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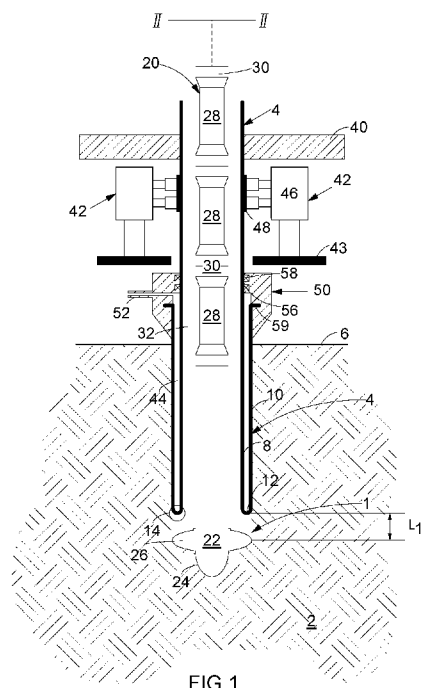


FIG.1

(57) Abstract: The invention discloses a system (fig.1) and a method for lining a wellbore. The system comprises a drill string (20) for drilling the wellbore; an expandable tubular element (84) enclosing the drill string (20), wherein a lower end portion of a wall of the expandable tubular element (14) is bent radially outward and in axially reverse direction to define an expanded tubular section (10) extending around an unexpanded tubular section (8); a pushing device (42) for pushing the unexpanded tubular section (8) into the expanded tubular section (10); and a releasable drilling annulus sealing device (70) for closing an annular opening between an upper end of the expandable tubular element and the drill string.

SYSTEM AND METHOD FOR RADially EXPANDING A TUBULAR  
ELEMENT

The present invention relates to a system and a method for radially expanding a tubular element.

The technology of radially expandable tubular elements finds increasing application in the industry of oil and gas production. Wellbores are generally provided with one or more casings or liners to provide stability to the wellbore wall and/or to provide zonal isolation between different earth formation layers. The terms "casing" and "liner" refer to tubular elements for supporting and stabilising the wellbore wall. Typically, a casing extends from surface into the wellbore and a liner extends from a certain depth further into the wellbore. However, in the present context, the terms "casing" and "liner" are used interchangeably and without such intended distinction.

In conventional wellbore construction, several casings are set at different depth intervals, and in a nested arrangement. Herein, each subsequent casing is lowered through the previous casing and therefore has a smaller diameter than the previous casing. As a result, the cross-sectional area of the wellbore that is available for oil and gas production decreases with depth.

To alleviate this drawback, it is possible to radially expand one or more tubular elements at a desired depth in the wellbore, for example to form an expanded casing, expanded liner, or a clad against an existing casing or liner. Also, it has been proposed to radially expand each subsequent casing to substantially the same diameter as the previous casing to form a monodiameter

wellbore. It is thus achieved that the available diameter of the wellbore remains substantially constant along (a section of) its depth as opposed to the conventional nested arrangement.

5 EP-0044706-A2 discloses a method of radially expanding a flexible tube of woven material or cloth by eversion thereof in a wellbore, to separate drilling fluid pumped into the wellbore from slurry cuttings flowing towards the surface. The woven material or cloth  
10 however has inadequate collapse resistance to stabilize or support the wellbore wall and is unsuitable to substitute regular casing.

WO-2009/074632 discloses a wellbore system for radially expanding a tubular element in a wellbore. The  
15 wall of the tubular element is induced to bend radially outward and in axially reverse direction so as to form an expanded section extending around an unexpanded section of the tubular element. The length of the expanded tubular section is increased by pushing the unexpanded  
20 section into the expanded section. The expanded section retains the expanded shape. A number of seals seal the space between the drill string, the unexpanded tubular section and a conduit for drilling fluid. The unexpanded tubular section is continuously extended at its upper end  
25 by bending a metal sheet around the drill string. This eliminates the need to disconnect the seals.

The present invention aims to improve the above referenced prior art method and system.

The present invention therefore provides a system for  
30 lining a wellbore, the system comprising:

- a drill string for drilling the wellbore;
- an expandable tubular element enclosing the drill string, wherein a lower end portion of the wall of the

expandable tubular element is bent radially outward and in axially reverse direction to define an expanded tubular section extending around an unexpanded tubular section;

5           - a pushing device for axially extending the expanded tubular section by forcing the unexpanded section to move relative to the expanded tubular section;

          - a releasable drilling annulus sealing device for closing an annular opening between an upper end of the  
10       expandable tubular element and the drill string.

          By moving the unexpanded tubular section downward relative to the expanded tubular section, the tubular element is effectively turned inside out. The tubular element is progressively expanded without an expander  
15       that is pushed, pulled or pumped through the tubular element. The expanded tubular section can form a casing or liner in the wellbore. The expanded tubular liner has a collapse resistance which is adequate to stabilize or support the wellbore wall.

20           The drilling annulus sealing device can seal the drilling annulus, i.e. the annular opening at the upper end of the unexpanded tubular section. This allows (drilling) fluid within the system to be pressurised. The sealing device enables the drill string and/or sections  
25       of the expandable tubular liner to be connected or disconnected, while ensuring that well control operations can be carried out in case of a kick, i.e. an unexpected influx from the formation. Formation herein indicates the material around the wellbore, which may include for  
30       instance rock, salt or shale. Preferably, the sealing capability of the sealing device can withstand pressures that may be experienced during well control operations.

Preferably, the drilling annulus sealing device is designed to withstand pressures that may be expected in case of a kick or blowout. Depending on the specifics of the wellbore and of the formation, the sealing device can  
5 for instance contain pressures up to 200 bar or up to 1600 bar or more, for instance about 400 bar to 800 bar.

It is preferred that the wall of the expandable tubular element includes a material that is plastically deformed during expansion. The expanded tubular section  
10 will retain an expanded shape due to the plastic deformation, i.e. permanent deformation, of the wall of the expandable tubular element. There is no need to apply an external force or pressure to maintain the expanded tubular section in its expanded form. If, for example,  
15 the expanded tubular section engages the wellbore wall, no additional radial force or pressure needs to be exerted to keep the expanded tubular section against the wellbore wall.

The wall of the tubular element may comprise a metal  
20 such as steel or any other ductile metal capable of being plastically deformed by eversion of the tubular element. The expanded tubular section has adequate collapse resistance to support or stabilize the wellbore wall. Depending on the respective formation, the collapse  
25 resistance of the expanded tubular section may exceed, for example, 100 bar or more, for instance more than 150 bar or more than 1500 bar.

Suitably the bending zone is induced to move in axial direction relative to the remaining tubular section by  
30 inducing the remaining tubular section to move in axial direction relative to the expanded tubular section. For example, the expanded tubular section is axially fixed at some location, while the unexpanded tubular section is

moved in axial direction through the expanded tubular section to induce said bending of the wall.

In order to induce said movement of the remaining tubular section, the remaining tubular section is subjected to an axially compressive force acting to induce said movement. The axially compressive force preferably at least partly results from the weight of the remaining tubular section. The pushing device can supplement the weight of the unexpanded tubular section by applying an additional external force to the remaining tubular section to induce said movement. The additional force applied by the pushing device may be upward or downward. For instance, as the length and hence the weight of the unexpanded tubular section increases, an upward force may need to be applied to the unexpanded tubular section to maintain the total force applied to the unexpanded section within a predetermined range. Maintaining the total force within said range will prevent uncontrolled bending or buckling of the bending zone.

If the bending zone is located at a lower end of the tubular element, whereby the remaining tubular section is axially shortened at a lower end thereof due to said movement of the bending zone, it is preferred that the remaining tubular section is axially extended at an upper end thereof in correspondence with said axial shortening at the lower end thereof. The remaining tubular section gradually shortens at its lower end due to continued reverse bending of the wall. Therefore, by extending the remaining tubular section at its upper end to compensate for shortening at its lower end, the process of reverse bending the wall can be continued until a desired length of the expanded tubular section is reached. The remaining

tubular section can be extended at its upper end, for example, by connecting a tubular portion to the upper end in any suitable manner such as by welding. Alternatively, the remaining tubular section can be provided as a coiled tubing which is unreeled from a reel and subsequently inserted into the wellbore.

Optionally the bending zone can be heated to promote bending of the tubular wall.

The invention will be described hereinafter in more detail and by way of example with reference to the accompanying drawings in which:

Fig. 1 shows a vertical cross section of a lower portion of an embodiment of a system according to the present invention;

Figs. 2-9 show a vertical cross section of respective embodiments of an upper portion of the system of Figure 1;

Fig. 10 shows a vertical cross section of an embodiment of a backing gas tool;

Figs. 11-12 show a vertical cross section of an embodiment of the system of the invention comprising an emergency shut-off sleeve;

Figs. 13-29 schematically show respective steps of an embodiment of a method according to the present invention;

Figs. 30 and 31 show the backing gas tool of Figure 10 in a state of use;

Fig. 32 shows an embodiment of the system of the invention comprising a blow-out preventer; and

Fig. 33 shows an embodiment of the system of the invention comprising another blow-out preventer.

In the drawings and the description, like reference numerals relate to like components.

Figure 1 shows a wellbore 1 formed in an earth formation 2. A radially expandable tubular element 4, for instance an expandable steel liner, extends from surface 6 down into the wellbore 1. The tubular element 4 comprises an unexpanded tubular section 8 and a radially expanded tubular section 10. The unexpanded section 8 extends within the expanded section 10. Preferably, an outer diameter of the expanded tubular section 10 is substantially equal to the diameter of the wellbore 1.

Although the wellbore shown in Figure 1 extends vertically into the formation 2, the present invention is equally suitable for any other wellbore. For instance, the wellbore 1 may extend at least partially in horizontal direction. Herein below, upper end of the wellbore refers to the end at surface 6, and lower end refers to the end down hole.

At its lower end, the wall of the unexpanded section 8 bends radially outward and in axially reverse (in Fig. 1 the upward) direction so as to form a curved lower section 12, defining a bending zone 14 of the tubular element 4. The curved section 12 is U-shaped in cross-section and interconnects the unexpanded section 8 and the expanded section 10.

A drill string 20 may extend from surface through the unexpanded liner section 8 to the lower end of the wellbore 1. The lower end of the drill string 20 is provided with a drill bit 22. The drill bit comprises, for instance, a pilot bit 24 having an outer diameter which is slightly smaller than the internal diameter of the unexpanded liner section 8, and a reamer section 26 having an outer diameter adapted to drill the wellbore 1 to its nominal diameter. The reamer section 26 may be radially retractable to a smaller outer diameter,



allowing it to pass through the unexpanded liner section 8, so that the drill bit 22 can be retrieved through the unexpanded liner section 8 to surface. The drill string 20 may comprise multiple drill pipe sections 28. The pipe sections 28 may be mutually connected at respective ends by male and female threaded connections 30. An annular space 32 between the drill string 20 and the unexpanded tubular section 8 is referred to as the drilling annulus 32.

The connections 30 are not shown in detail, but comprise for instance threaded, pin and box type connections. The connections 30 may comprise joints fabricated with male threads on each end, wherein short-length coupling members (not shown) with female threads are used to join the individual joints of drill string together, or joints with male threads on one end and female threads on the other. Said threaded connections may comprise connections which are standardized by the American Petroleum Institute (API). As indicated by the line II-II, the drill string 20 can be connected to any of the devices shown in Figures 2 to 4.

Figure 1 also shows a rig floor 40, which is elevated with respect to the surface 6 and encloses an upper end of the drill string 20 and of the unexpanded tubular section 8. The rig floor 40 is typically part of a drilling rig, and can be arranged on supports 41 (As shown in Fig. 13). A pipe pusher 42, which is for instance arranged below the rig floor, encloses the unexpanded section 8. The pipe pusher is for instance supported by base frame 43, which may be elevated with respect to the surface by means of base frame supports 45 (see Fig. 13). The base frame 43 provides stability, and may for instance be connected to the drilling rig or be

supported at surface 6 (see for instance Fig. 13). The pipe pusher may comprise one or more motors 46, which are arranged on the base frame, and one or more conveyer belts 48 which can be driven by the respective motors.

5 Each conveyer belt 48 engages the outside of the unexpanded section 8. The conveyer belts 48 can exert force to said unexpanded section 8 to force the unexpanded section to move into the expanded section 10. Other embodiments of the pipe pusher 42 are conceivable,  
10 which will be able to exert downward or upward force to the unexpanded section.

A blind annulus sealing device 50, or BABOP, is connected to the upper end of the expanded liner section 10 to seal a blind annulus 44, i.e. the annular space  
15 between the unexpanded liner section 8 and the expanded liner section 10. The sealing device comprises a conduit 52 which is connected to a pump (not shown) for pumping fluid into or out of the blind annulus 44. The annular space 44 is referred to as blind annulus as it is closed  
20 at the downhole end by the bending zone 14. The sealing device includes one, two or more annular seals 56, 58. The seals 56, 58 engage the outside of the unexpanded section 8 and prevent said fluid to exit the blind annulus. Said seals 56, 58 allow the unexpanded liner  
25 section 8 to slide in axial direction relative to the sealing device 50. Preferably, the sealing device 50 comprises at least two seals 56, 58 to improve safety and reliability in case one of the seals may fail.

The blind annulus sealing device 50 can be regarded  
30 as a wellhead or a blind annulus blow out preventer. Therefore, the seals 56, 58, the connection of the device 50 to the upper end of expanded section 10, and one or more valves (not shown) for closing conduit 52 are

preferably able to at least withstand fluid pressures that may arise in a well control situation. Depending on specifics of the formation, the blind annulus sealing device 50 is for instance able to contain pressures that may be expected in case of a blowout, for instance in the range of 200 bar to 1600 bar or more, for instance about 400 bar to 800 bar or more.

The expanded liner section 10 is axially fixed, by any suitable fixation means, to prevent axial movement. The expanded liner section 10 may be fixated at its upper end at surface. For instance, said upper end of the expanded section may be connected to a ring or flange 59, for instance by welding and/or screwing. Said ring 59 can be attached to or incorporated in any suitable structure at surface, such as the blind annulus sealing device 50. The inner diameter of said ring may be larger than the outer diameter of the expanded tubular section 10. Optionally, the expanded section 10 may be fixed to the wellbore wall 12, for instance by virtue of frictional forces between the expanded liner section 10 and the wellbore wall 12 as a result of the expansion process. Alternatively, or in addition, the expanded liner section 10 can be anchored, for instance to the wellbore wall, by any suitable anchoring means.

Figure 2 shows a top drive 60 connected to an upper end connection part 62, which is rotatable with respect to the top drive. Preferably, the upper end connection part comprises a flush pipe, having a smooth outer surface. The pipe end 64, which is remote from the top drive, is provided with a threaded connection 30 as described above. The threaded end 64 is connected to an additional drill string section 66. Typically, the additional drill string section 66 will be substantially

equal to the drill string sections 28, shown in Fig. 1. At the interface indicated by line I-I, the additional drill pipe section 66 can be connected to the upper end of the drill string 20 (shown in Fig. 1).

5           A drilling annulus sealing device 70 covers the top end of the drilling annulus 32. The drilling annulus sealing device 70 comprises a housing 72, which encloses the connection part 62 and provides an internal space 74. At the top end, near the top drive 60, the housing  
10           comprises one, two or more seals 76, 78, which engage the outside of the pipe 62. Preferably, the seals 76, 78 enable the housing to slide along the pipe 62. At the opposite end, the housing may comprise one, two or more seals 80, 82 which engage the outside of an additional  
15           expandable pipe section 84. In addition to the seals, the housing may comprise grippers 86. An activation line 88 is connected to the housing for activating or releasing the seals 80, 82 and/or the grippers 86. A fluid conduit 90 is connected to the internal space 74 for supply or  
20           drainage of (drilling) fluid to or from the annular space 32.

          The drilling annulus sealing device 70 may also be referred to as drilling annulus blow out preventer (DABOP) 70. The seals 76-82, the grippers 86, and one or  
25           more valves (not shown) for closing conduits 88 and 90 are preferably able to at least withstand fluid pressures that may arise in a well control situation. Depending on specifics of the formation and the expected maximum pore pressures, the DABOP 70 is for instance designed to  
30           withstand pressures in the range of about 200 bar to 1600 bar or more, for instance about 400 to 800 bar.

          The drilling annulus sealing device 70 may comprise any number of seals, for instance one seal 76 and one

seal 80, or a plurality of seals. In a practical embodiment, two seals 76, 78 to seal with respect to the pipe 62 and two seals to seal with respect to the tubular section 84 will provide a balance between for instance fail-safety and reliability on one hand and costs on the other hand.

Optionally, the system of the invention may comprise a backing gas tool 92 (Fig. 2). The backing gas tool is a cylindrical sleeve, which can slide along the drill string 20 and the upper end connection 62. A detailed description of the tool 92 is provided below with respect to Figure 10.

In another embodiment, shown in Fig. 3, the drilling annulus sealing device 70 comprises an extending part or stinger 100. The stinger is adapted to extend into the inside of the additional expandable pipe section 84. The stinger may comprise seals 102, 104 and/or grippers 106 to engage the upper end of the pipe section 84. The stinger may comprise seals 108 to engage a lower end of the pipe section 84, and seals 110 to engage the inside of the upper end of the unexpanded tubular section 8 (shown in Fig. 1). A backing gas tool 192 may be integrated in the stinger between the seals 108, 110. The length of the stinger 100 may be designed such that the backing gas tool 192 overlaps the interface between the additional expandable pipe section 84 and the unexpanded tubular section 8.

The stinger may be at least slightly longer than the pipe section 84 so that the stinger may extend into the unexpanded section 8, which will enable the stinger to function as an alignment tool for aligning the pipe section 84 and the unexpanded section 8. In practice, the length of the pipe section 84 may be in the range of

about 5 to 30 metres, for instance about 10 metres. The stinger will for instance be about 2% to 10% longer, for instance 5% longer than the pipe section 84. An annular space 112 is provided between the stinger and the pipe 62 to provide a fluid connection from the annulus 32 to the space 74 and the conduit 90.

The drilling annulus sealing device 70 shown in Figure 4 comprises the seals 80, 82 to engage the outside of the expandable pipe section 84, as well as the stinger 100 provided with the seals 102, 104, the grippers 106, the seals 108, 110 and the backing gas tool 192. The seals 80, 82 are included in the housing 72, which encloses the pipe 62 and at least part of the expandable pipe 84. The double barrier provided by the inner seals 102, 104, engaging the inside of the expandable pipe 84, and the outer seals 80, 82, engaging the outside of the expandable pipe 84, improves the reliability and leak-tightness of the blow out preventer 70.

Figures 5 and 6 show a drilling annulus sealing device 70 having a stinger 100 which is extendable, i.e. has an adjustable length. In an exemplary embodiment, the stinger 100 comprises a telescopic assembly of cylindrical parts 120, 122, 124. Herein, a first part 120 is fixedly connected to the upper section of the housing. Said upper section includes for instance the seals 102, 104 and the grippers 106. Second part 122 and third part 124 are telescopically movable with respect to the first part, between a collapsed position (shown in Figure 5) and an extended position (shown in Figure 6). The third part 124 is fixedly connected to a stinger section comprising the backing gas tool 192 and the seals 108, 110. The extendable stinger may include any number of telescopic parts, i.e. two or three telescopic parts or

more. The extendable stinger may be included in for instance the embodiments of the drilling annulus sealing device 70 shown in Figures 3 and 4.

