizer 71 has a maximum diameter which is substantially smaller than that of the wellbore. However, it still needs to be retracted to an even smaller diameter for BHA to run through the wellbore sufficiently easily.

Figure 3 shows that the expandable parts of the stabilizers 61 and 71 and the drill bit 81 are axially smaller than the non-expandable parts. This is not an essential feature of the present disclosure. The expandable parts of these components may be axially longer or longer than

the respective non-expandable parts. In fact, the expandable parts can be of any shape and size.

5 There are two blades shown on each expandable component of the BHA 100 of this example. It is understood that radial expansion and retraction can be achieved using any number of blades and the number of blades is not an essential feature of the disclosure. Furthermore, the radial expansion and retraction of expandable components may be achieved using any other appropriate mechanism and different components may use different mechanisms.

10

The drill bit 81 provides a drilling function and a retracting/expandable function.

15

The drilling function of the drill bit 81 may be based on the technology of a conventional drill bit such as a roller cone bit or a fixed cutter bit. A roller cone bit typically comprises a plurality of rotating steel cones and each cone rotates on its own axis during drilling. A fixed cutter bit consists of a solid piece with no moving parts, and typical comprises a plurality of hard wearing cutters. Examples of fixed cutter bits include, but not limited to, natural diamond bits, polycrystalline diamond compact (PDC) bits, thermally stable polycrystalline diamond (TSP) bits, and hybrid bits.

20

The expandable function of the drill bit 81 may be provided by a conventional near bit reamer. A conventional near bit reamer may comprise PDC blades that can slide radially in and out of blade housing. Alternatively, a roller cone reamer may be used which comprises a plurality of roller cones that swing in and out around a pivot in order to provide retracted and expanded positions.

25

Thus, the drill bit 81 can be a combined drill bit and near-bit reamer as a one piece component or as two separate pieces of equipment. For example, a roller cone bit or a fixed cutter bit may be used with a conventional near bit reamer or they can be welded into one piece.

30

The expandable function allows the drill bit to be retracted so that when run into hole there are no cutters at full-gauge, but after expansion the blades cover the full hole diameter. The expandable function of the drill bit may be provided by a separate near bit reamer or integral expandable elements on the same component. For example, the expandable drill bit can be provided by a conventional drill bit with additional expandable elements, such as additional blades similar to those of a conventional near-bit reamer. Alternatively, the drill bit itself

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may be provided with hinged parts that can swing in and out around a pivot in order to retract and expand.

5 Any other suitable expansion and retraction mechanisms may be used. For example, the drill bit 81 may comprise expandable blades that can be locked along a ramp in the retracted position by a spring and a valve is provided to equalize the pressure difference between the inside and outside of the wellbore. The blades can be expanded along the ramp by opening the valve so that the higher pressure inside the wellbore pushes the blades out against the force of the spring.

10

Optionally, the drill bit may have three radial positions. In addition to a full retracted position, and an expanded position for running in and out of the wellbore with ease, a more expanded position with a diameter larger than that of the wellbore may also be provided, so that the drill bit can also act as a conventional reamer or under-reamer to enlarge the wellbore if and when it's needed.

15

The bottomhole assembly may comprise one or more full-gauge stabilizers and optionally an under-gauge stabilizer. Each full-gauge stabilizer of the BHA is retractable and expandable radially. If an under-gauge stabilizer is provided, it can optionally be retractable and expandable radially. In order to radially expand and retract, the stabilizers may comprise hinged parts that can swing in and out, or blades that can slide in and out, or blades on ramps or use any other suitable mechanisms.

20

The under-gauge stabilizer, if provided, may not be able to expand and retract radially. Alternatively, it may be able to expand and retract radially to two or more positions, so that it can e.g. help adjust the BHA tendency which in turn helps control the direction of drilling. Three positions may be provided so that the BHA can drill straight, up or down. Alternatively, further positions may be provided so that drilling direction can be controlled more precisely.

30

If no under-gauge stabilizer is provided, the steering function can be provided by a full-gauge stabilizer which comprises more than two radial positions. In addition to the full-gauge position, and the slightly retracted position for running through the wellbore, one or more positions with even smaller diameters can be provided. Three of its positions may be used for directional control, so that the BHA can be steered to drill straight, up or down. Alternatively, further positions may be provided so that drilling direction can be controlled more precisely.

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Each of the first, second, third and/or additional stabilizers may either be stand-alone, or part of other components such as rotary-steerable systems or LWD tools.

