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(54) Title: PERFORATION SYSTEM FOR RISERLESS ABANDONMENT OPERATION

(57) Abstract: A method for triggering a tool disposed in a wellbore includes: running the tool into the wellbore; running a heater into the wellbore and into a bore of the downhole tool; and while in the bore, operating the heater to heat a portion of the downhole tool to a threshold temperature. A control circuit of the downhole tool detects the threshold temperature and operates an actuator of the downhole tool in response to the detection.

PERFORATION SYSTEM FOR RISERLESS ABANDONMENT OPERATION

BACKGROUND OF THE DISCLOSURE

Field of the Disclosure

[0001] The present disclosure generally relates to a perforation system for a riserless abandonment operation.

Description of the Related Art

[0002] Figures 1A-1C illustrate a prior art completed subsea well. A conductor string 3 may be driven into a floor 1f of the sea 1. The conductor string 3 may include a housing 3h and joints of conductor pipe 3p connected together, such as by threaded connections. Once the conductor string 3 has been set, a subsea wellbore 2 may be drilled into the seafloor 1f and extend into one or more upper formations 9u. A surface casing string 4 may be deployed into the wellbore 3. The surface casing string 4 may include a wellhead housing 4h and joints of casing 4c connected together, such as by threaded connections. The wellhead housing 4h may land in the conductor housing 3h during deployment of the surface casing string 4. The surface casing string 4 may be cemented 8s into the wellbore 2. Once the surface casing string 2 has been set, the wellbore 2 may be extended and an intermediate casing string 5 may be deployed into the wellbore. The intermediate casing string 5 may include a hanger 5h and joints of casing 5c connected together, such as by threaded connections. The intermediate casing string 5 may be cemented 8i into the wellbore 2.

[0003] Once the intermediate casing string 5 has been set, the wellbore 2 may be extended into and a hydrocarbon-bearing (i.e., crude oil and/or natural gas) reservoir 9r. The production casing string 6 may be deployed into the wellbore. The production casing string 6 may include a hanger 6h and joints of casing 6c connected together, such as by threaded connections. The production casing string 6 may be cemented 8p into the wellbore 2. Each casing hanger 5h, 6h may be sealed in the wellhead housing 4h by a packoff. The housings 3h, 4h and hangers 5h, 6h may be collectively referred to as a wellhead 10.

[0004] A production tree 15 may be connected to the wellhead 10, such as by a tree connector 13. The tree connector 13 may include a fastener, such as dogs, for fastening the tree to an external profile of the wellhead 10. The tree connector 13 may further include a hydraulic actuator and an interface, such as a hot stab, so that a remotely operated subsea vehicle (ROV) 20 (Figure 2A) may operate the actuator for engaging the dogs with the external profile. The tree 15 may be vertical or horizontal. If the tree is vertical (not shown), it may be installed after a production tubing string 7 is hung from the wellhead 10. If the tree 15 is horizontal (as shown), the tree may be installed and then the production tubing string 7 may be hung from the tree 15. The tree 15 may include fittings and valves to control production from the wellbore 2 into a pipeline (not shown) which may lead to a production facility (not shown), such as a production vessel or platform.

[0005] The production tubing string 7 may include a hanger 7h and joints of production tubing 7t connected together, such as by threaded connections. The production tubing string 7 may further include a subsurface safety valve (SSV) 7v interconnected with the tubing joints 7t and a hydraulic conduit 7c extending from the valve 7v to the hanger 7h. The production tubing string 7 may further include a production packer 7p and the packer may be set between a lower end of the production tubing and the production casing string 6 to isolate an annulus 7a (aka the A annulus) formed therebetween from production fluid (not shown). The tree 15 may also be in fluid communication with the hydraulic conduit 7c. A lower end of the production casing string 6 may be perforated 11 to provide fluid communication between the reservoir 9r and a bore of the production tubing string 7. The production tubing string 7 may transport production fluid from the reservoir 9r to the production tree 15.

[0006] The tree 15 may include a head 12, the tubing hanger 7h, the tree connector 13, an internal cap 14, an external cap 16, an upper crown plug 17u, a lower crown plug 17b, a production valve 18p, one or more annulus valves 18u,b, and a face seal 19. The tree head 12, tubing hanger 7h, and internal cap 14 may each have a longitudinal bore extending therethrough. The tubing hanger 7h and head 12 may each have a lateral production passage formed through walls thereof for the flow of production fluid. The tubing hanger 7h may be disposed in the head bore. The tubing hanger 7h may be fastened to the head by a latch.