5 The extendable stinger 100, shown in Figures 5 and 6, improves the flexibility and adaptability of the drilling system of the invention. For instance, a drilling rig (not shown) will typically have a fixed height, and will therefore be suitable for drill pipe sections 66 and expandable pipe sections 84 of a predetermined length, or  
10 up to a maximum length. The extendable stinger of the invention enables for instance the use of longer, or multiple and interconnected, expandable pipe sections 84 in combination with the same rig, and thus effectively increase said maximum length.

15 Vertical movement of the drilling annulus sealing device 70 with respect to the top drive 60 may be arranged in various ways, wherein Figures 7 to 9 show examples of embodiments. For instance, as shown in Figure 7, the drilling annulus sealing device 70 can be arranged  
20 to move together with the top drive 60. The drilling annulus sealing device 70 may include fixation grippers 130, to fixate the vertical position of the sealing device 70 with respect to the pipe 62 while enabling the pipe 62 to rotate with respect to the sealing device 70.  
25 In another embodiment, a fixation frame 132 fixedly connects the drilling annulus sealing device 70 to the top drive. The frame 132 and/or the grippers 130 will need to be designed to withstand and transfer a force at least equal to or preferably more than a maximum vertical  
30 force which will act on the unexpanded tubular section. Said maximum force is for instance in the order of one or more metric ton ( $\geq 10,000$  N).

In the embodiment of Fig. 8, a flexible connection 134 connects the drilling annulus sealing device 70 to the top drive 60. The flexible connection comprises for instance one or more of a cable, a chain, or a flexible rod. The connection has a maximum length, but is flexible and can be shortened or compressed. Gravity will pull down the drilling annulus sealing device 70 during downward movement of the top drive 60. During upward movement of the top drive, the connection 134 will be at its maximum length and pull up the sealing device 70 in conjunction with the top drive 60. This connection allows vertical movement of the sealing device 70 with respect to the top drive 60 over the distance L3. L3 may be in the range of about 0.5 to 5 metres, for instance about 2 metres.

The drilling annulus sealing device 70 may be connected to the top drive 60 using one or more hydraulic cylinders 136, shown in Figure 9. Each hydraulic cylinder comprises a cylindrical housing 138, which is connected to the top drive 60 at a position 140, and a piston 142 which is movable within the respective cylindrical housing. The lower end of the cylindrical housing is preferably at substantially the same level 144 as a lower end of the top drive, to enable the full stroke of the piston to be used. A part of the cylindrical housings, having length L2, may extend above the top drive 60. Control lines (not shown), including for instance hydraulic lines and electrical lines, will be connected to the hydraulic cylinders.

The hydraulic cylinders 136 enable to adjust the vertical distance L3 between the top drive 60 and the sealing device 70. In addition, at any set distance L3, the hydraulic cylinders will prevent unwanted upward



movement of the sealing device 70 with respect to the top drive 60. The distance L3 may for instance be adjusted between 0 and about 25 metres. The system may be designed such that an upper limit of L3 will be in the order of or larger than the length of the additional expandable pipe 84. The maximum downward force which the cylinders 136 can provide, and which will prevent said unwanted upward movement of the sealing device, can be predetermined depending on expected formation pressures and resulting forces, as described above.

The backing gas tool 92, shown in Figure 10, comprises a cylindrical sleeve 150. The sleeve 150 is sized to fit around and to be able to move along the drill string 20, and to fit within the unexpanded tubular section 8. At its lower end, the sleeve 150 is provided with an inner flexible seal 152 and a first outer flexible seal 154. At its upper end, the sleeve 150 is provided with a second outer flexible seal 156. A pressure chamber 158 is arranged inside the sleeve 150. At one end, the pressure chamber is capped by a flexible balloon 160. One or more valves 162 connect the pressure chamber to the outside of the sleeve between the first and second outer seals 154, 156. The balloon 160 has a predetermined elastic modulus, to enable the balloon to pressurize a certain volume of gas or fluid which is introduced in the pressure chamber to a predetermined pressure. As the tool 92 is designed to enclose the drill string, the tool and the seals and the balloon are ring-shaped in plan view (not shown). Said gas or fluid may be introduced in the pressure chamber 150 via the valves 162, or via a separate injection port (not shown).

Figures 11 and 12 show an embodiment of the system of the invention comprising an emergency shut-off device

170. The device 170 comprises a cylindrical sleeve 172 which encloses the upper end of the unexpanded section 8 and is movable along the length thereof, indicated by arrow 174. The sleeve is for instance located above the rig floor 40, or in a suitable hole or cavity just below the drilling table. The inner surface of the sleeve 172 is provided with first seals 176 and/or first grippers 178, and with second seals 182 and/or second grippers 184. The first and second seals and/or grippers may be activated by any suitable means. Alternatively, the grippers may be connected to an control line (not shown) for activating said grippers. Said control line may include a hydraulic control line.

The emergency shut-off device 170 provides an additional safety barrier to shut-off the annular space 32 and to contain any fluids within the annulus 32 when necessary. The emergency shut-off device 170 can for instance be applied in case a kick is experienced at a time when the additional expandable pipe 84 is not yet connected to the unexpanded section 8, leaving an opening 184 therebetween as shown in Figure 11 which can be closed using the shut-off device 170.

In case of a kick, the rising pressure could expel (drilling) fluid out of the annulus 32 through the opening 184. This may start with relatively small amounts of fluid, in an increasing fashion. To contain the wellbore, ideally the wellbore will be closed by connecting the additional pipe 84 to the unexpanded section 8, for instance by welding. Said welded connection, in conjunction with the sealing device 70 and the respective seals and valves, will ensure that the fluid is contained within the wellbore.

However, if there is not enough time available to connect the additional pipe 84 to the unexpanded tubular section 8, the emergency shut-off device 170 provides a faster solution to close the opening 184. By sliding the device 170 over the opening, wherein the first seals are located on one side of the opening 184 and the second seals are located on the opposite side of the opening, the device 170 will shut-off the opening. In practice, the first and second seals, and the first and second grippers, will be designed to contain pressures expected in a well control situation, similar to the seals and grippers of the sealing device 70. The seals will preferably be designed to withstand pressures in the range of 200 bar to 1600 bar or more, for instance about 400 bar to 800 bar or more.

Herein below, the operation of the system of the present invention is described. The system of the invention, which is shown as an example, comprises a sealing device 70 which includes features of the embodiments thereof as shown in Figures 4 and 9. The method of the invention is applicable using other embodiments in a similar manner. To improve the clarity of the drawings, some features of the system, such as the sealing device 50 and the pipe pusher 42, may be absent in one or more of the figures. The function and operation of said features is expected to be clear from the present description.

Before commencing and repeating the cycle described below, the unexpanded tubular liner will be prepared to form an onset of the expanded tubular section 10. For instance (not shown), initially a lower end portion of the unexpanded tubular element is everted to create a predetermined initial length of expanded tubular section

10. Herein, said lower portion is bent radially outward and in axially reverse direction, to initiate the U-shaped lower section 12 and the expanded liner section 10. The initial short length of expanded liner section 10 that has been formed is axially fixed by any suitable fixation means as described above. The end of said expanded liner section is for instance attached to the ring 59 shown in Fig. 1.

A force is then applied to the unexpanded liner section 8 to push the unexpanded liner section 8 gradually into the expanded liner section 10. As a result, the unexpanded liner section 8 is progressively everted, thereby progressively transforming the unexpanded liner section 8 into the expanded liner section 10. The bending zone 14 proceeds at approximately half the speed of the unexpanded liner section 8.

After these preliminary steps, a cycle of steps commences, as shown in Figures 13 to 29.

Figure 13 shows an exemplary rig 250, comprising a derrick 252. The top drive 60 can be moved along a transport mechanism 254, which is for instance provided with vertical rails 256. The transport mechanism 254 may allow the top drive 60 to move in vertical direction, but additionally may allow rotation and/or displacement in horizontal direction. An additional drill pipe section 66 and an additional expandable pipe section 84 are provided, for instance on the rig floor 40.

The rig 250 may be provided with one or more pipe handling devices 260. A pipe handling device comprises for instance a vertical column 262 and a displaceable arm 264 having a grabbing element 266 for grabbing an additional pipe section. The arm 264 and the grabbing element 266 can move in vertical direction along the

column 262 and can rotate around the column. Additional degrees of freedom and directions of movement are also conceivable. The pipe handling device 260 is for instance driven hydraulically.

5           Alternatively, the rig may be provided with a pipe section stand 270. The pipe stand 270 may be upright or tilted. The pipe stand 270 is for instance tilted with respect to the rig at an angle  $\alpha$  in the range of about 10 to 30 degrees (Fig. 14).

10           The expandable pipe section 84 and the drill pipe section 66 may be provided in any convenient manner. Both may for instance be provided in a tilted pipe stand, or in combination with a pipe handling device 260. Possible movements of the top drive 60 will be adapted to the  
15           choice made. Alternatively, the expandable pipe section 84 and/or the drill pipe section 66 may be provided in a straight pipe stand, wherein the transport mechanism 254 will allow horizontal movement of the top drive 60 to be able to pick up the respective pipe section. Any  
20           combination of the foregoing is also possible.

          The top drive 60 and the connection part 62, including the drilling annulus sealing device 70, are disconnected from the drill string 20 and the unexpanded liner section 8. The drill string and tubular element 4  
25           typically extend at least partly into the wellbore 1. Herein, the drill string and the tubular element 4 may also extend from a rig on an offshore platform. When disconnected from the top drive 60, the drill string 20 will typically be held by a gripping device 272 to grip  
30           the drill string 20 in a relatively non-damaging manner and suspend it from the rig. The gripping device typically comprises three or more steel wedges or slips 274 that are hinged together, forming a near circle

around the drill string. On the drill string side, i.e. the inside surface, the slips 274 may be provided with replaceable, steel teeth that embed slightly into the surface of the pipe. The outsides of the slips are tapered to match a taper of a (false rotary) table 276.

In a second step, shown in Figures 14 to 16, the top drive 60 picks up the additional expandable pipe section 84. Picking up herein may indicate that the top drive is displaced and/or that the expandable pipe is moved towards the top drive, for instance by a pipe handling device such as device 260.

As an example, first the top drive 60 is lowered along the rails 256 (Fig. 14). After reaching a predetermined height (Fig. 15), the top drive 60 in combination with the sealing device 70 are rotated. While rotating the top drive, it is also lowered further until the connection part 62 and the stinger 100 are arranged within the pipe 84 (Fig. 16).

When the drilling annulus sealing device 70 contacts the pipe 84 in a predetermined way (Fig. 16), the grippers 106 are activated via hydraulic control line 88. Herein, the seals 80, 82 engage the outer surface of the pipe 84, whereas the stinger 100 is arranged within the pipe 84 and the corresponding seals 102, 104 and grippers 106 engage the inner surface of the pipe 84.

Thereafter, shown in Figures 17 and 18, the top drive 60 and the sealing device 70, including the additional expandable pipe 84, are moved upwards and rotated until reaching substantially the initial position (Fig. 18).

In a next step, the system of the invention picks up the additional drill string section 66. Picking up herein may indicate that the top drive is displaced and/or that the drill pipe section 66 is moved towards the top drive.

As shown in Fig. 18, first the arm 264 is displaced towards the drill pipe section 66, so that the grabbing element 266 can grab the drill pipe section 66. Then the arm 264 rotates around the column 262 to arrange the drill pipe section 66 between the drill string 20 and the connection part 62 (Fig. 19).

Now, shown in Fig. 20, the drill pipe section 66 is connected to the connection part 62, for instance by tightening the threaded connection 30 therebetween.

The top drive is subsequently lowered and the additional drill pipe section 66 is connected to the upper end of the drill string 20 (Fig. 21). This is done by tightening the threaded connection 30 therebetween, by causing the top drive to rotate the additional drill string section 66.

As shown in Figures 22 and 23, in a next step the drilling annulus sealing device is lowered with respect to the top drive 60, until the lower edge of the additional expandable tubular section 84 is in close proximity to the unexpanded liner section 8, or engages the unexpanded liner section 8. The sealing device can be lowered by extending the pistons 142 of hydraulic cylinders 136, such that the distance L3 increases.

Please note that the embodiment of Figure 5, wherein top drive 60 and sealing device 70 are fixedly connected, will operate in a different way. As the top drive and the sealing device 70 are fixed to each other, the drill string 20 will move up or down in correspondence with any vertical movements of the sealing device 70, once the additional drill string section 66 has been connected to the drill string 20.

In a next step (Fig. 23), the backing gas tool 192 may be activated to provide a suitable backing gas 210. A

suitable backing gas comprises for instance one or more noble gasses such as He, Ne, Ar, Kr and Xe. Then, the additional liner section 84 is welded to the unexpanded liner section 8, which is schematically indicated by sparks 212.

Suitable welding methods include for instance laser beam welding. Suitably, the laser may include an Nd:YAG laser or a CO<sub>2</sub> laser. A suitable laser welding method is described in for instance US-7150328-B2, which is incorporated herein with respect to laser beam welding.

Figure 24 shows the weld 214 which connects the additional expandable pipe section 84 to the unexpanded liner section 8. The mutual ends are typically round and flush, resulting in a circular weld 214. However, other pipe ends are conceivable.

Once the drilling annulus 32 is closed, drilling fluid can be pumped down a fluid channel (not shown) extending through the top drive 60, the connection part 62, the drill string 20 and the drill bit 22 into the wellbore 1. When the drilling fluid has reached the drill bit 22, said fluid will subsequently rise within the drilling annulus 32. The fluid will then enter the space 74 and drained via the conduit 90. While pumping drilling fluid, the top drive 60 is activated to rotate the drill string 20 and the drill bit 22, as indicated by arrow 280. Rotation can be clockwise or counter-clockwise. Due to the rotation of the drill bit 22, the wellbore is extended at its lower end and the bit, drill string and top drive move downwards, as indicated by arrow 282. Drilling continues until the wellbore 1 is extended over a predetermined length, which typically corresponds to the length of one or more drill pipe sections 28 and/or one or more expandable tubular sections 84.



Please note that drilling fluid can also be pumped vice versa, i.e. via the conduit 90 into the annulus 32 and via the drill bit, the drill string and the top drive.

5           While the top drive moves downwards with the bit, the sealing device may either stay stationary, move downwards in conjunction with the top drive, or move downwards at twice the speed of the top drive, or at any speed therein between. The upper end of unexpanded tubular section 8  
10           will move downward at the same speed as the sealing device 70, wherein the expanded tubular section 10 is extended at about half said speed at the downhole end of the tubular element.

15           If the sealing device 70 was moved downward at less than twice the speed of the top drive 60, the unexpanded liner section 8 can after drilling be forced into the expanded liner section 10 to evert the unexpanded section (Fig. 25). Forcing or pushing the unexpanded tubular  
20           section 8 downward can be achieved by extending the pistons 142, as shown by arrows 284. Herein, the drilling annulus sealing device 70 moves downward together with the unexpanded tubular section 8, while the top drive 60 remains stationary, so that the distance L3 increases.

25           When the wellbore is extended with said predetermined length, the top drive is pulled up, as shown in Figure 26 and indicated by arrow 286. The sealing device 70 may be held stationary, so that the distance L3 increases. The flow of drilling fluid may continue while pulling the top drive 60 up.

30           After pulling up the top drive 60 and before disconnecting the drilling annulus sealing device 70, a flow check may be included as a safety procedure. Flow check herein indicates comparing the input of drilling

fluid (through the drill string) to the output of drilling fluid (through the conduit 90). Said input and output should be more or less equal, within a predetermined safety range. Said safety range is for instance less than about  $\pm 1\%$  difference. In practice, the flow check may take in the order of about 1 to 5 minutes, typically about 2 minutes. The flow check, possibly in combination with other checks concerning pressure levels within the wellbore, may indicate irregularities, such as fluid loss to the formation or unwanted fluid influx into the wellbore. If alarmed, the operator may maintain the drilling annulus sealing device 70 to seal the drilling annulus 32 to be able to control the well and/or to execute further checks.

After passing the flow check, the sealing device 70 can be disconnected (Fig. 27). The grippers will be deactivated using the control line 88 and the device 70 can be lifted, as indicated by arrows 288. Herein, the top drive may be held stationary, so that distance L3 decreases.

After disconnecting the sealing device, the gripping device 272 is arranged to hold the drill string 20 (Fig. 28).

As a final step, shown in Figure 29, the connection part 62 is disconnected from the drill string and the assembly of top drive, connection part 62 and sealing device 70 is lifted to the initial position, as indicated by arrow 290. The rig 250 is subsequently prepared for the start of the cycle as shown in Figure 13.

The method of using the system of the present invention has been described above using an embodiment which combines the features as shown in Figures 4 and 9. The use is however not limited to said embodiment, and is

likewise possible using any other embodiment of the system. Each embodiment has specific features which may benefit in a specific situation. For instance, a combination of inner and outer seals for increased reliability may be preferred, or a stinger for easy alignment of the expandable pipes. Otherwise, seals and grippers on the outside of the expandable pipe leave a larger inner space 74, which may be beneficial for use in combination with smaller diameter expandable pipes. Small herein indicates, for instance, a diameter smaller than 9 5/8 or smaller than 7 inch. Otherwise, embodiments comprising less parts, or less movable parts may be preferred for cost reasons or to diminish maintenance requirements.

For instance, when using the sealing device 70 shown in Figure 2 the backing gas tool 92 can be arranged around the drill string before attaching the additional drill string section 66 to the drill string 20 (Fig. 30). Herein, the backing gas tool 92 can be used to provide backing gas for welding and/or to support alignment of the additional liner section 84 and the unexpanded liner section 8. Herein, the sealing elements 152-154 may engage with the upper end of the unexpanded section 10 to support the tool and to prevent it from falling into the wellbore.

At any convenient time before deployment, the internal pressure chamber 158 of the backing gas tool 92 is filled with a suitable backing gas 210 (Fig. 31). The valve 162 can be a two-way valve, so that the gas may be introduced into chamber 158 via the valve. The flexible balloon 160 will expand due to the increasing gas pressure in the chamber 158, thus providing a visible indication of said pressure. The outside surface of the

balloon 160 can for instance be provided with marks, to indicate an operator that the pressure has reached a predetermined preferred pressure range. Said marks may include a graphical representation or figure which is only correctly displayed when the pressure is in the predetermined range, for instance a circle, (equilateral) triangle, or (equilateral) polygon.

At any convenient time, the valve 162 of the backing gas tool is opened, so that the stretched flexible material of the expanded balloon will act on the gas 210 and force the backing gas to exit the pressure chamber via the valve (Fig. 31). Preferably, the chamber contains enough backing gas to last until the end of the welding process. Herein, said convenient time may be the time when the additional expandable tubular section 84 is adequately aligned with the unexpanded liner section 8, and both engage the respective outer seals 156, 154 of the tool 92 respectively.