- 5 Other full-gauge components may also be provided which has a diameter which is substantially the same as that of the wellbore. All full-gauge components of the BHA must be retractable radially to a diameter which is substantially smaller than that of the wellbore, so that it is easier for the BHA to run into the wellbore, and be pulled out of the wellbore.
- 10 In operation, all full-gauge or near full-gauge components of the BHA are retractable to substantially less than full-gauge, and re-expandable out to full-gauge on command. The actual mechanism to achieve expansion and retraction may be electro-mechanical or hydraulic. In a hydraulic system, the expandable blades of a component may be locked in a retracted position by a spring and a valve is provided to equalize the pressure difference
- 15 between the inside and outside of the wellbore. The blades can be expanded by opening the valve so that the higher pressure inside the wellbore pushes the blades out against the force of the spring.

Such on demand control may be achievable using simple ball-drop or dart-drop technology.

- 20 In such cases, the valves may be actuated by ball drop or dart drop.

Alternatively, different forms of telemetry may be used. A telemetry is a system for converting the measurements recorded by a wireline or MWD tool into a suitable form for transmission to the surface. In the case of wireline logging, the measurements are converted

25 into electronic pulses or analogue signals that are sent up the cable. In the case of MWD, they are usually converted into an amplitude- or frequency-modulated pattern of mud pulses. Some MWD tools use wirelines run inside the drillpipe. Others use wireless telemetry, in which signals are sent as electromagnetic waves through the Earth. Wireless telemetry is also used downhole to send signals from one part of an MWD tool to another.

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For example, mud pulse telemetry can be used. Mud pulse telemetry is a method of transmitting LWD and MWD data acquired downhole to the surface, using pressure pulses in the mud system. The measurements are usually converted into an amplitude- or frequency-modulated pattern of mud pulses. The same telemetry system is used to transmit

35 commands from the surface.

Alternatively electromagnetic (EM) telemetry or thru-earth telemetry can be used. They are capable of transmitting data much faster than mud pulse telemetry.

5 In some embodiments, a communications technology such as a wired drill-pipe to transmit commands down to the BHA to open and close its expandable components, and also with confirmation signals from the BHA that they have opened or shut.

Such on demand control technologies all allow remote control of the drill bit and any stabilizers of the BHA, so that control can be achieved from the surface while the BHA works downhole.

10

The BHA would normally be run into hole in its retracted and under-gauge position, enabling it to pass over any cuttings beds, and also potentially pass through any restrictions that had developed since the last drilling period. If there were some concerns that the hole had become under-gauge due to creep, or for other reasons such as partial hole collapse, 15 the drill bit might be expanded while the full-gauge stabilizers stay retracted, to allow these restrictions to be milled out but without risking problems with stabilizer pass-through. This helps protect the stabilizers of the system, especially full-gauge stabilizers, from unnecessary damage when pass through the restrictions.

20 To achieve this, it is advantageous to provide separate and independent control of the drill bit and each stabilizer of the BHA, so that each of them can be expanded and retracted independently of the other components of the BHA. It is therefore desirable to provide a separate control mechanism for each expandable and retractable component of the BHA. Furthermore, it may be desirable to provide independent control mechanisms for some or 25 all positions of each expandable and retractable component, so that directional control by a stabilizer or reamer action by the drill bit may be controlled separately and independently of retraction for running through the wellbore.

30 The control mechanism of each component and/or each position of each component may be of the same type such as all using a wired drill pipe, or of different types for example some may use a communication technology while others use ball-drop or dart-drop technology.

35 Once the bottom of the hole had been reached or whenever desirable, all full-gauge components of the BHA, such as the drill bit and stabilizers, may be expanded to their normal drilling diameter, and drilling can start as normal. An under-gauge stabilizer may be controlled indecently for directional control.

Whenever desired, e.g. at the end of drilling an interval, the retractable BHA components can be retracted prior to pulling out of the hole, either with or without circulation.

5 Since the maximum diameter of the retracted BHA is significantly less than the hole diameter, withdrawing the BHA becomes easier. The retracted components of the BHA can simply ride over the top of the cuttings, both when pulling out of the hole and running into the hole. Even if the cuttings bed is too big for the BHA to ride over the top, the build-up of cuttings above the BHA when pulling out would be reduced.