Part of the backing gas 210, which is expelled through the valve 162, will be enclosed between the liner sections, the tool 92, the lower seal 154 and the upper seal 156. Lower sealing elements 152, 154 engage the drill string and inner wall of the tubular element 8 respectively, to maintain the tool 92 in its predetermined position.

During drilling, the drilling fluid will reached the lower seals 152, 154 of the backing gas tool 92 and the fluid will lift the tool upward until the tool enters the internal space 74 of the sealing device 70.

Figure 32 shows the system 300 for radially expanding the expandable tubular element 4 by eversion thereof. As an example, the system 300 includes the drilling annulus sealing device of Figure 4.

The system 300 includes an emergency blow-out preventer 302 for blocking the drilling annulus in case of an emergency, such as an otherwise uncontrollable blow-out of the wellbore. The emergency blow-out preventer comprises a housing 304 which encloses at least a part of the unexpanded tubular section 8. The housing is preferably located at surface to enable workers access to the device, but may also be located downhole or at the seabed in case of an offshore application.

The housing 304 may be attached to the sealing device 50. Herein, the sealing device 50 may function as a wellhead. Wellhead herein means the surface termination of the wellbore, and may incorporate facilities means of hanging the production tubing and installing a Christmas tree and surface flow-control facilities in preparation for the production phase of the well.

Optionally, and as shown in Figures 32 and 33, the housing 304 comprises multiple housing parts 306, 308, 310. Each housing part may comprise a different device or provide a different functionality. Respective housing parts are for instance cylindrically shaped, comprising flanges 312 at opposite ends. Adjacent housing parts can be mutually connected by connecting their respective flanges to each other, for instance by bolt-nut assemblies 314. The inside of each housing part may optionally be provided with upper and lower seals 316, 318 respectively, wherein each seal is adapted to be able to engage the unexpanded liner section 8. Each seal 316, 318 may include one, two or more seals, depending on local conditions, expected pressures, etc. The seals 316, 318 are for instance comparable with, or similar to the seals 56, 58 of the sealing device or wellhead 50.

In an embodiment, shown in Fig. 32, the emergency blow-out preventer 302 comprises a cutter 320. The cutter is located in a lower part of the housing 304, for instance in first housing part 306. In addition the emergency blow-out preventer 302 comprises one or more ram-type preventers 322, 324 for closing off the annulus 32, which are arranged above the cutter 320. The ram type preventers for instance include a pipe ram 322 and a shear ram 324. The pipe ram can comprise two opposite ram blocks 226 which can close around the drill string 20. The shear ram can comprise two opposite shear ram blocks 228 which can cut through the drill string. The housing 304 may include one, two or more of each ram type preventer, to improve reliability and fail-safety.

In another embodiment, shown in Fig. 33, the emergency blow-out preventer 302 comprises a cutter 320. An annular preventer 330 is arranged above the cutter. The annular preventer comprises for instance one or more inflatable packer elements 332 that can close around the drill string 20. The packer elements can be inflated with pressurized fluid. The emergency blow-out preventer 302 also comprises the shear ram 324.

A fluid conduit or kill line 334 connects the drilling annulus 32 below the lowest ram type preventer with an external pump system (not shown). Fluid, typically mud or heavy drilling fluid, can be circulated via the drill string and the drilling annulus 32, indicated by arrows 336 and 338 respectively, and through the kill line 334, or vice versa.

The ram type preventers are devices that can be used to quickly seal the top of the wellbore in the event of a well control event, also known as a kick. The ram type preventer may comprise two halves of a cover for the well

that are split down the middle. Said halves can be driven by hydraulic cylinders (not shown), which are normally retracted and can force the two halves of the cover together in the middle to seal the wellbore (as shown in Figs. 32 and 33). These covers are for instance constructed of steel for strength and may be fitted with elastomer components on the sealing surfaces. The halves of the covers, also called ram blocks, may have a variety of configurations.

In case of the pipe ram 322, the ram blocks 326 may have a circular cutout 340 in the middle that corresponds to the diameter of the pipe in the wellbore, for instance enabling them to seal around the drill pipe 20. Variable-bore rams (not shown) and inflatable packers 332 are designed to seal a wider range of pipe diameters. Shear ram blocks 328 are fitted with a cutting surface to enable the ram blocks to completely shear through the drill pipe 20 (as schematically shown in Figures 32 and 33), hang the drill string off on the ram blocks themselves and seal the wellbore. Shearing the drill string limits future options and is employed only as a last resort to regain pressure control of the wellbore.

The various ram blocks can be changed in the ram type preventers, enabling an operator to optimize the configuration of the emergency blow-out preventer 302 for the particular wellbore section or operation in progress.

In an exemplary embodiment, the cutter 320 comprises a guide ring 342 for enclosing the unexpanded section 8 and a cutting wheel 344 which can rotate along said guide ring around the unexpanded tubular section. The cutting wheel herein can be moved from a first position wherein the cutting wheel is radially retracted to a second

position wherein the cutting wheel touches the outside of the unexpanded tubular section 8.

In other embodiments, the cutter 320 may comprise a laser cutter and/or a blade which can be mounted on the guide ring 342. Other options may include a pressurized water cutter or a cutting rope which can engage the outer surface of the pipe.

In a practical embodiment, the diameter and/or wall thickness of the liner 4 can be selected such that the expanded liner section 10 is pressed against the wellbore wall 14 during the expansion process. The expanded liner 10 may thus seal against the wellbore wall and/or stabilize the wellbore wall.

The wall thickness of the liner 4 may be equal to or thicker than about 2 mm (0.08 inch). The wall of the liner 4 may be for instance more than 2.5 mm thick, for instance about 3 to 30 mm thick or about 3.2 to 10 mm. The outer diameter of the unexpanded section may be larger than 50 mm (2 inch), for instance in the range of about 50 to 400 mm (16 inch). The expanded section may have any outer diameter suitable for or commonly used in hydrocarbon production. Additionally, the wall of the liner may comprise a relatively strong material, such as a metal or preferably steel, or be made of solid metal or steel. Such steel may include low carbon steel, for instance comprising less than 0.3% carbon. Thus, the liner 4 can be designed to have adequate collapse strength to support a wellbore wall and/or to withstand internal or external pressures encountered when drilling for hydrocarbon reservoirs.

The length and hence the weight of the unexpanded liner section 8 will gradually increase during extension of the wellbore. Hence, the downward force exerted by the



pushing device 50 can be gradually decreased in  
correspondence with the increasing weight of unexpanded  
liner section 8. As said weight increases, the downward  
force eventually may need to be replaced by an upward  
5 force to maintain the total force within a predetermined  
range. This may prevent buckling of liner section 8.

During drilling, the unexpanded liner section 8  
proceeds into the wellbore while the drill string 20 also  
gradually proceeds into the wellbore 1. The unexpanded  
10 liner section 8 is moved downward at substantially the  
same speed as the drill string 20, so that the bending  
zone 14 remains at a relatively short distance above the  
drill bit 22. Herein, said short distance indicates the  
so-called open hole section L1 (see Fig. 1), i.e. the  
15 unlined section, of the wellbore 1. The method of the  
present invention enables the open hole section to have a  
length L1 smaller than about 100 metres, or smaller than  
50 metres at all times while drilling the wellbore.

The unexpanded liner section 8 may be supported by  
20 the drill string 20, for example by means of a bearing  
device (not shown) connected to the drill string, which  
supports the U-shaped lower section 12. In that case the  
upward force is suitably applied to the drill string 20,  
and then transmitted to the unexpanded liner section 8  
25 through the bearing device. Furthermore, the weight of  
the unexpanded liner section 8 then can be transferred to  
the drill string and utilised to provide a thrust force  
to the drill bit 22.

Drilling fluid containing drill cuttings is  
30 discharged from the wellbore 1 via outlet conduit 90.  
Alternatively, drilling fluid may be circulated in  
reverse circulation mode wherein the drilling fluid is  
pumped into the wellbore via the conduit 90 and

discharged from the wellbore via the drill string 20. Reverse circulation is most suited for use in combination with the embodiments shown in Figures 3 and 4.

When it is required to retrieve the drill string 20 to surface, for example when the drill bit 22 is to be replaced or when drilling of the wellbore 1 is complete, the reamer section 26 can be collapsed to its radially retracted mode, wherein the radial diameter is smaller than the internal diameter of the unexpanded liner section 8. Subsequently, the drill string 20 can be retrieved through the unexpanded liner section 8 to surface.

With the wellbore system of the invention, it is achieved that the wellbore is progressively lined with the everted liner directly above the drill bit, during the drilling process. As a result, there is only a relatively short open-hole section L1 of the wellbore during the drilling process at all times. Advantages of a short open hole section include limited possibility of influx into the wellbore, which will minimize the resulting pressure increase and simplify well control. The advantages of such short open-hole section will be most pronounced during drilling into a hydrocarbon fluid containing layer of the earth formation. In view thereof, for many applications it will be sufficient if the process of liner eversion during drilling is applied only during drilling into the hydrocarbon fluid reservoir, while other sections of the wellbore are lined or cased in conventional manner. Alternatively, the process of liner eversion during drilling may be commenced at surface or at a selected downhole location, depending on circumstances.

In view of the short open-hole section during drilling, there is a significantly reduced risk that the wellbore fluid pressure gradient exceeds the fracture gradient of the rock formation, or that the wellbore fluid pressure gradient drops below the pore pressure gradient of the rock formation. Therefore, considerably longer intervals can be drilled at a single nominal diameter than in a conventional drilling practice wherein casings of stepwise decreasing diameter must be set at selected intervals.

Also, if the wellbore is drilled through a shale layer, such short open-hole section eliminates possible problems due to a heaving tendency of the shale.

After the wellbore has been drilled to the desired depth and the drill string has been removed from the wellbore, the length of unexpanded liner section that is still present in the wellbore can be left in the wellbore or it can be cut-off from the expanded liner section and retrieved to surface.

In case the length of unexpanded liner section is left in the wellbore, there are several options for completing the wellbore. These are, for example, as outlined below.

A) A fluid, for example brine, is pumped into the blind annulus 44 between the unexpanded and expanded liner sections so as to pressurise the annulus and increase the collapse resistance of the expanded liner section 10. Optionally one or more holes are provided in the U-shaped lower section 12 to allow the pumped fluid to be circulated.

B) A heavy fluid is pumped into the blind annulus 44 so as to support the expanded liner section 10 and increase its collapse resistance.

C) Cement is pumped into the blind annulus 44 in order to create, after hardening of the cement, a solid body between the unexpanded liner section 8 and the expanded liner section 10. The cement may expand upon hardening.

5 D) The unexpanded liner section is radially expanded (i.e. clad) against the expanded liner section, for example by pumping, pushing or pulling an expander through the unexpanded liner section.

10 In the above examples, expansion of the liner is started at surface or at a downhole location. In case of an offshore wellbore wherein an offshore platform is positioned above the wellbore, it may be advantageous to start the expansion process at the offshore platform, at or above the water surface. Herein, the bending zone  
15 moves from the offshore platform to the seabed and subsequently into the wellbore. Thus, the resulting expanded tubular element not only forms a liner in the wellbore, but also a riser extending from the offshore platform to the seabed. The need for a separate riser is  
20 thereby obviated.

Furthermore, conduits such as electric wires or optical fibres for communication with downhole equipment can be extended in the annulus between the expanded and unexpanded sections. Such conduits can be attached to the  
25 outer surface of the tubular element before expansion thereof. Also, the expanded and unexpanded liner sections can be used as electricity conductors to transfer data and/or power downhole.

30 Since any length of unexpanded liner section that is still present in the wellbore after completion of the eversion process, will be subjected to less stringent loading conditions than the expanded liner section, such length of unexpanded liner section may have a smaller

wall thickness, or may be of lower quality or steel grade, than the expanded liner section. For example, it may be made of pipe having a relatively low yield strength or relatively low collapse rating.

5           Instead of leaving a length of unexpanded liner section in the wellbore after the expansion process, the entire liner can be expanded with the method described above so that no unexpanded liner section remains in the wellbore. In such case, an elongate member, for example a  
10       pipe string, can be used to exert the necessary downward force to the unexpanded liner section during the last phase of the expansion process.

          In order to reduce friction forces between the unexpanded and expanded liner sections during the  
15       expansion process, a friction reducing layer, such as a Teflon layer, may be applied between the unexpanded and expanded liner sections. For example, a friction reducing coating can be applied to the outer surface of the unexpanded section 8. The friction reducing layer reduces  
20       the annular clearance between the unexpanded and expanded sections, reducing tendency of the unexpanded section to buckle. Instead of, or in addition to, the friction reducing layer, centralizing pads and/or rollers can be applied in the blind annulus between the unexpanded and  
25       expanded sections to reduce the friction and the annular clearance.

          Instead of expanding the expanded liner section against the wellbore wall (as described), the expanded liner section can be expanded against the inner surface  
30       of another tubular element, e.g. casing or a liner, already present in the wellbore.

          Although the embodiments of the invention have been described including a top drive, the present invention is

likewise suitable for use with alternative drilling systems. The latter may include for instance a downhole motor instead of a top drive. Said downhole motor is a drilling tool comprised in the drill string directly  
5 above the bit. Activated by pressurized drilling fluid, it causes the bit to turn while the drill string remains fixed. Examples of the downhole motor include a positive-displacement motor and a downhole turbine motor.

The present invention is likewise suitable for  
10 directional drilling, i.e. drilling wherein the drilling direction can be adjusted. For instance, a downhole motor may be used as a deflection tool in directional drilling, where it is made up between the bit and a bent sub, or the housing of the motor itself may be bent.

15 The present invention is not limited to the above-described embodiments thereof, wherein various modifications are conceivable within the scope of the appended claims. For instance, features of respective embodiments may be combined.

C L A I M S

1. A system for lining a wellbore, the system comprising:

- a drill string for drilling the wellbore;
- an expandable tubular element enclosing the drill string, wherein a lower end portion of a wall of the expandable tubular element is bent radially outward and in axially reverse direction to define an expanded tubular section extending around an unexpanded tubular section;

- a pushing device for pushing the expanded tubular section into the expanded tubular section;
- a releasable drilling annulus sealing device for closing an annular opening between an upper end of the expandable tubular element and the drill string.

2. The system of claim 1, wherein the expandable tubular element comprises a plurality of interconnected tubular sections.

3. The system of claim 2, wherein respective ends of the interconnected tubular sections are connected to each other by a weld.

4. The system of claim 1, wherein the drill string comprises a plurality of interconnected pipe sections, and wherein an upper end of the drill string is connected to an upper end connection part.

5. The system of claim 4, wherein the drilling annulus sealing device is fixated with respect to the upper end connection part.

6. The system of claim 4, wherein the drilling annulus sealing device is moveable with respect to the upper end connection part.

7. The system of claim 1, wherein the drilling annulus sealing device encloses an upper end of the unexpanded tubular section.

8. The system of claim 1, wherein the drilling annulus sealing device comprises a stinger which projects into the unexpanded tubular section.

9. The system of claim 1, wherein the drilling annulus sealing device comprises at least one of a gripper for gripping the tubular element, one or more seals for sealing the annular opening, and a control line for activating the gripper and/or the one or more seals.

10. The system of claim 1, comprising a gas tool which is arranged around the drill string for providing backing gas for welding an additional tubular section to the upper end of the unexpanded tubular section.

11. The system of claim 10, wherein the gas tool is integrated in the stinger of the drilling annulus sealing device.

12. The system of claim 1, comprising an emergency shut-off device which is movably arranged around the unexpanded tubular section for closing a gap between the additional tubular section and the unexpanded tubular section.

13. The system of claim 1, comprising a blow-out preventer for closing off the wellbore in case of an emergency, wherein the blow-out preventer encloses the unexpanded tubular section and comprises:

- a cutter for cutting the unexpanded tubular section; and

- at least one closure device for closing the wellbore.

14. The system of claim 13, wherein the blow-out preventer is arranged on top of a blind annulus sealing device.



15. Method for lining a wellbore using the system of any of the previous claims.

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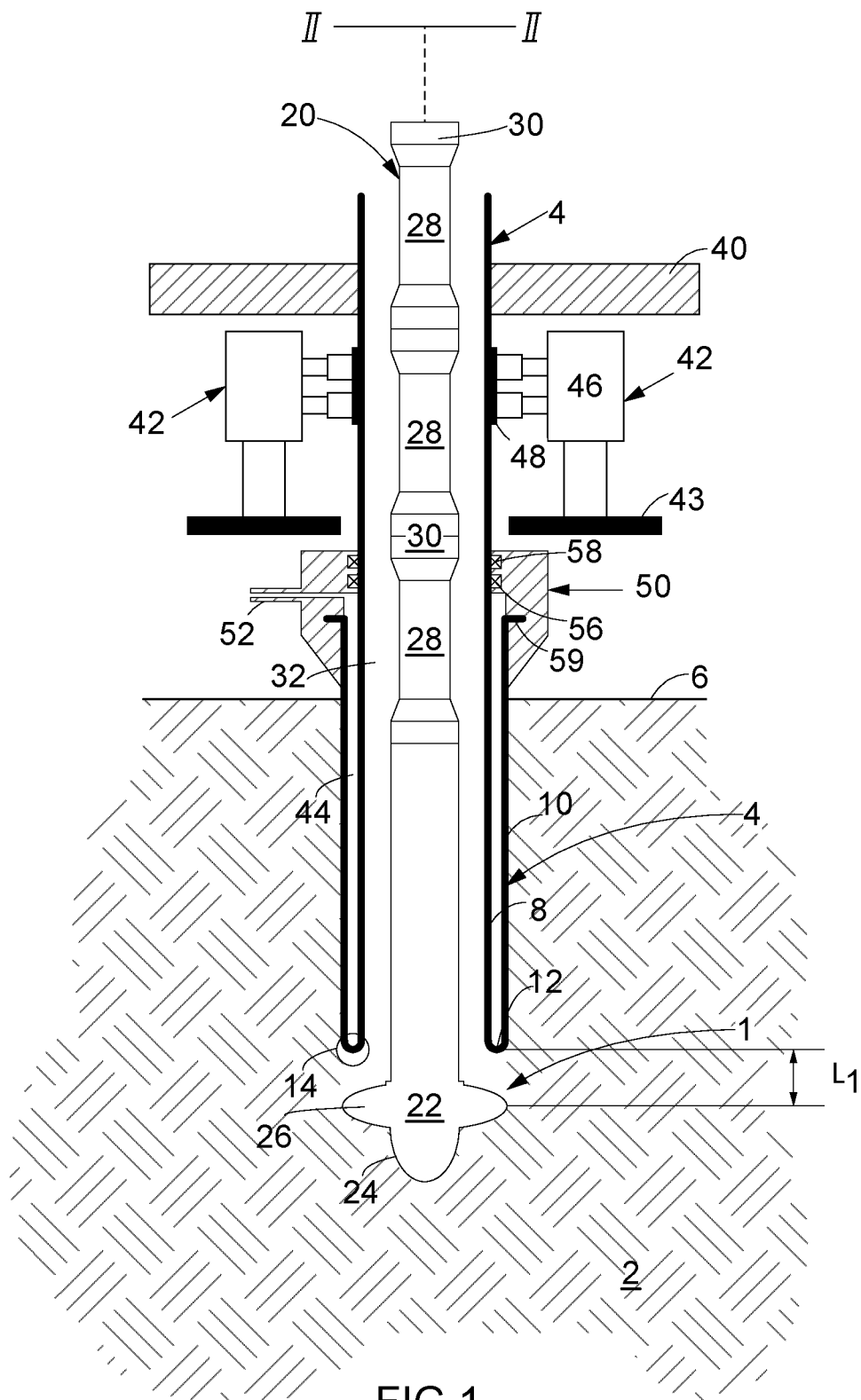