10

If during the course of drilling, some component of the BHA becomes stuck due to the presence of a restriction in the wellbore, retracting the full-gauge components may be enough to release it. In addition, if circulation has been restricted, circulation will become easier after retraction of some or all full-gauge components of the BHA.

15

If the BHA can now be pulled up above the sticking point, then by re-expanding some or all of the components, the BHA can be returned to bottom while removing the restriction and clearing out the borehole. For example, the drill bit may be expanded and locked to its full-gauge position for removing the restriction, while full-gauge stabilizers can stay locked in their retracted positions for protection.

20

If instead of retracting all full-gauge components, they are retracted one-by-one, the position of the stuck point can be identified more precisely, aiding in remedial action. It is understood that the full-gauge components are retracted sequentially, but the order in which this is done is not important. It is possible that not all full-gauge components need to be retracted before the location of the restriction can be identified.

25

If the drill bit is provided with an additional radial position with a diameter which is substantially larger than that of the wellbore, it can act as a ream or an under-reamer to enlarge the diameter of the wellbore. In such systems, it is no longer necessary to provide a separate reamer or under-reamer.

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While the invention has been described in conjunction with the exemplary embodiments described above, many equivalent modifications and variations will be apparent to those skilled in the art when given this disclosure. Accordingly, the exemplary embodiments of the invention set forth above are considered to be illustrative and not limiting. Various

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changes to the described embodiments may be made without departing from the spirit and scope of the invention.

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CLAIMS

1. A bottomhole assembly for drilling a wellbore through an earth formation
5 comprising: a plurality of full-gauge components, wherein the plurality of full-gauge
components are each radially expandable and retractable between their respective first
positions and their respective second positions, wherein their first positions each have a
diameter which is substantially the same as that of the wellbore, wherein their second
positions each have a diameter which is substantially smaller than that of the wellbore, and
10 wherein the plurality of full-gauge components comprise:
a drill bit that is radially expandable and retractable between its first position and
its second position, wherein its first position has a diameter which is substantially the same
as the diameter of the wellbore, and wherein its second position has a diameter that is
substantially smaller than the diameter of the wellbore; and
15 a first stabilizer that is radially expandable and retractable between its first position
and its second position, wherein its first position has a diameter that is substantially the
same as the diameter of the wellbore, and wherein its second position has a diameter that
is substantially smaller than the diameter of the wellbore.
- 20 2. A bottomhole assembly of claim 1, wherein the diameter of the first position of the
drill bit is substantially the same as the diameter of the first position of the first stabilizer.
3. A bottomhole assembly according to claim 1 or claim 2, wherein the diameter of the
25 second position of the drill bit is substantially the same as the diameter of the second
position of the first stabilizer.
4. A bottomhole assembly of any of the preceding claims, further comprising a second
stabilizer that is not radially expandable and retractable, wherein the second stabilizer has
a diameter which is substantially smaller than that of the wellbore.
- 30 5. A bottomhole assembly of any of claims 1-3, further comprising a second stabilizer
that is radially expandable and retractable between its first position and its second position,
wherein each of its first and second positions has a respective diameter which is
substantially smaller than that of the wellbore.
- 35 6. A bottomhole assembly of any of claims 1-3, further comprising a second stabilizer
that is radially expandable and retractable between its first position and its second position,

wherein its first position has a diameter which is substantially the same as that of the wellbore, and wherein its second position has a diameter which is substantially smaller than that of the wellbore.

- 5 7. A bottomhole assembly of any preceding claim, further comprising a third stabilizer that is radially expandable and retractable between its first position and its second position, wherein its first position has a diameter which is substantially the same as that of the wellbore, and wherein its second position has a diameter which is substantially smaller than that of the wellbore.
- 10 8. A bottomhole assembly of any preceding claim, wherein the first stabilizer comprises three or more radial positions.
- 15 9. A bottomhole assembly of any preceding claim, wherein the second stabilizer comprises three or more radial positions.
- 20 10. A bottomhole assembly of any preceding claim, wherein the drill bit comprises three or more radial positions.
- 25 11. A bottomhole assembly of any preceding claim, wherein the drill bit comprises a fixed cutter bit and a near bit reamer.
- 30 12. A bottomhole assembly of any preceding claim, wherein the expansion and retraction of the drill bit and each of the stabilizers are controllable remotely.
- 35 13. A bottomhole assembly of any preceding claim, wherein the expansion and retraction of the drill bit and each of the stabilizers are controllable independently.
14. A bottomhole assembly of claim 12 or 13, wherein the expansion and retraction of the drill bit and each of the stabilizers are actuatable using pressure changes.
15. A bottomhole assembly of any of claims 12-14, wherein the expansion and retraction of the drill bit and each of the stabilizers are controllable using a wired drill pipe.
16. A bottomhole assembly of any of claims 12-14, wherein the expansion and retraction of the drill bit and each of the stabilizers are controllable using ball drop or dart drop.

17. A bottomhole assembly of any of claim 12-14, wherein the expansion and retraction of the drill bit and each of the stabilizers are controllable using electromagnetic telemetry.
- 5 18. A bottomhole assembly of any of claims 12-14, wherein the expansion and retraction of the drill bit and each of the stabilizers are controllable using thru-earth telemetry.
- 10 19. A bottomhole assembly of any preceding claim, further comprising a rotary steerable system
20. A bottomhole assembly of any preceding claim, further comprising a motor.
- 15 21. A method of drilling a wellbore through an earth formation using a bottomhole assembly of any of the claim 1 to 20, the method comprising:
retracting each full-gauge component of the bottomhole assembly, whose respective first position has a diameter which is substantially the same as that of the wellbore, to its respective second position;
running the bottomhole assembly from the up-hole side to the down-hole side of the
20 well;
expanding each full-gauge component to its respective first position; and
drilling the wellbore.
- 25 22. A method of performing a wellbore operation using a bottomhole assembly of any of the claim 1 to 20, the method comprising:
retracting each full-gauge component of the bottomhole assembly, whose respective first position has a diameter which is substantially the same as that of the wellbore, to their respective second position; and
running the bottomhole assembly from the down-hole side to the up-hole side of the
30 well.
- 35 23. A method for removing a restriction in a wellbore using a bottomhole assembly of any of the claim 1 to 20, the method comprising:
expanding the drill bit to its first position;
retracting each full-gauge stabilizer of the bottomhole assembly, whose respective first position has a diameter which is substantially the same as that of the wellbore, to its respective second position;

running the bottomhole assembly from the up-hole side to the down-hole side of the well; and
removing the restriction.

- 5 24. A method for locating a restriction in a wellbore using a bottomhole assembly of any of the claim 1 to 20, the method comprising:
retracting the drill bit to its second position;
retracting each full-gauge stabilizer of the bottomhole assembly, whose respective first position has a diameter which is substantially the same as that of the wellbore, to its
10 respective second position; and
identifying the location of the restriction.
25. An apparatus substantially as described in the description and/or drawings.
- 15 26. A method substantially as described in the description and/or drawings.