FIG. 2

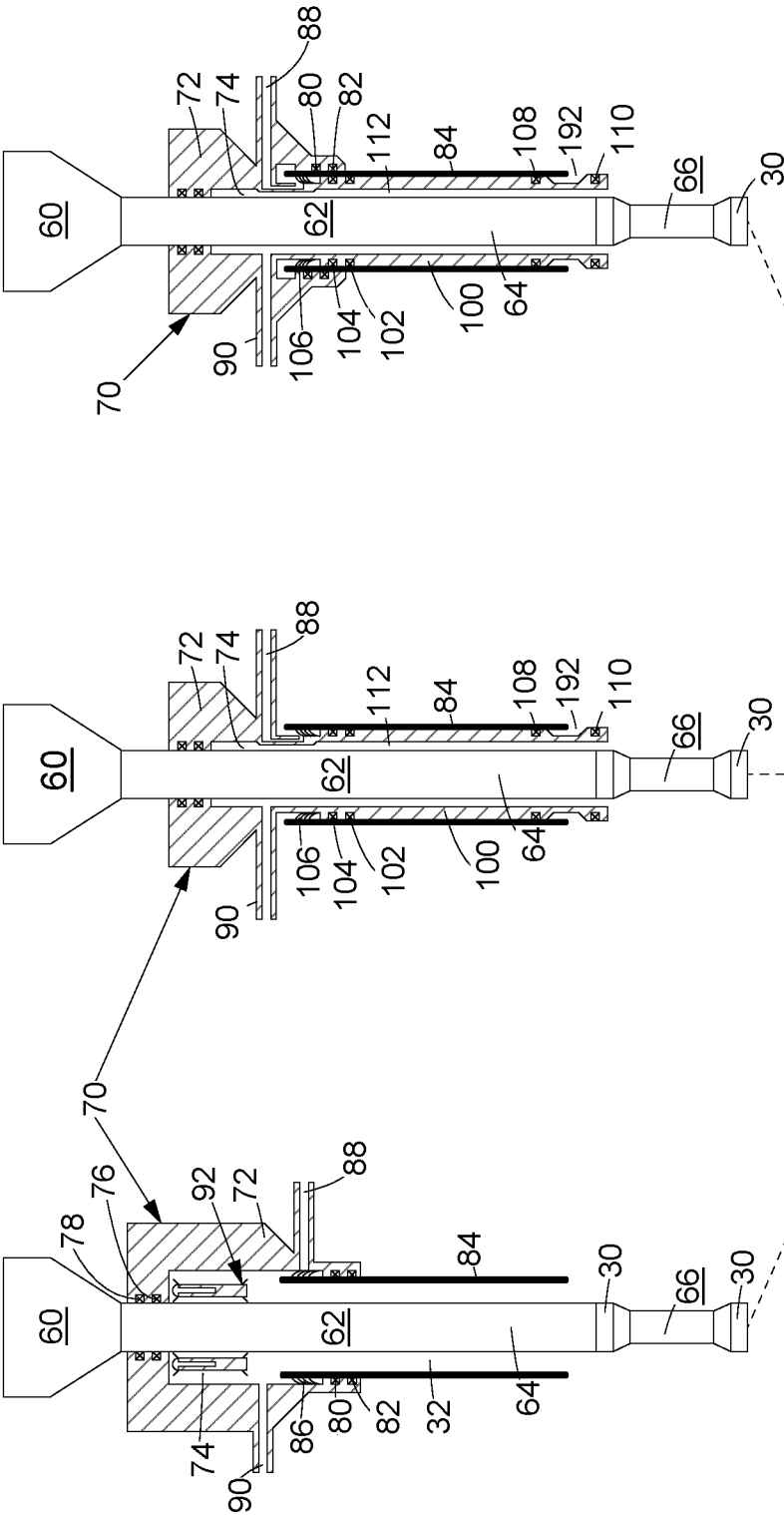


FIG. 3

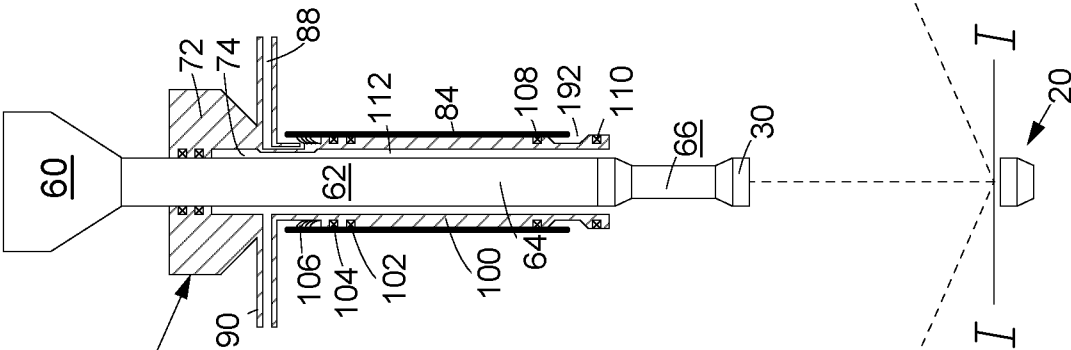
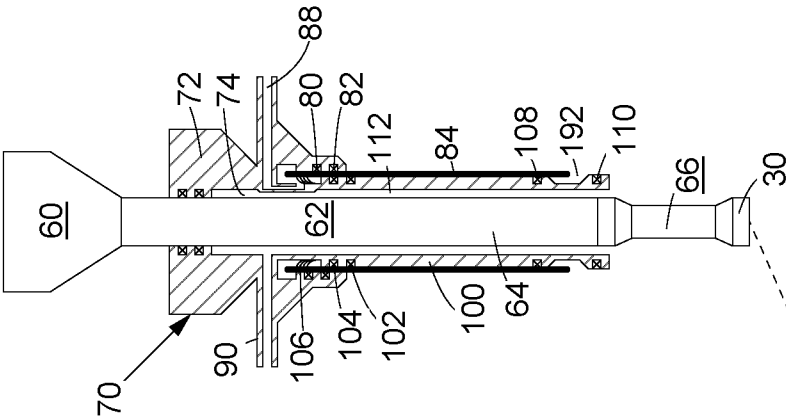


FIG. 4



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FIG. 5

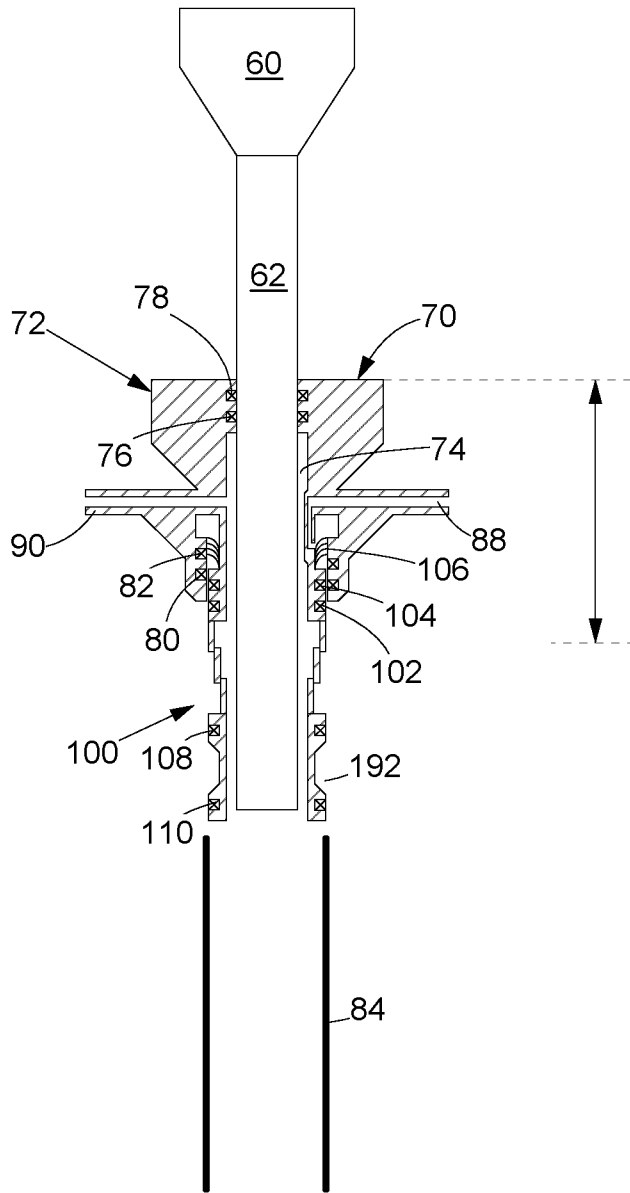


FIG. 6

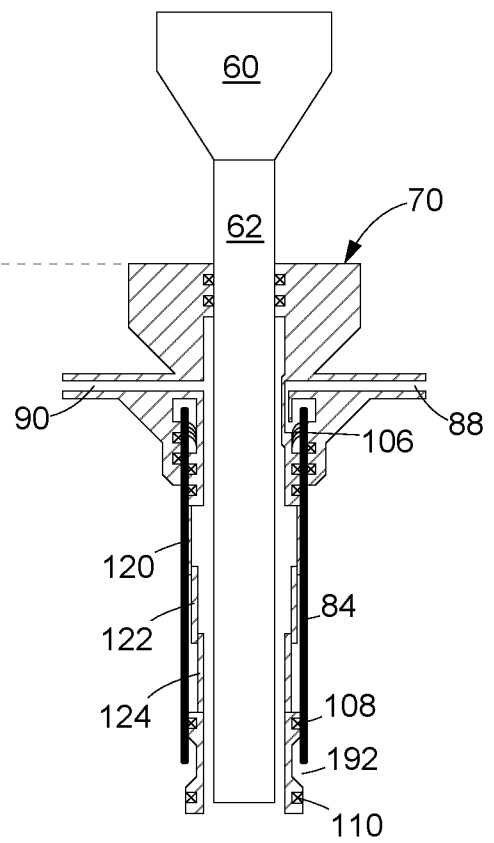


FIG. 9

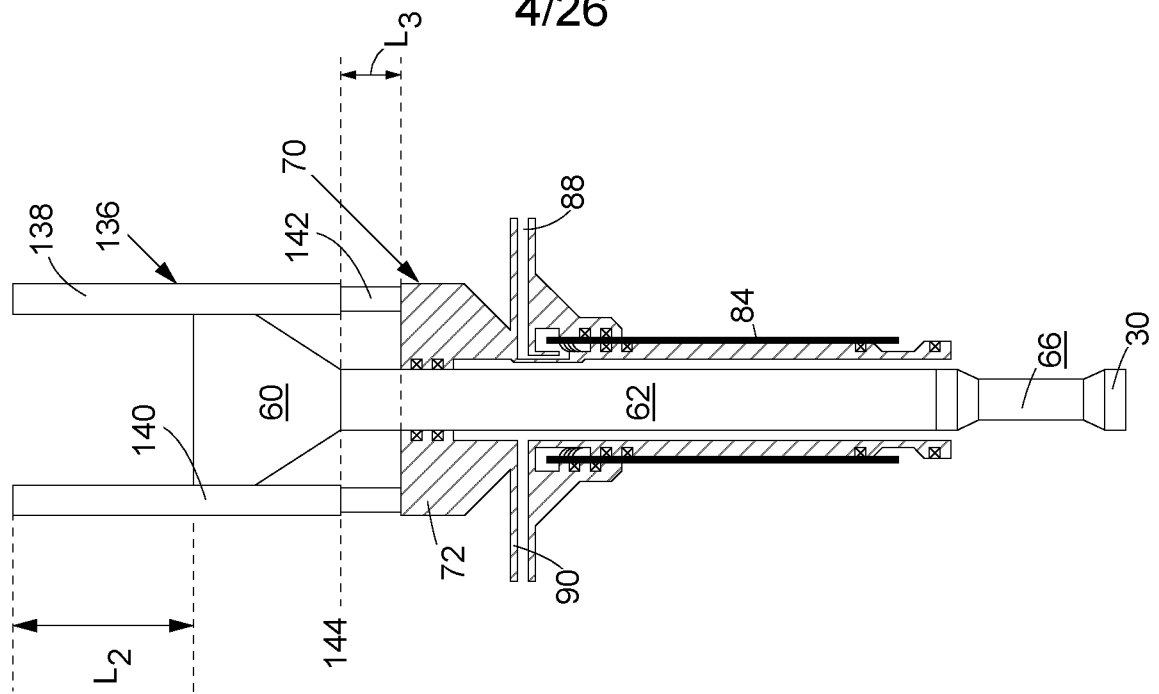
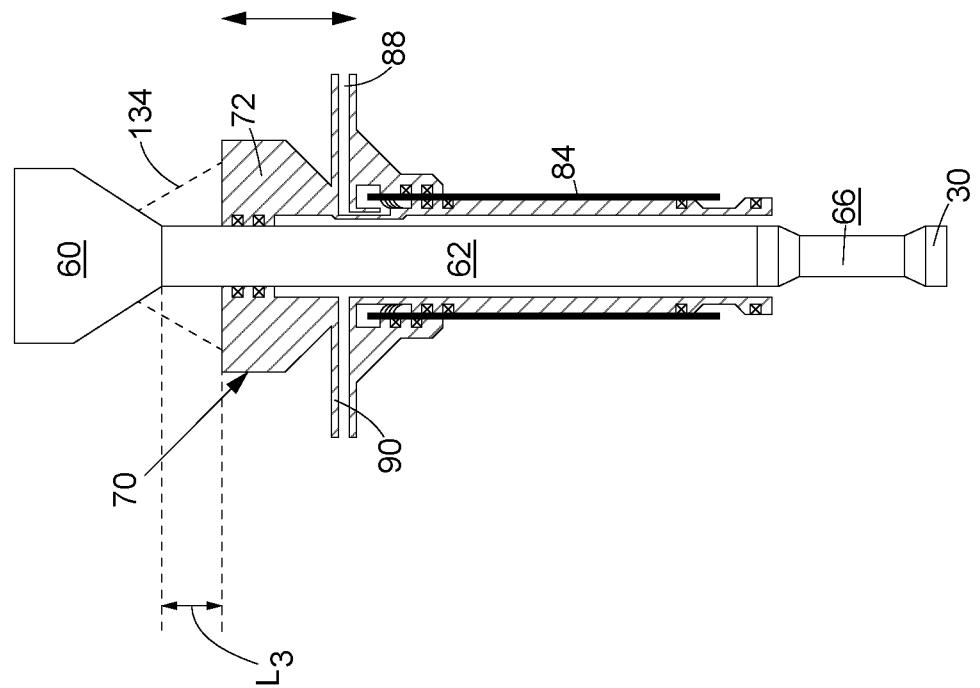
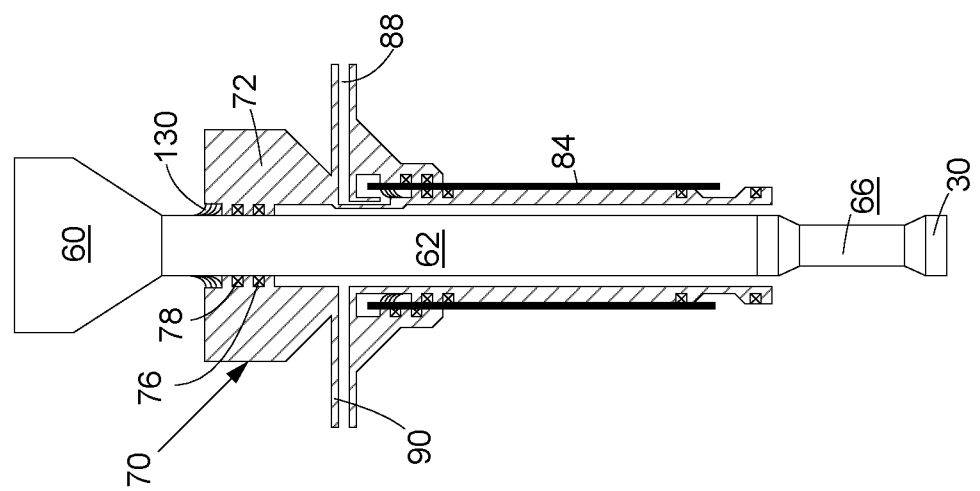
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FIG. 7



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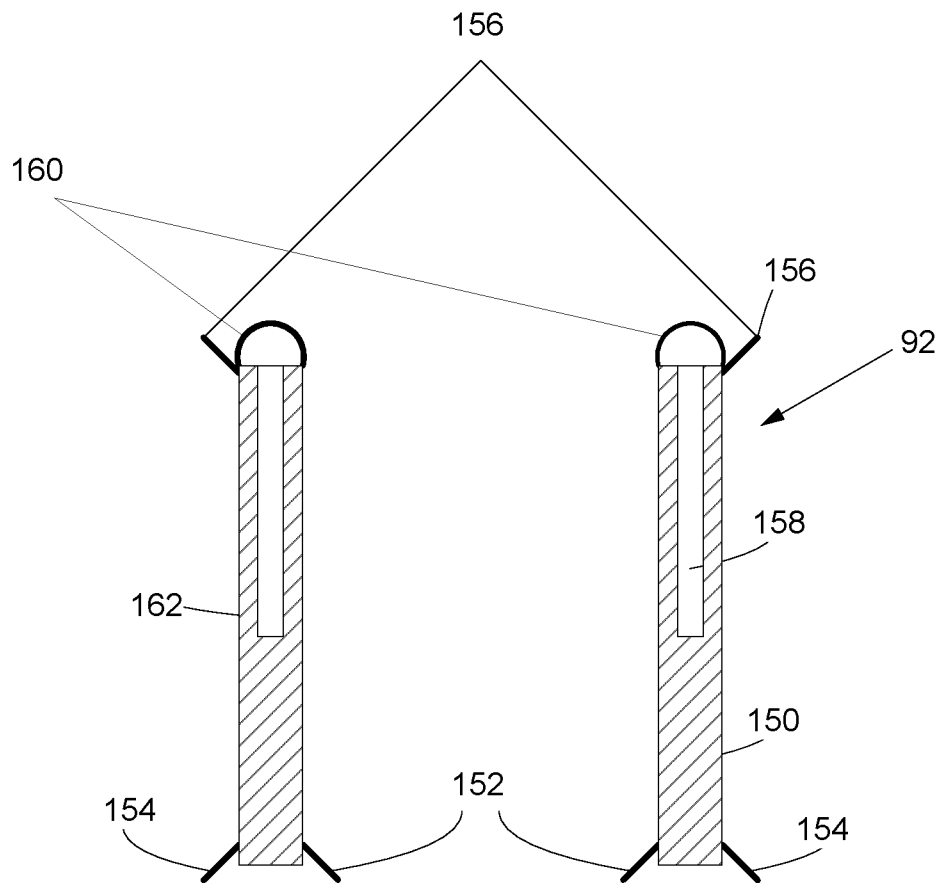


FIG. 10

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FIG. 11

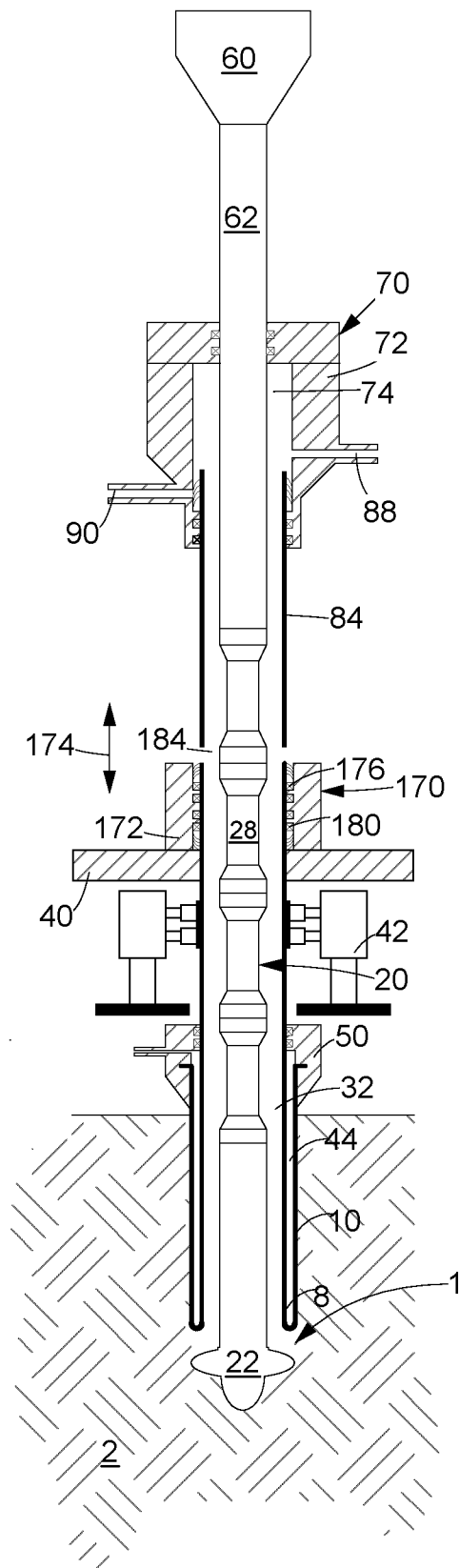
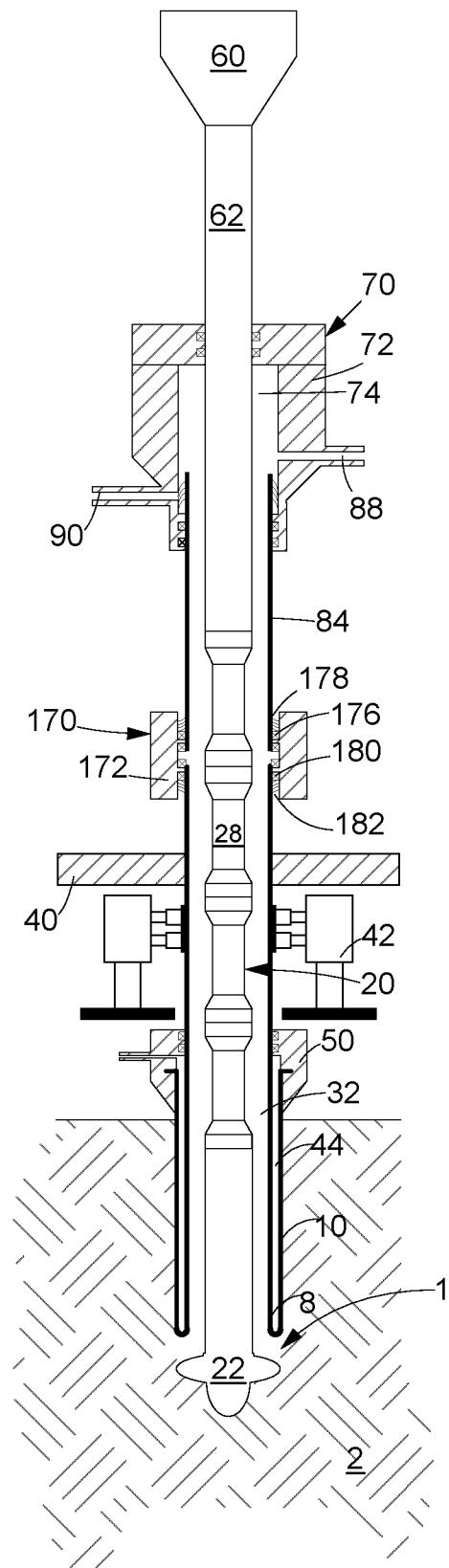


FIG. 12

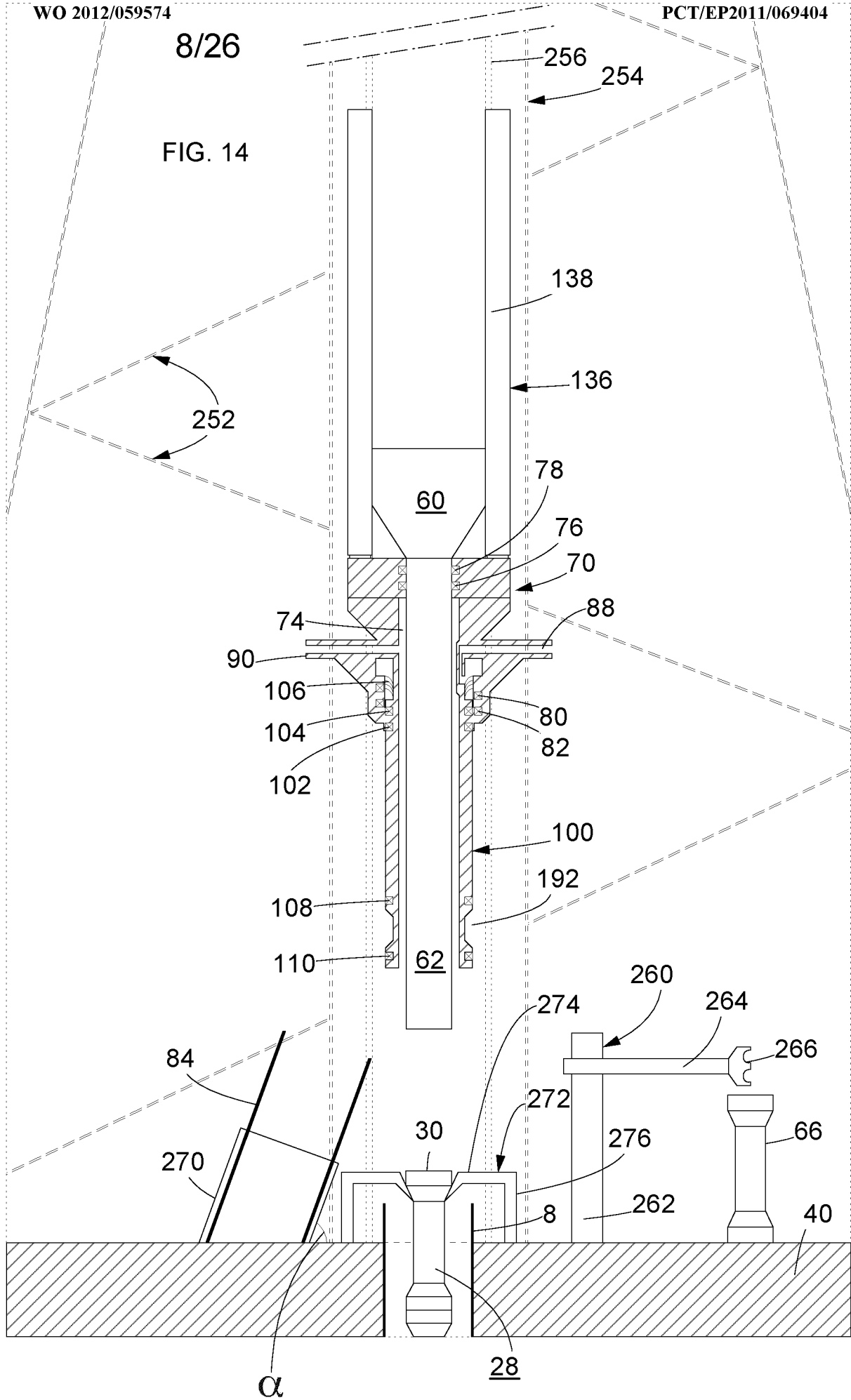






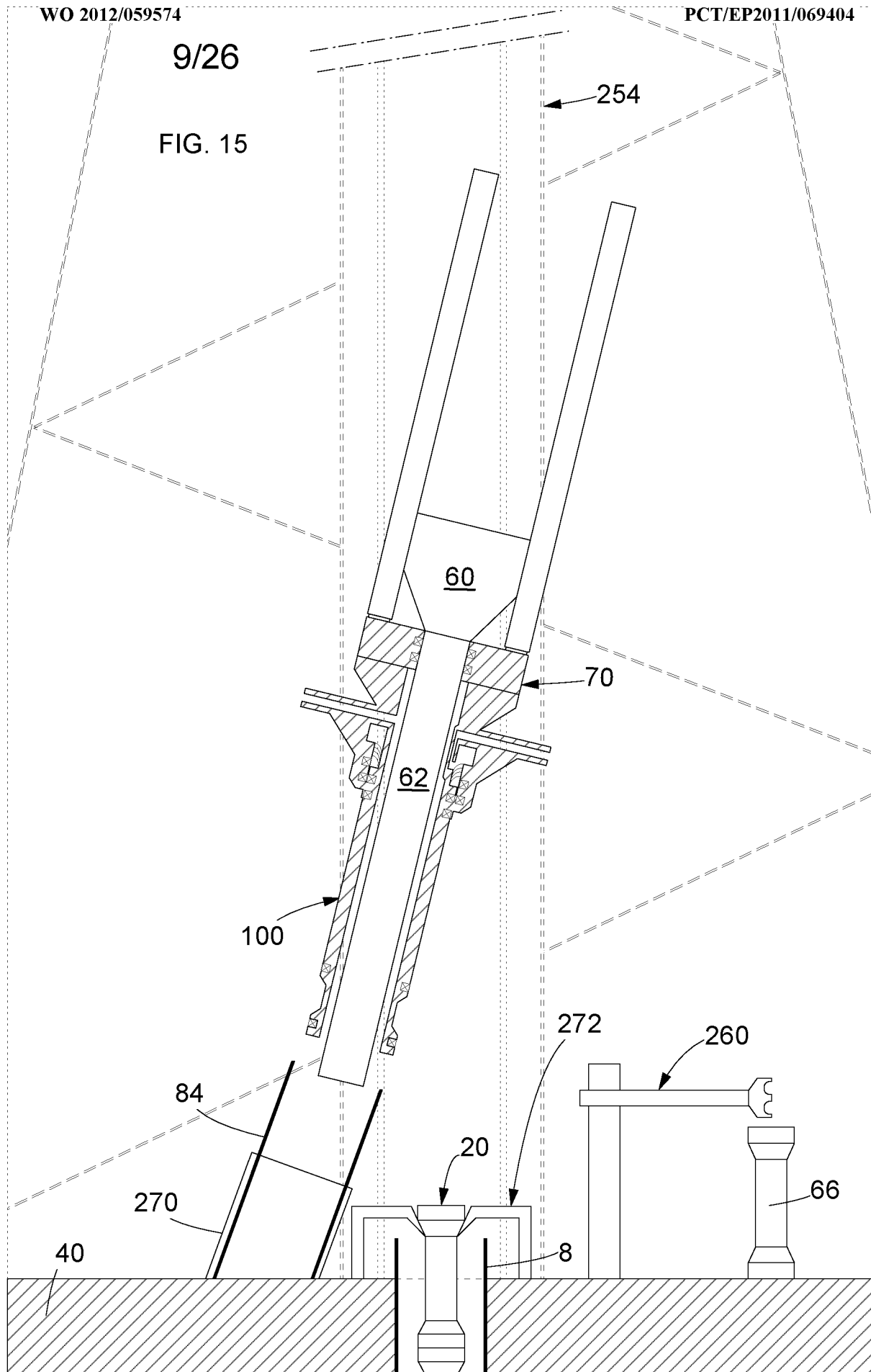
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FIG. 14



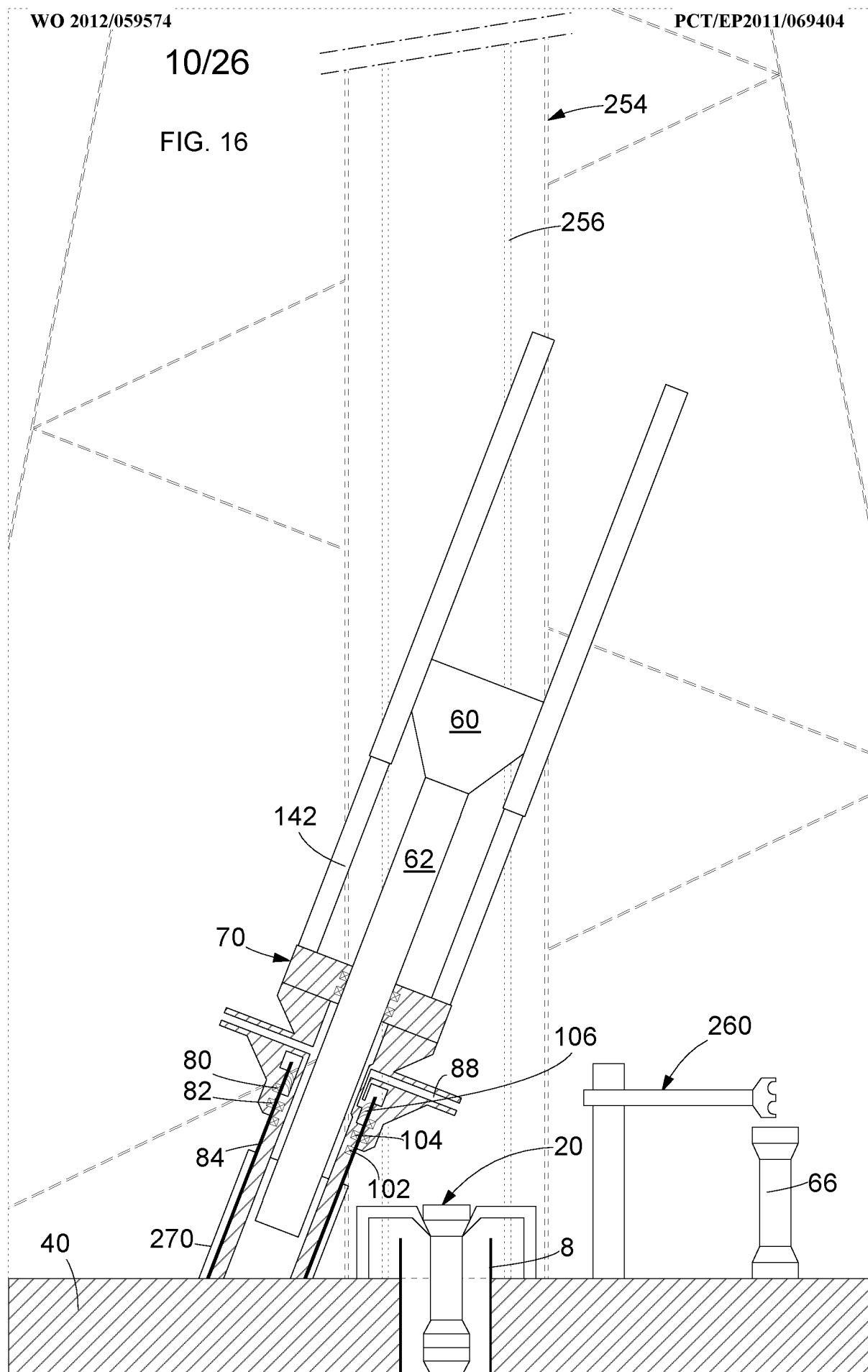
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FIG. 15



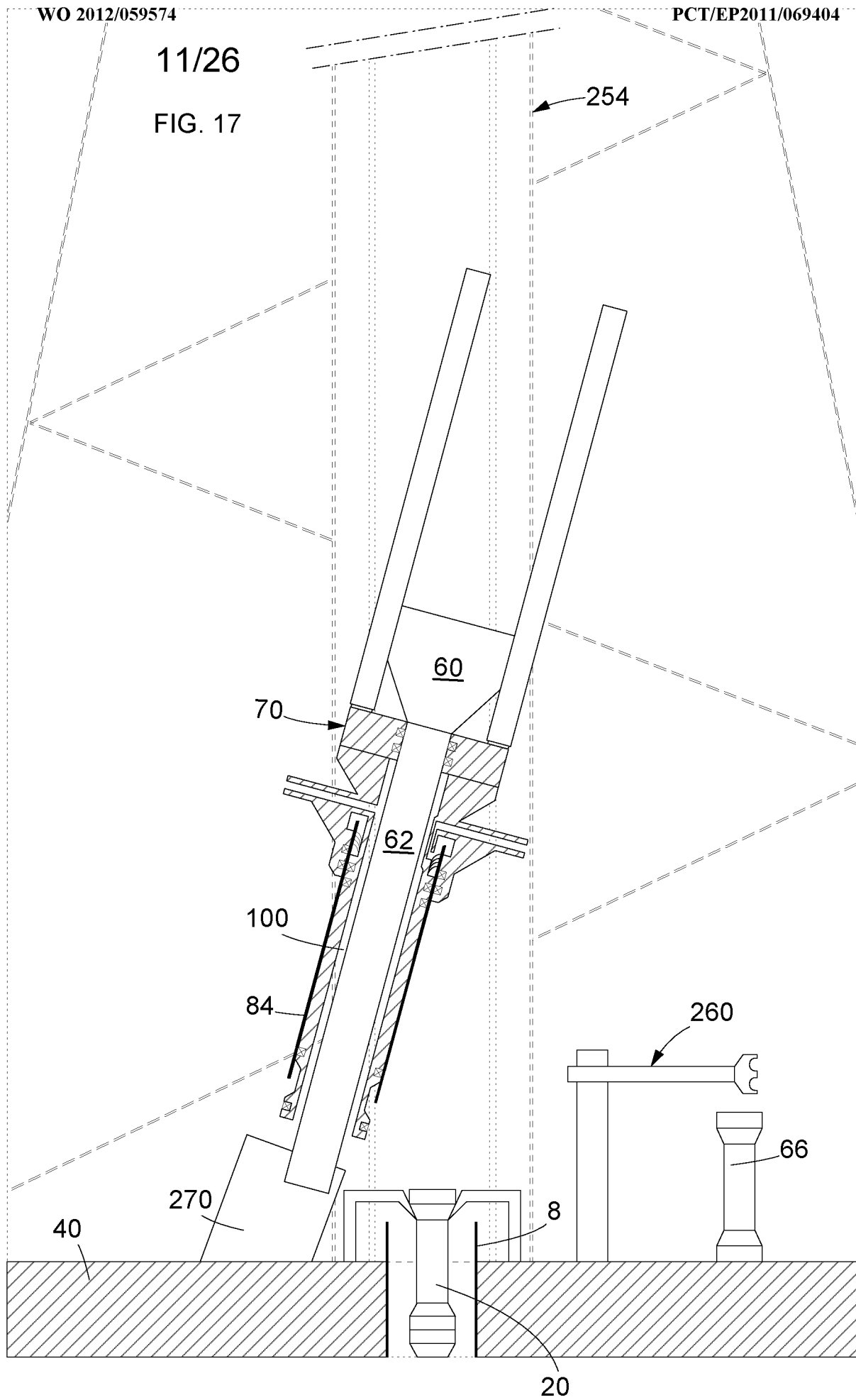
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FIG. 16