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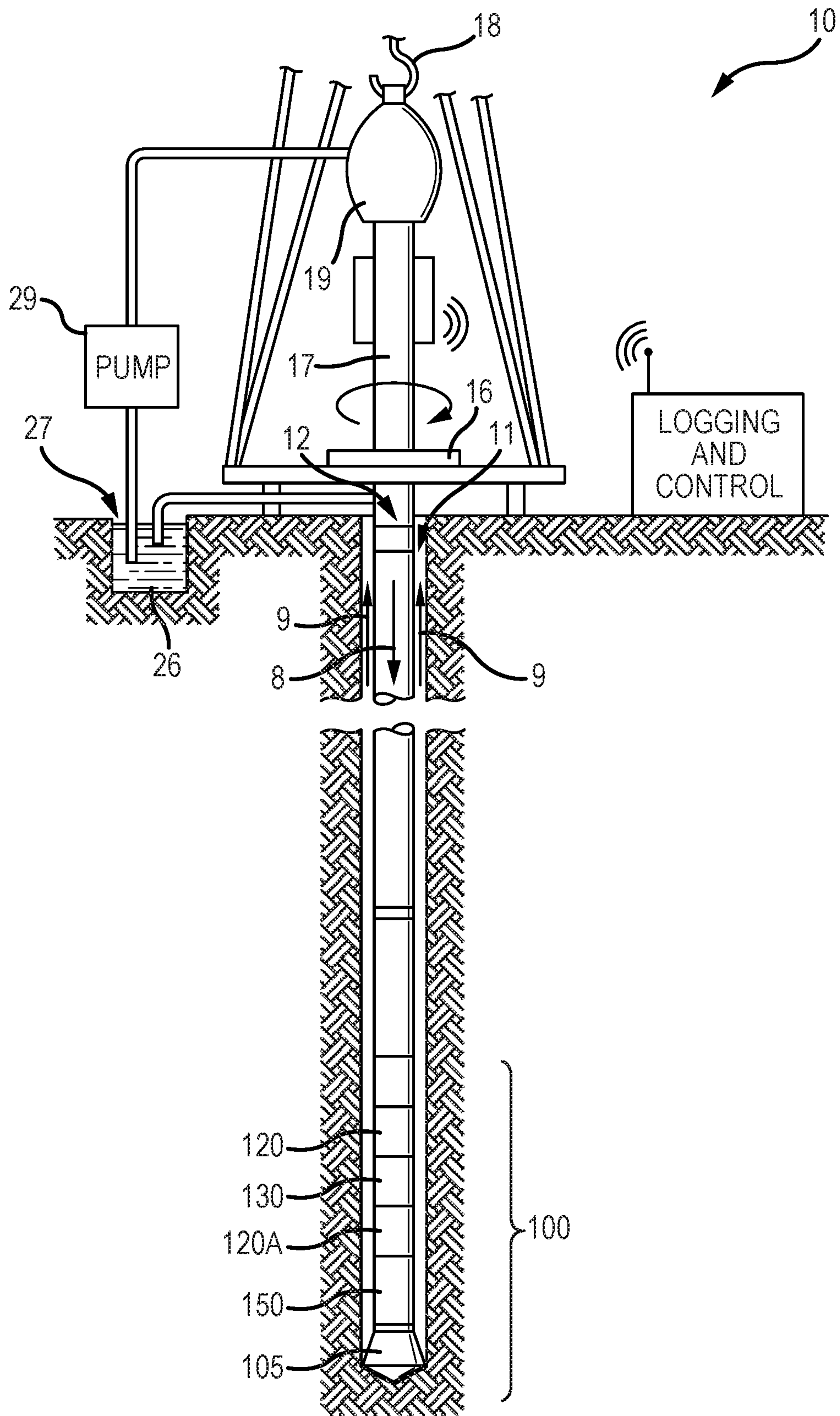