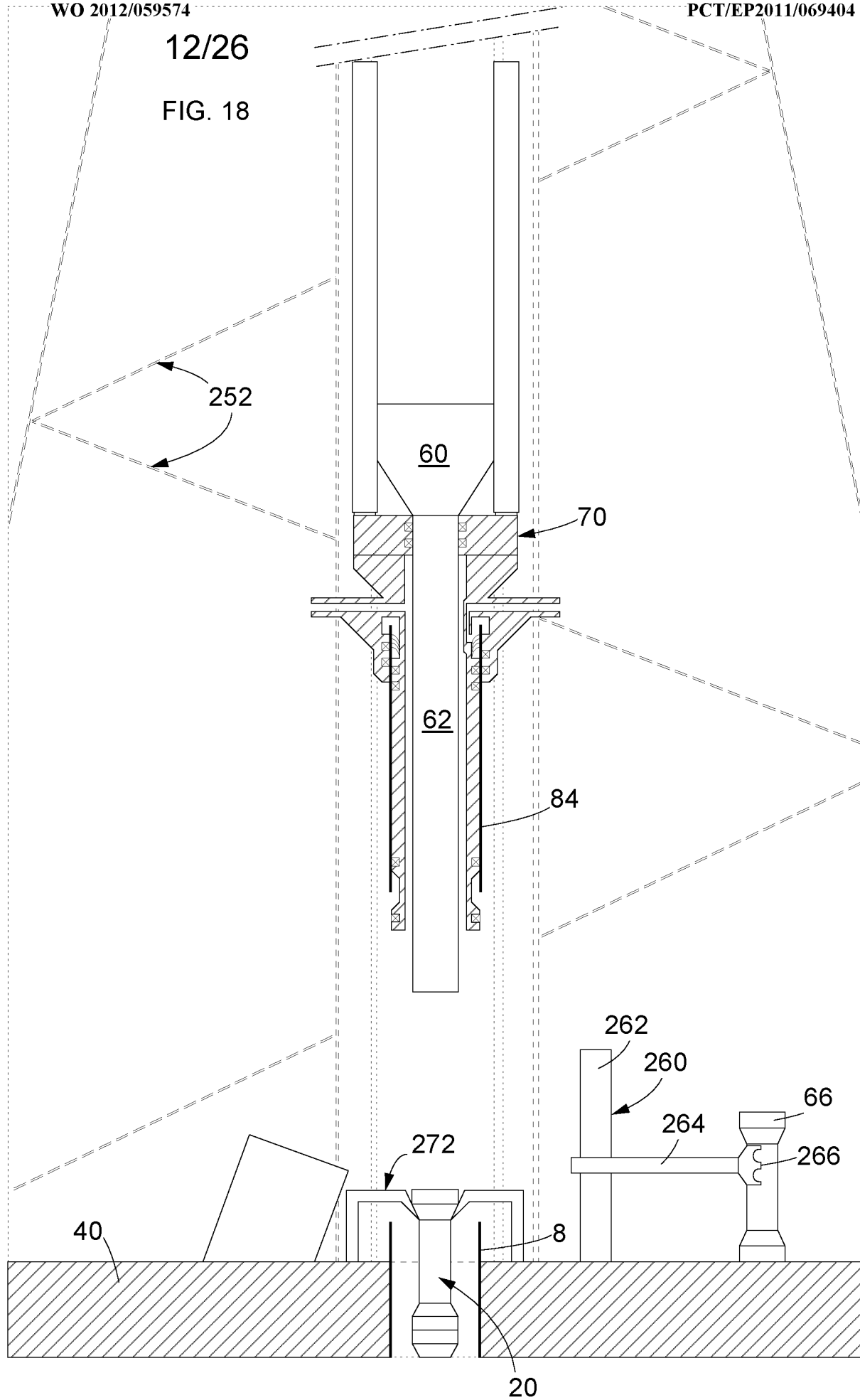
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FIG. 17



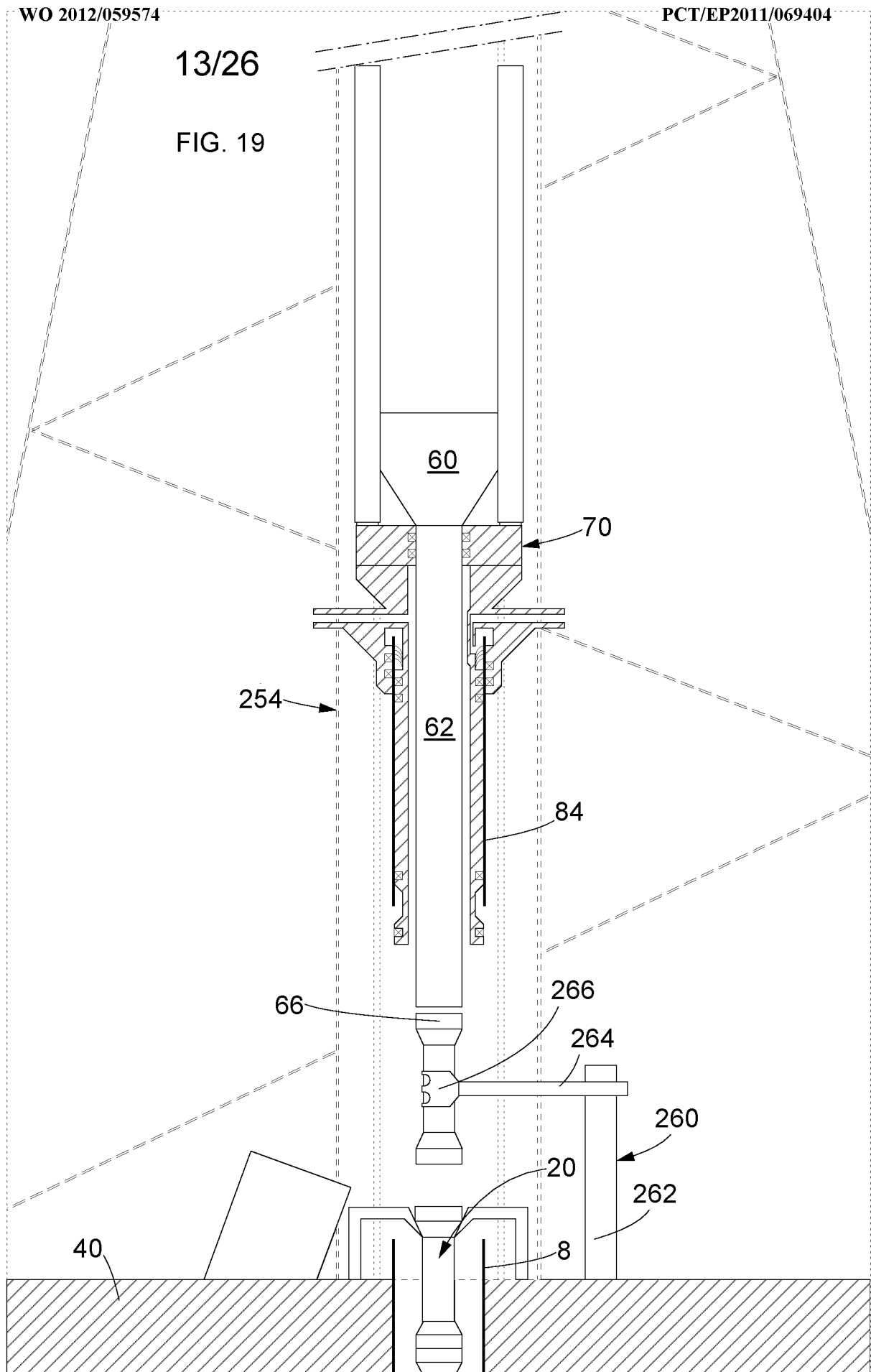
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FIG. 18



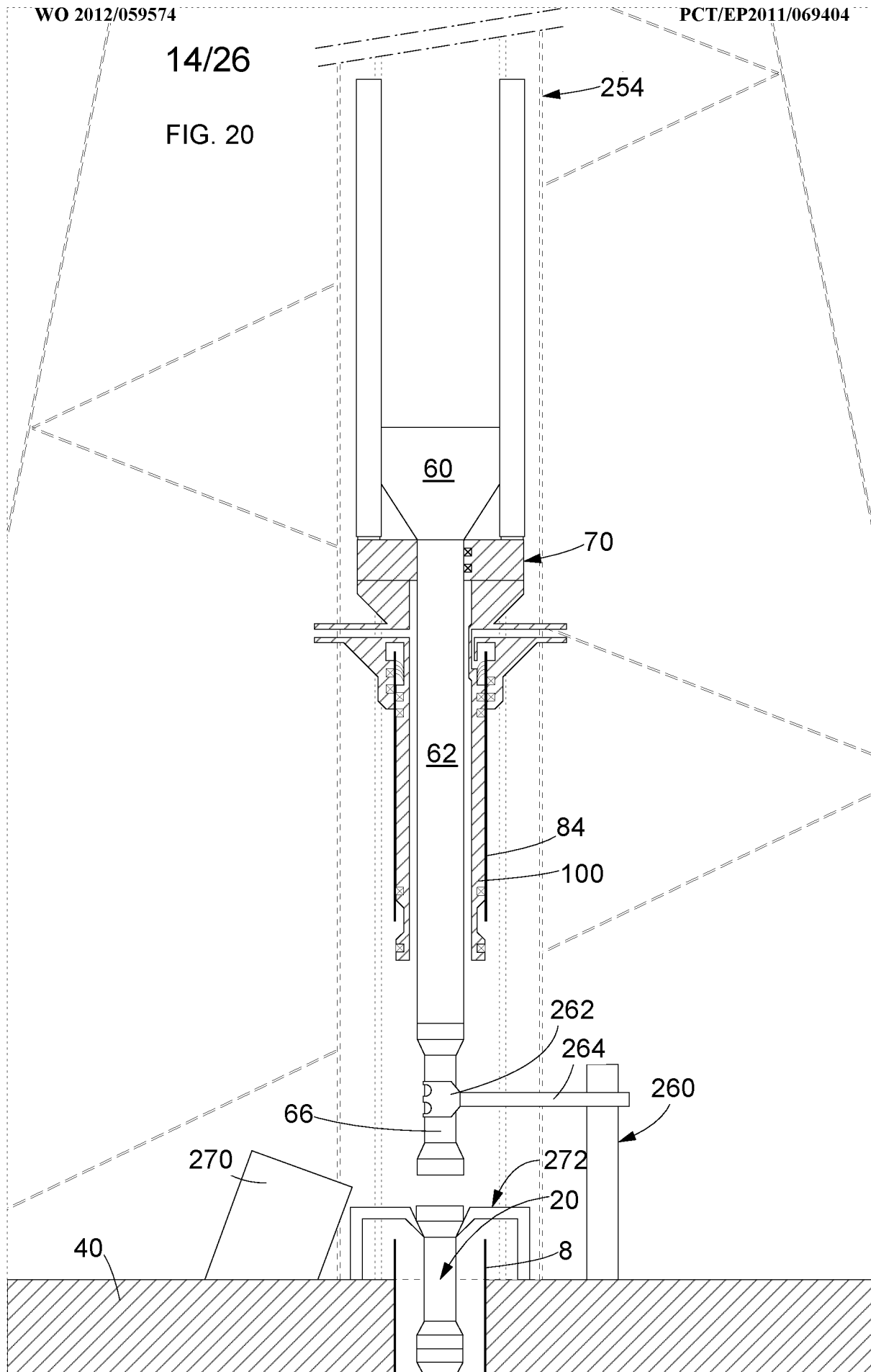
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FIG. 19



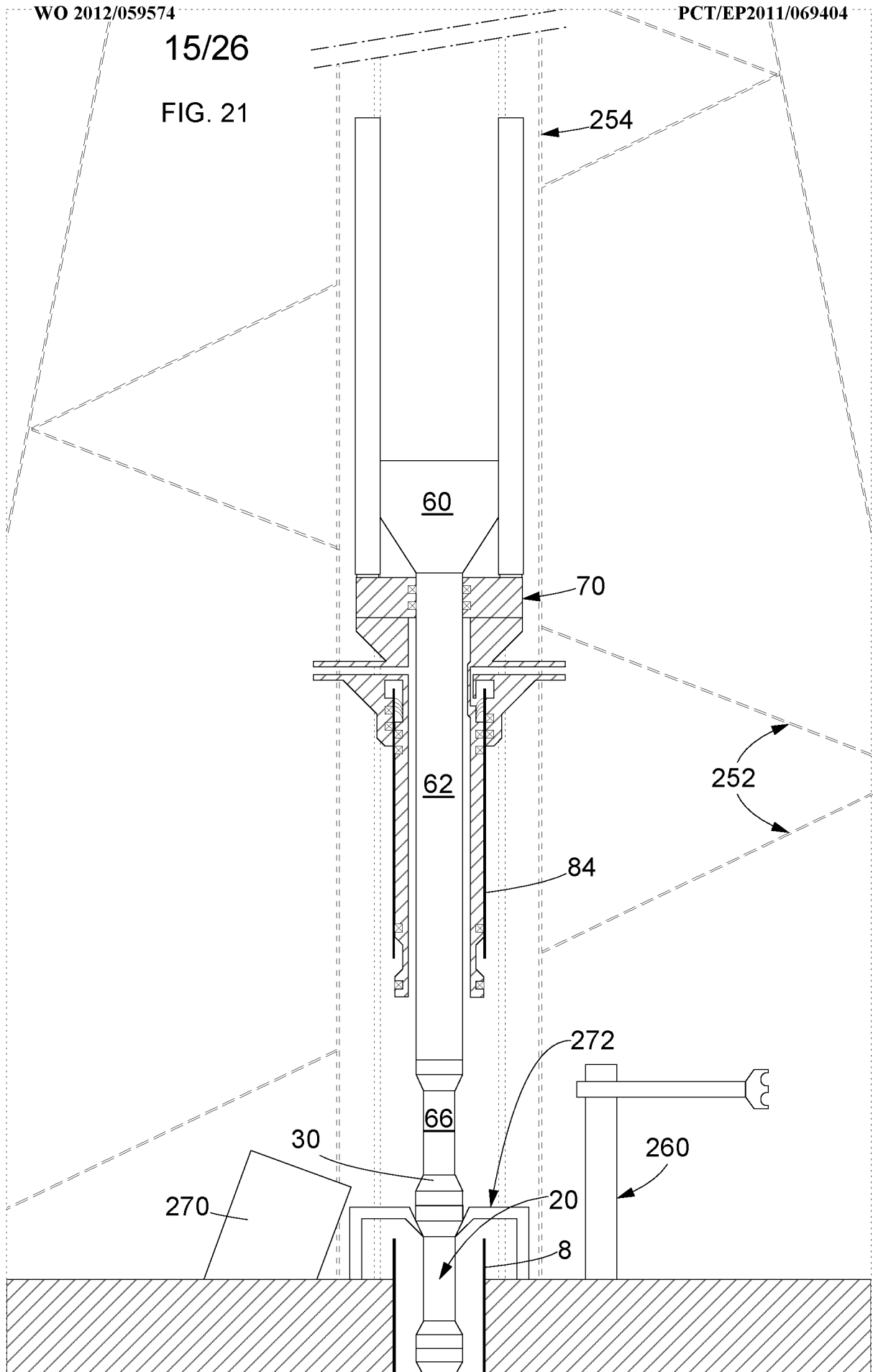
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FIG. 20



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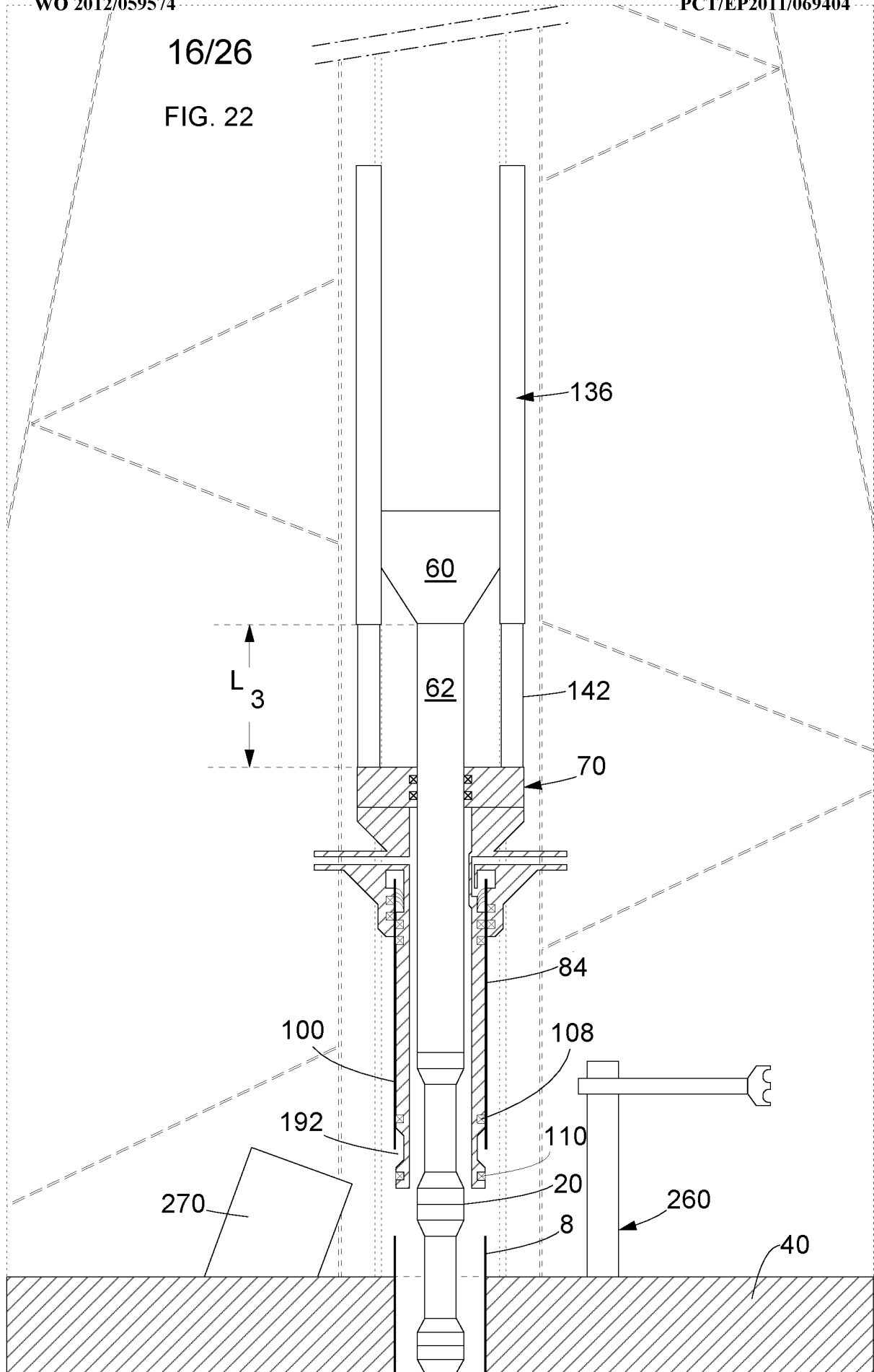
FIG. 21