FIG.1

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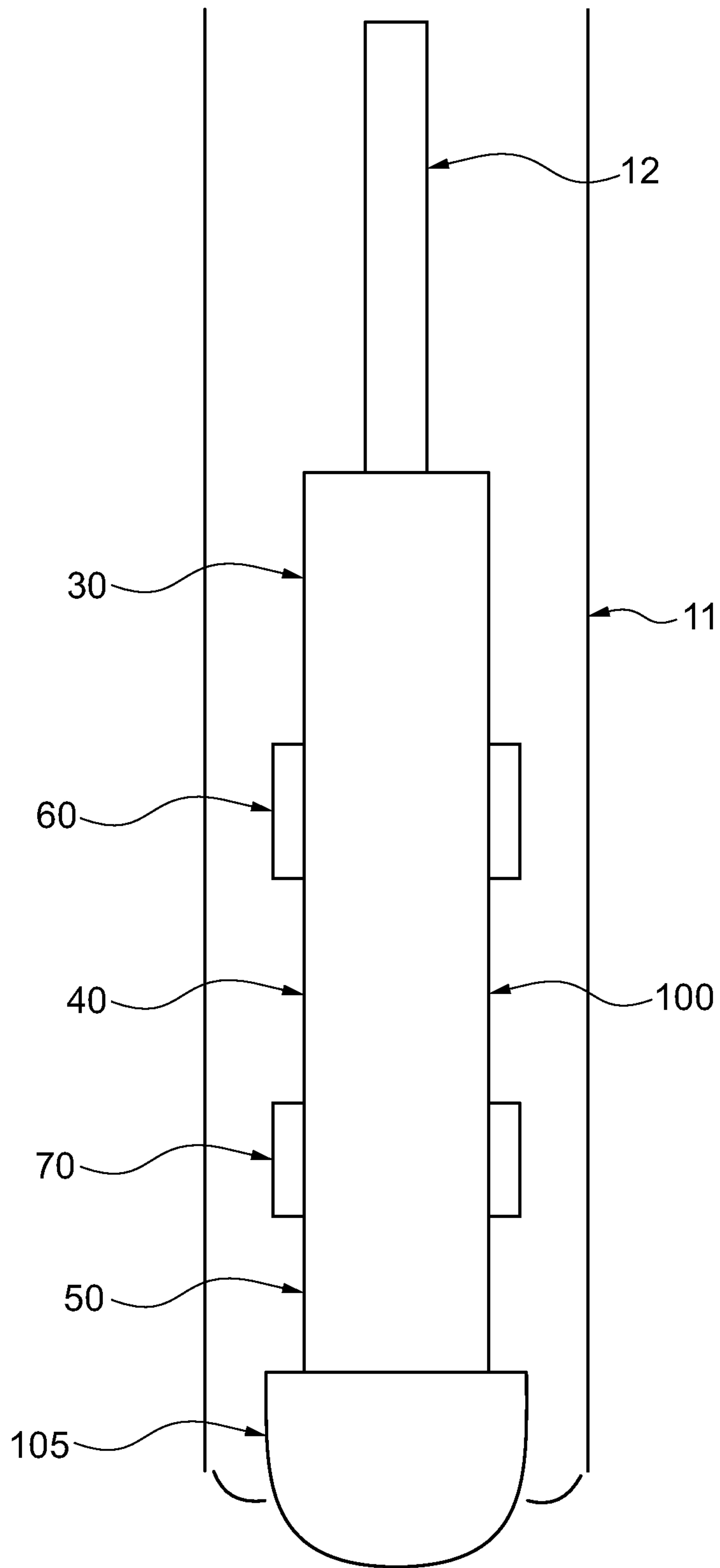