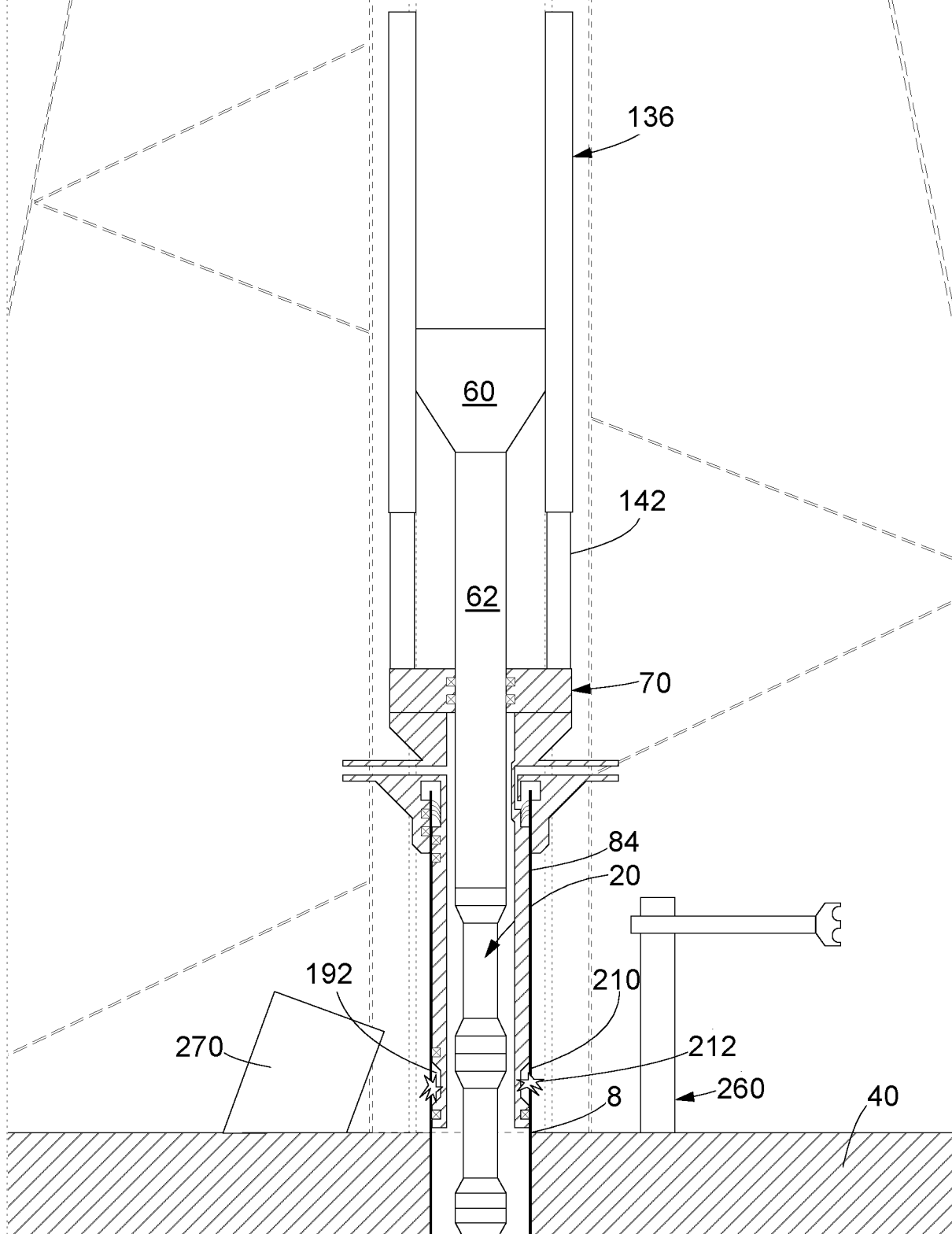
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FIG. 22



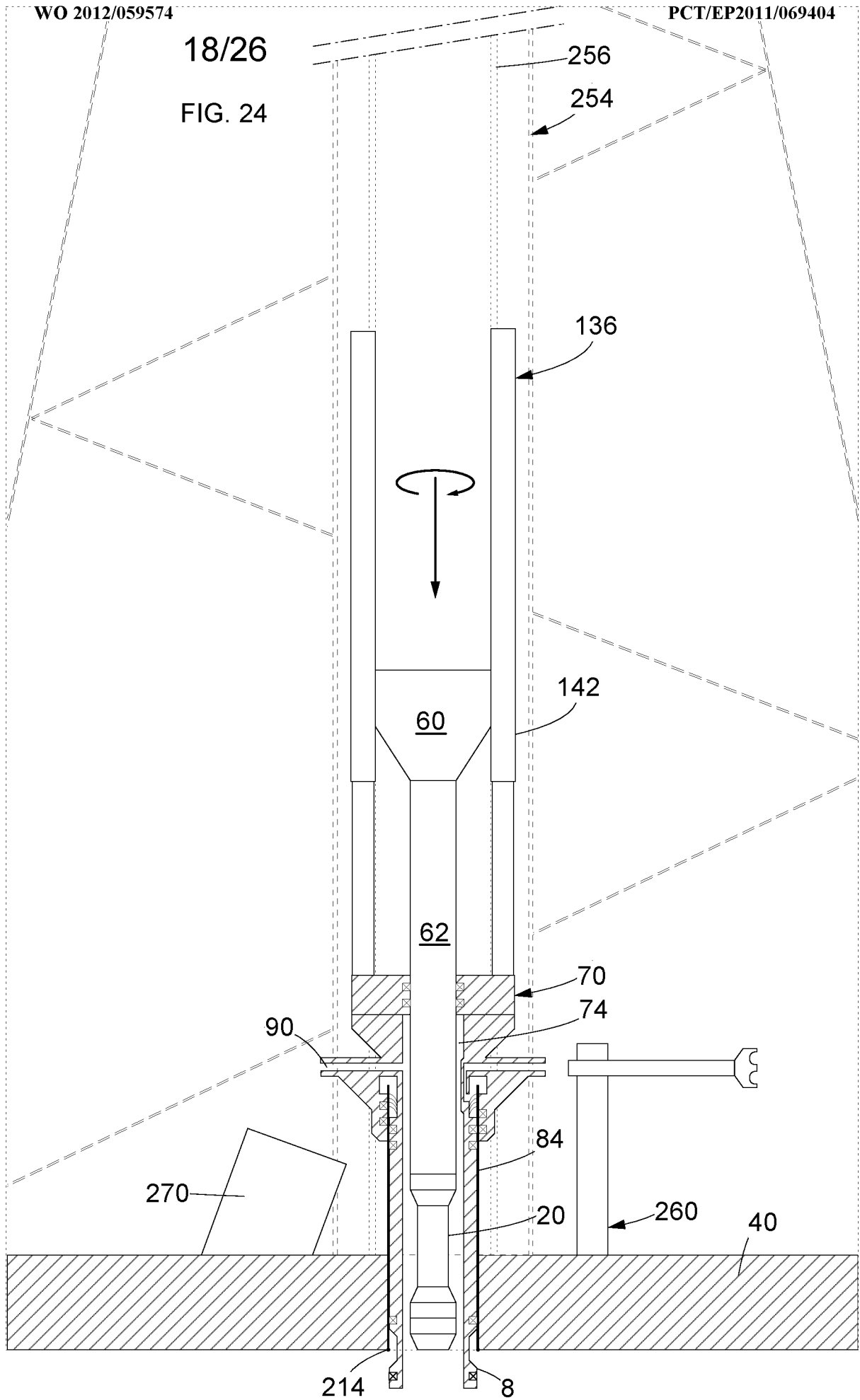
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FIG. 23



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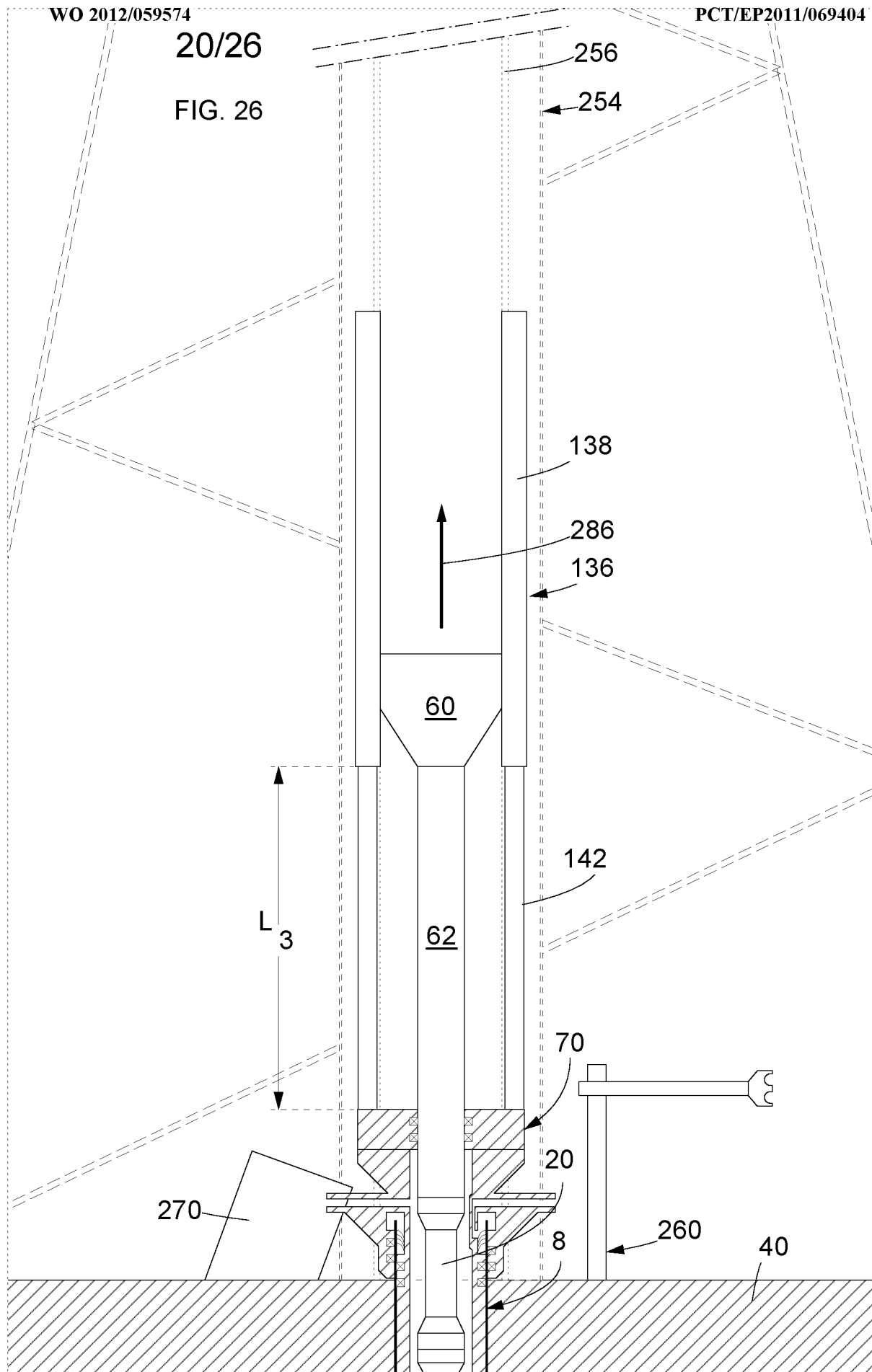
FIG. 24





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FIG. 26



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FIG. 27

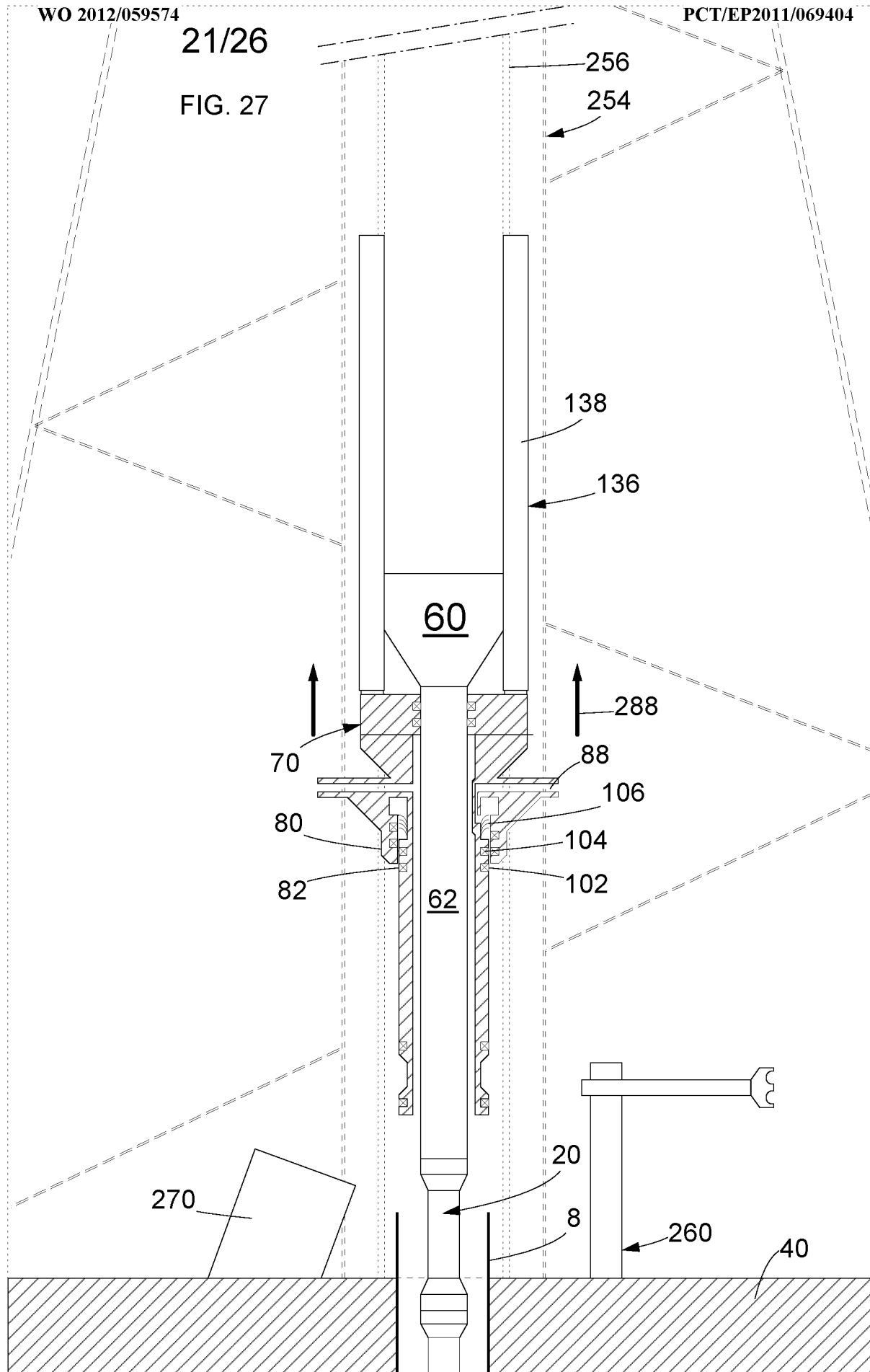
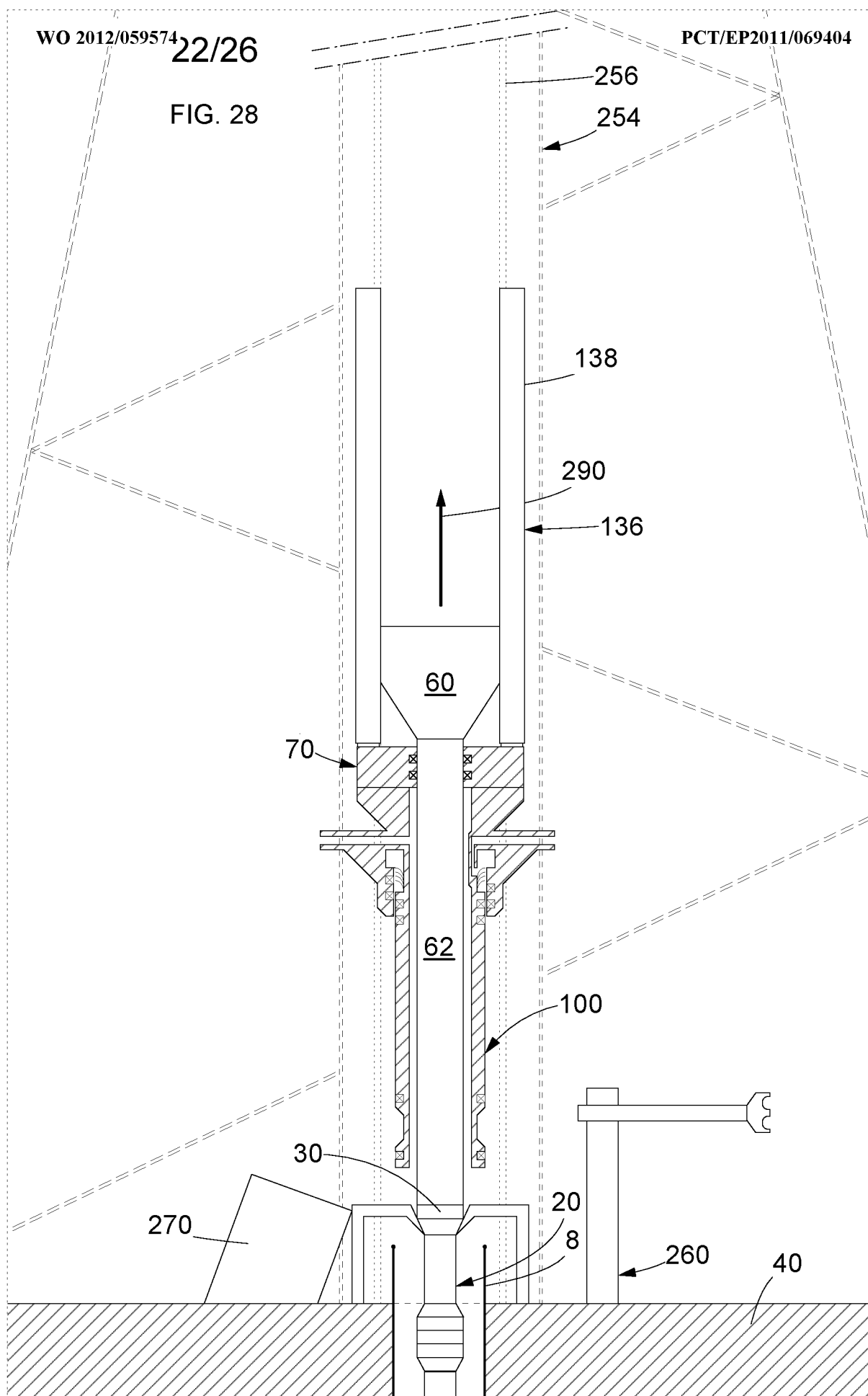
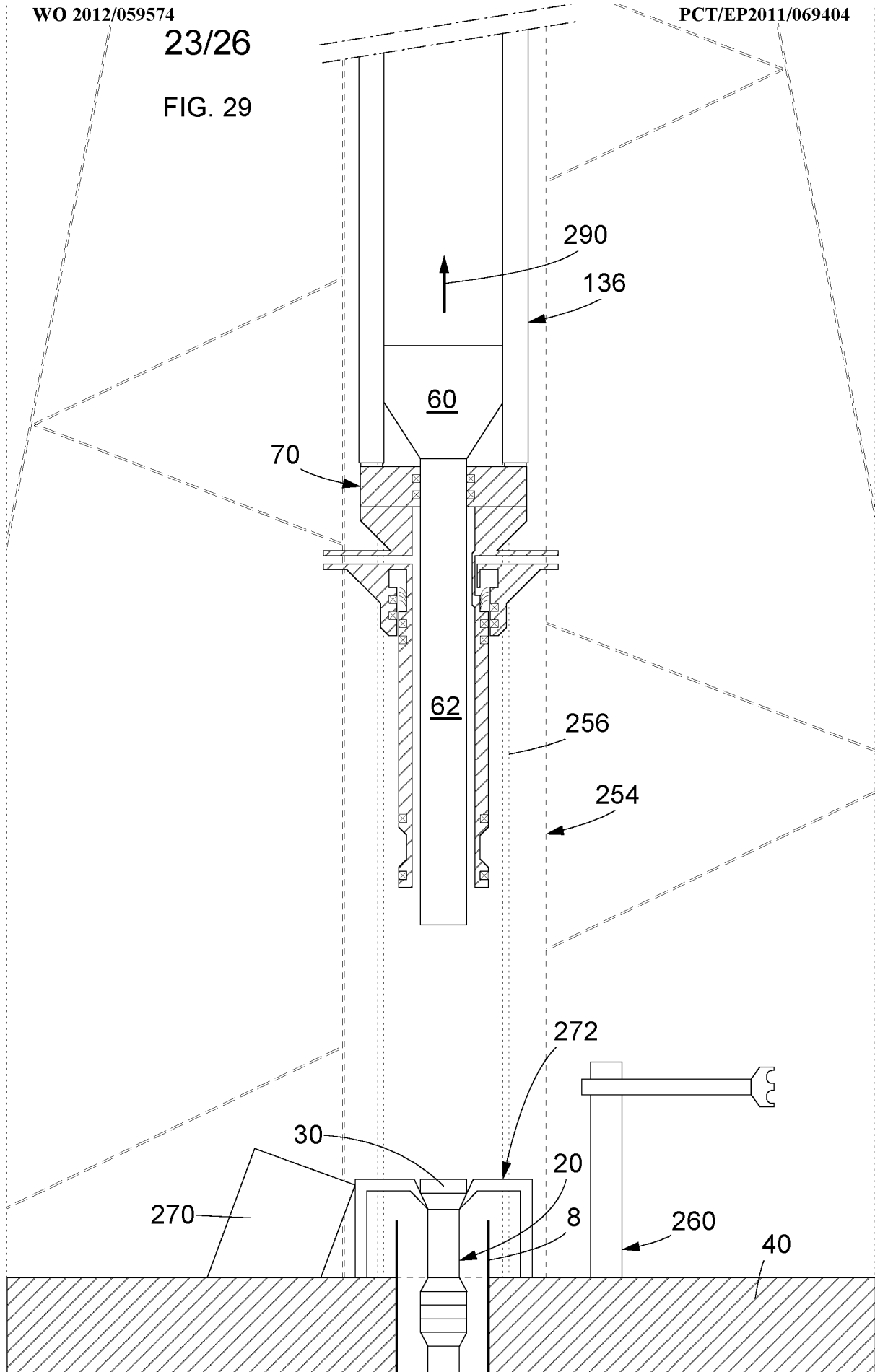


FIG. 28



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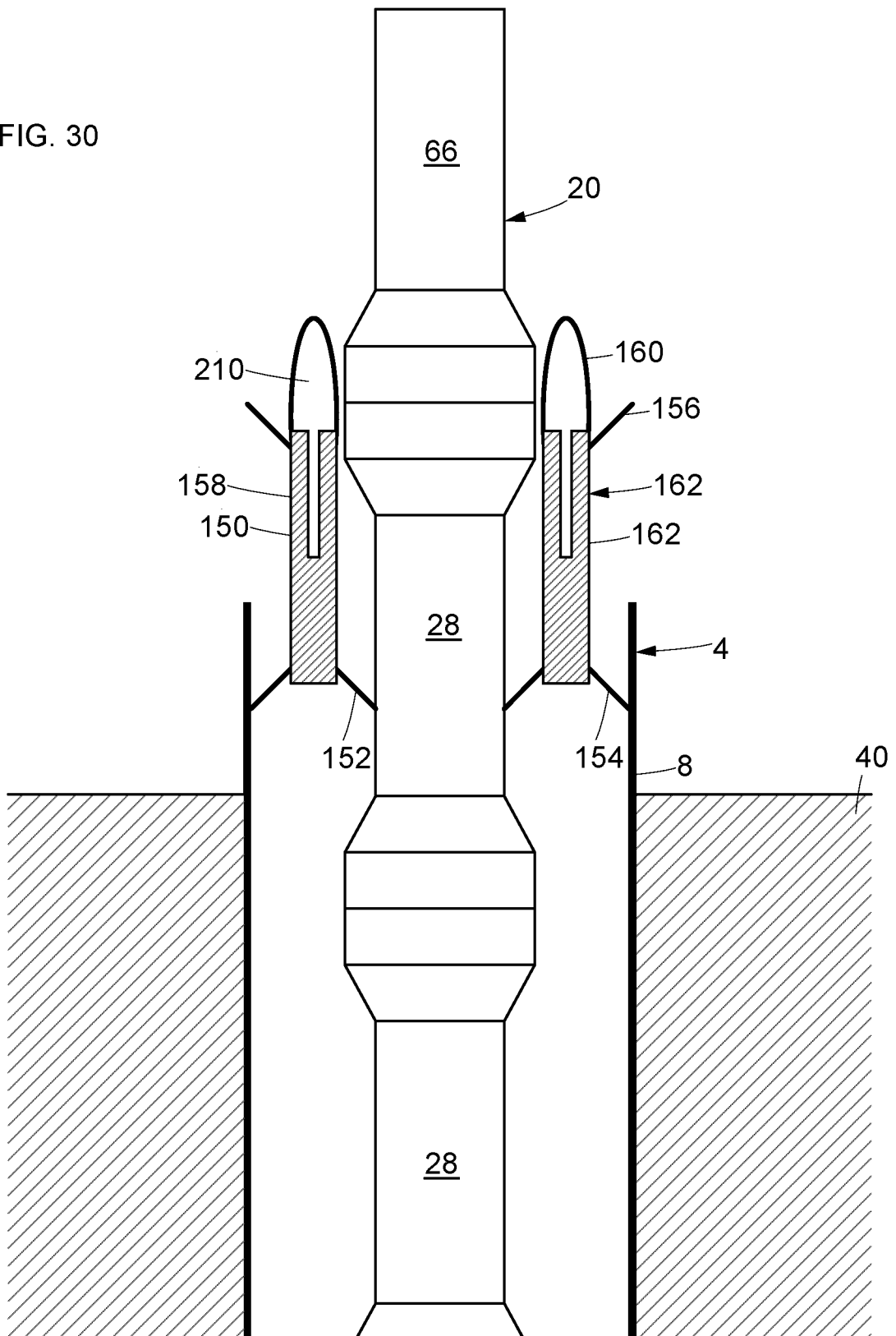
FIG. 29





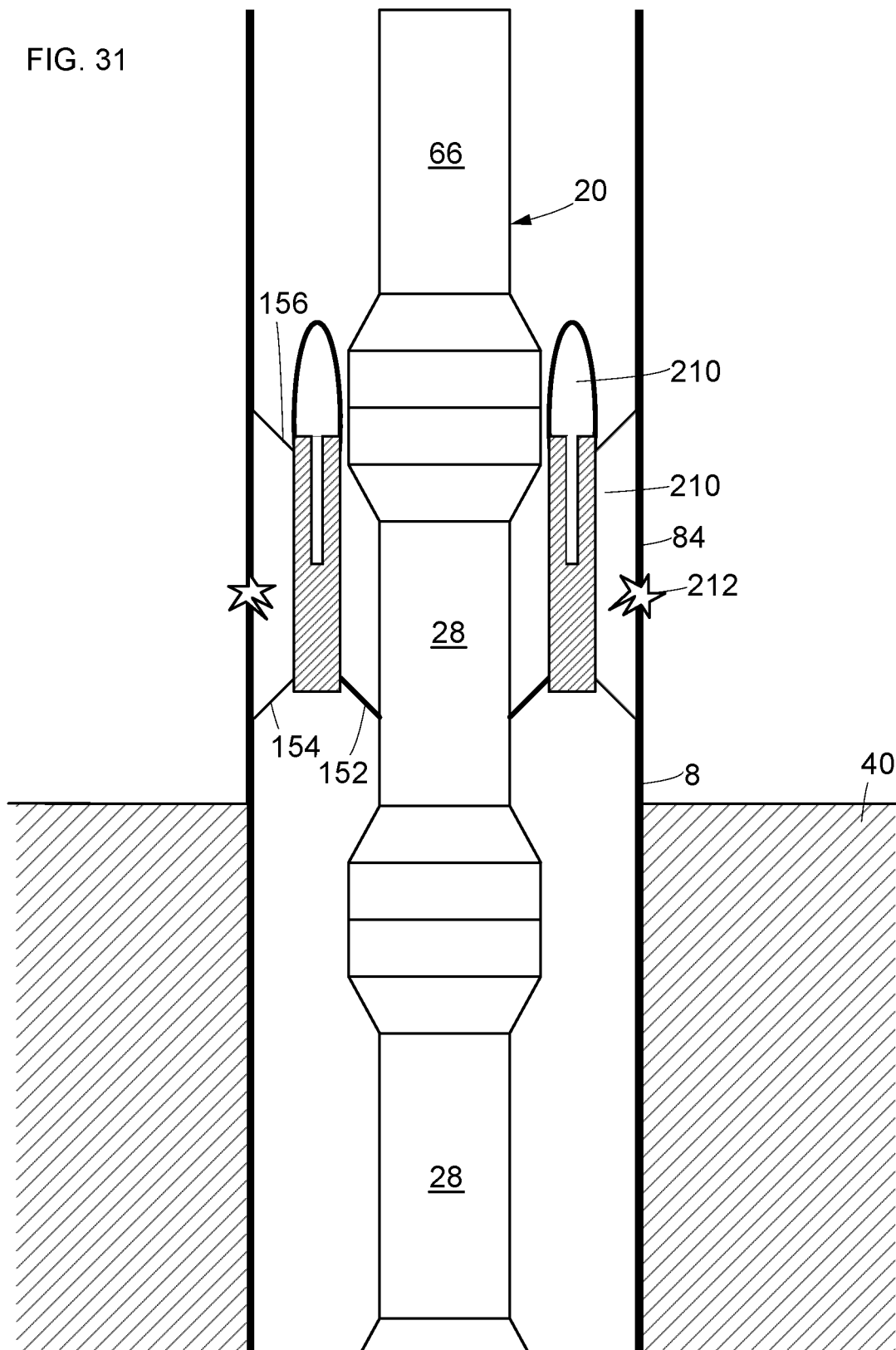
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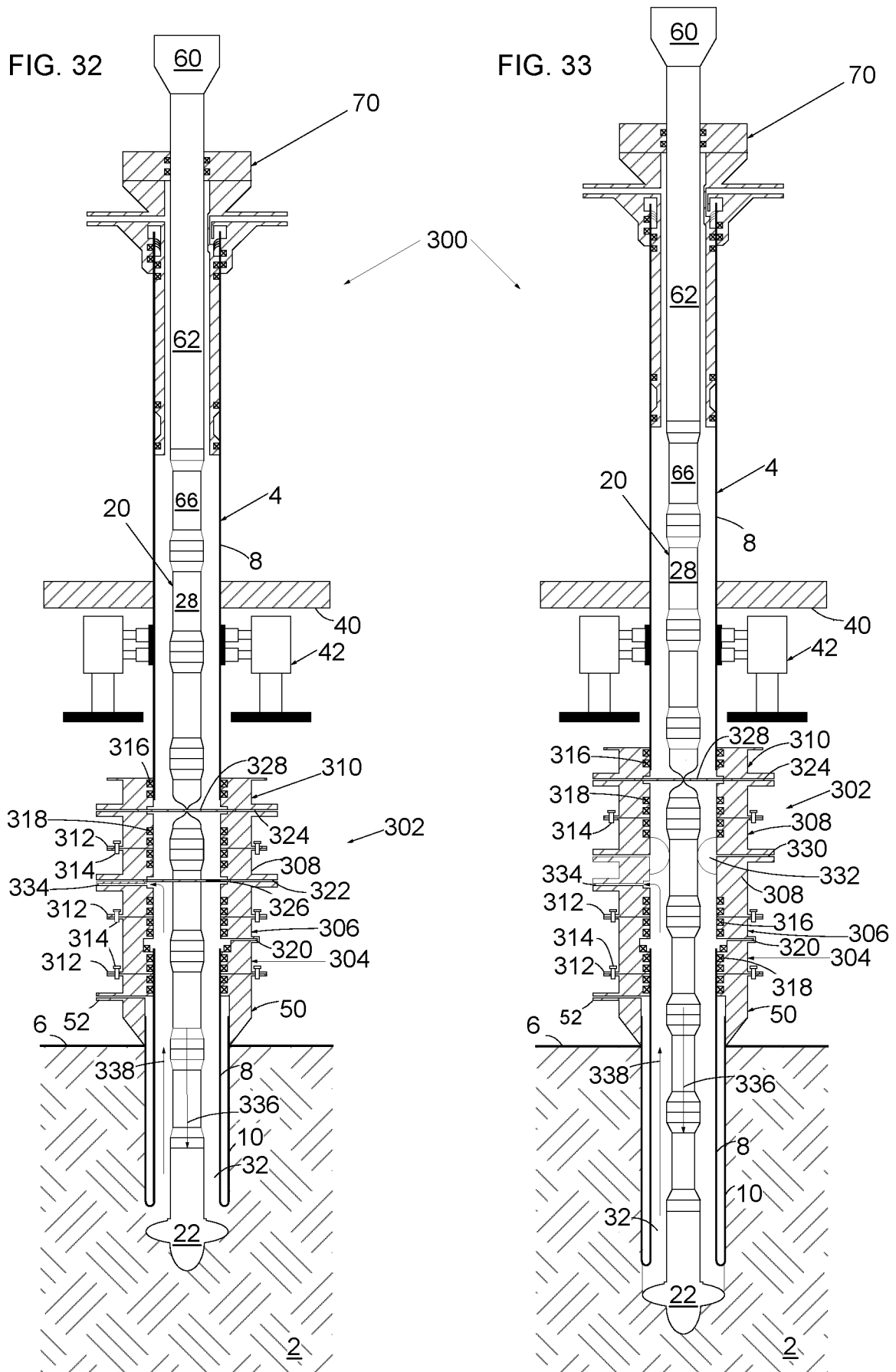
FIG. 30



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FIG. 31





# INTERNATIONAL SEARCH REPORT

International application No  
PCT/EP2011/069404

<b>A. CLASSIFICATION OF SUBJECT MATTER</b> INV. E21B7/20 E21B33/068 E21B43/10 F16L55/165 ADD.		
According to International Patent Classification (IPC) or to both national classification and IPC		
<b>B. FIELDS SEARCHED</b> Minimum documentation searched (classification system followed by classification symbols) E21B F16L		
Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched		
Electronic data base consulted during the international search (name of data base and, where practical, search terms used) EPO-Internal		
<b>C. DOCUMENTS CONSIDERED TO BE RELEVANT</b>		
Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	WO 2009/074632 A2 (SHELL INT RESEARCH [NL]; KRIESEL PETRUS CORNELIS [NL]) 18 June 2009 (2009-06-18) page 8, line 23 - page 9, line 6 figures 1-6	1-15
Y	WO 2009/065844 A1 (SHELL INT RESEARCH [NL]; KRIESEL PETRUS CORNELIS [NL]) 28 May 2009 (2009-05-28) page 8, lines 12-30 figure 1	1
Y	US 2007/137866 A1 (RAVENSBERGEN JOHN E [CA] ET AL RAVENSBERGEN JOHN EDWARD [CA] ET AL) 21 June 2007 (2007-06-21) paragraphs [0023] - [0026] figures 1-10	1
----- -/-		
<div style="display: flex; justify-content: space-between;"> <span><input checked="" type="checkbox"/> Further documents are listed in the continuation of Box C.</span> <span><input checked="" type="checkbox"/> See patent family annex.</span> </div>		
* Special categories of cited documents : <div style="display: flex; justify-content: space-between;"> <div style="width: 45%;"> <p>"A" document defining the general state of the art which is not considered to be of particular relevance</p> <p>"E" earlier document but published on or after the international filing date</p> <p>"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)</p> <p>"O" document referring to an oral disclosure, use, exhibition or other means</p> <p>"P" document published prior to the international filing date but later than the priority date claimed</p> </div> <div style="width: 45%;"> <p>"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention</p> <p>"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone</p> <p>"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.</p> <p>"&amp;" document member of the same patent family</p> </div> </div>		
Date of the actual completion of the international search  <div style="text-align: center; font-size: 1.2em;">30 November 2011</div>		Date of mailing of the international search report  <div style="text-align: center; font-size: 1.2em;">09/12/2011</div>
Name and mailing address of the ISA/ European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Fax: (+31-70) 340-3016		Authorized officer  <div style="text-align: center; font-size: 1.2em;">Manolache, Iustin</div>

## INTERNATIONAL SEARCH REPORT

International application No

PCT/EP2011/069404

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 4 431 069 A (DICKINSON III BEN W O [US] ET AL) 14 February 1984 (1984-02-14) the whole document -----	1-15

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International application No

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