Fig. 2

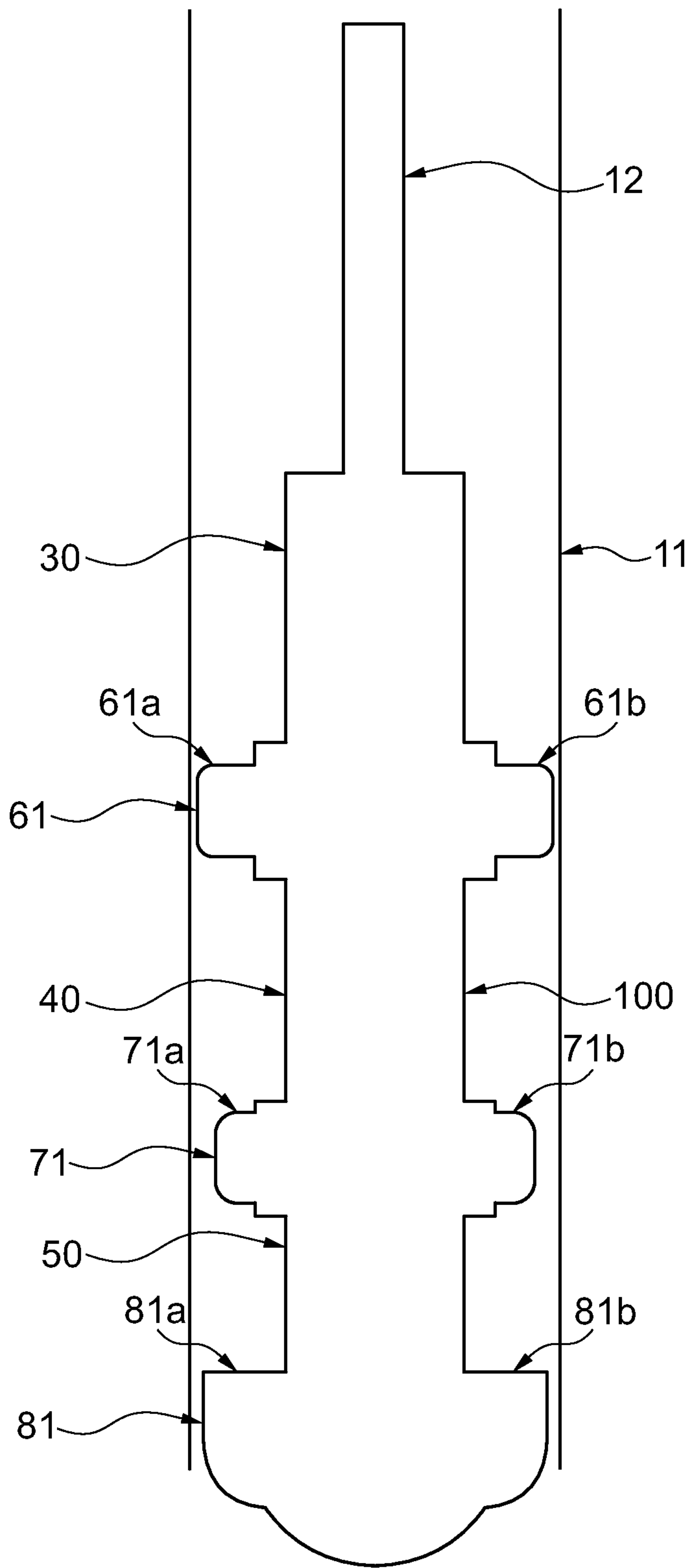


Fig. 3

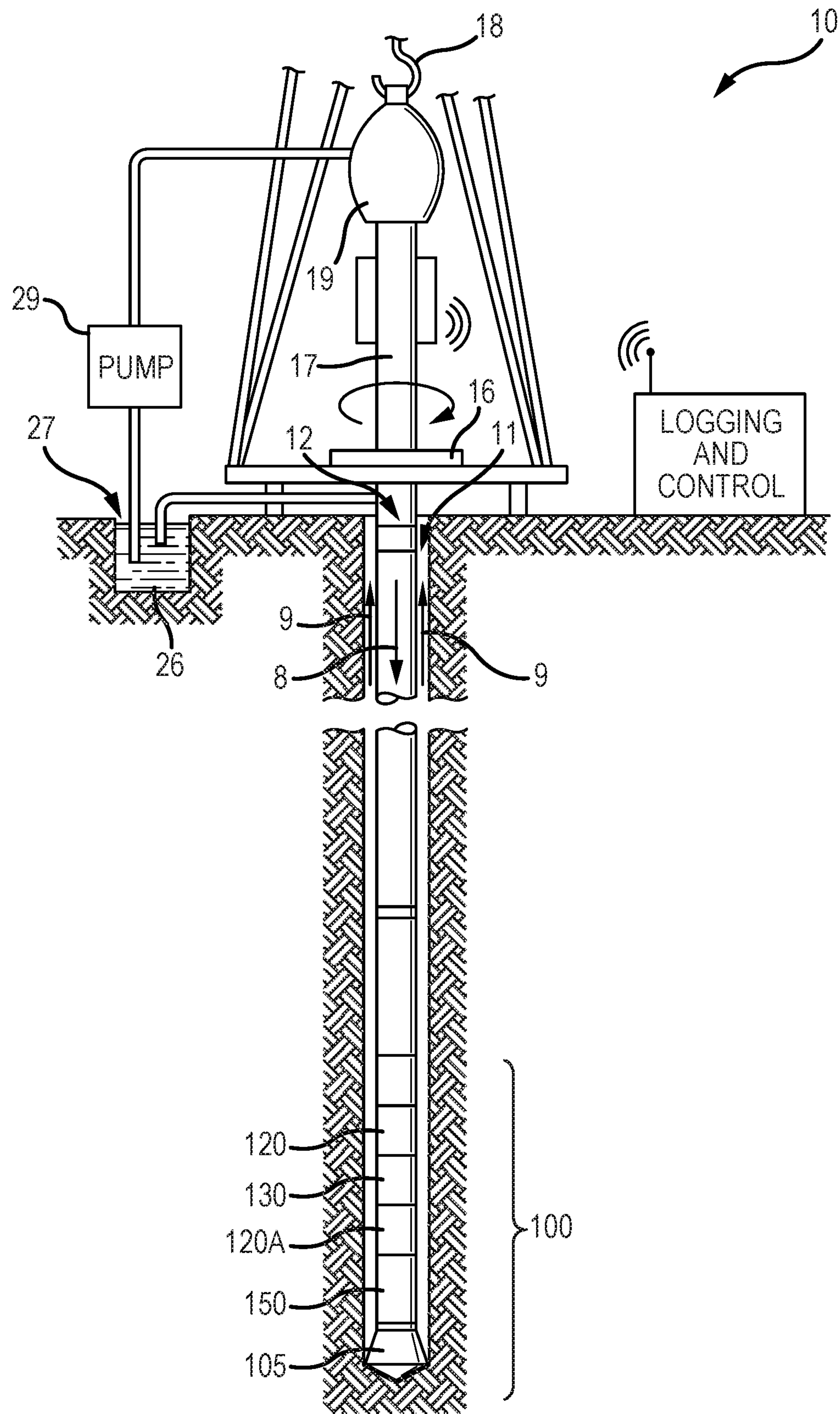


FIG.1