[0007] Once the reservoir 9r has been produced to depletion, the well must be abandoned. Conventionally, an abandonment operation includes cutting into the casings and filling the annuli with cement to seal the upper regions of the annuli. To achieve this, it is usual to use a semi-submersible drilling vessel (SSDV) which is located above the well and anchored in position. After removal of the cap 16 from the well, a unit including blow-out preventers and a riser is lowered and locked on to the wellhead. A tool string is run on pipe to sever or perforate the casing or casings. Weighted fluid is pumped into the well to provide a hydrostatic head to balance any possible pressure release when the casing is cut. The casing is then cut, and the annulus cemented. The cemented annulus is then pressure tested to ensure an adequate seal has been obtained. The casing is severed below the mud line and the casing hangers retrieved, and finally after removal from the well, the well is filled with cement. Whilst by this procedure satisfactory well abandonment can be achieved, it is expensive in terms of the equipment involved and the time taken which is often from seven to ten days per well.

SUMMARY OF THE DISCLOSURE

[0008] The present disclosure generally relates to a perforation system for a riserless abandonment operation. In one embodiment, a method for triggering a tool disposed in a wellbore includes: running the tool into the wellbore; running a heater into the wellbore and into a bore of the downhole tool; and while in the bore, operating the heater to heat a portion of the downhole tool to a threshold temperature. A control circuit of the downhole tool detects the threshold temperature and operates an actuator of the downhole tool in response to the detection.

[0009] In another embodiment, a perforating gun includes: a tubular mandrel having a solid wall and a bore therethrough; a thermometer in thermal communication with the wall; a control circuit in communication with the thermometer; a battery in communication with the control circuit; an electric match in communication with the control circuit; detonation cord in communication with the electric match; and one or more shaped charges connected to the detonation cord.

BRIEF DESCRIPTION OF THE DRAWINGS

[0010] So that the manner in which the above recited features of the present disclosure can be understood in detail, a more particular description of the disclosure, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this disclosure and are therefore not to be considered limiting of its scope, for the disclosure may admit to other equally effective embodiments.

[0011] Figures 1A-1C illustrate a prior art completed subsea well.

[0012] Figures 2A-2C illustrate deployment of a lower bridge plug to commence abandonment of an upper portion of the well after abandonment of a lower portion of the well, according to one embodiment of the present disclosure. Figure 2D illustrates setting the lower bride plug in the production casing string of the well.

[0013] Figures 3A-3C illustrate a lower annulus cementing tool of the annulus cementing system. Figure 3D illustrates deployment of the lower annulus cementing tool. Figure 3E illustrates setting of the lower annulus cementing tool in the production casing.

[0014] Figure 4A illustrates a pressure control assembly (PCA) of the annulus cementing system. Figure 4B illustrates deployment of the PCA. Figure 4C illustrates installation of the PCA onto the subsea wellhead and connection of the PCA to the support vessel.

[0015] Figures 5A and 5B illustrate an upper annulus cementing tool of the annulus cementing system. Figure 5C illustrates deployment of the upper annulus cementing tool. Figure 5D illustrates hanging of the upper annulus cementing tool from the PCA. Figure 5E illustrates stabbing of the upper annulus cementing tool into the lower annulus cementing tool. Figure 5F illustrates deployment of a tool housing to the PCA.

[0016] Figure 6A illustrates a perforation assembly of the annulus cementing system. Figures 6B-6G illustrate cement plugging of an annulus formed between the production casing and the intermediate casing strings. Figure 6B illustrates deployment of the perforation assembly. Figure 6C illustrates firing of a lower perforating gun to perforate the production casing. Figure 6D illustrates operation of the perforation assembly to activate a perforating gun of the upper annulus cementing tool. Figure 6E illustrates firing of the perforating gun to again perforate the production casing. Figure 6F illustrates pumping cement slurry into the annulus. Figure 6G illustrates launching of a cementing plug of the lower annulus cementing tool.

[0017] Figures 7A-7G illustrate cement plugging of an annulus formed between the intermediate and the surface casing strings. Figure 7A illustrates deployment of a second perforation assembly. Figure 7B illustrates firing of a second lower perforating gun to perforate the production and intermediate casing strings. Figure 7C illustrates operation of the second perforation assembly to activate a second perforating gun of the upper annulus cementing tool. Figure 7D illustrates firing of the second perforating gun to again perforate the production and intermediate casing strings. Figure 7E illustrates pumping cement slurry into the annulus. Figure 7F illustrates deployment of a bore plug. Figure 7G illustrates setting the bore plug in the lower annulus cementing tool.

[0018] Figures 8A-8C illustrate abandonment of the subsea wellhead. Figure 8A illustrates deployment of an upper bridge plug. Figure 8B illustrates setting the upper bride plug in the production casing. Figure 8C illustrates cement plugging a bore of the production casing.

[0019] Figure 9 illustrates an alternative perforation assembly for the annulus cementing system, according to another embodiment of the present disclosure.

DETAILED DESCRIPTION

[0020] Figures 2A-2C illustrate deployment of a lower bridge plug 33b to commence abandonment of an upper portion of the well after abandonment of a lower portion of the well, according to one embodiment of the present disclosure. Figure 2D illustrates setting the lower bride plug 33b in the production casing string 6 of the well.

[0021] To abandon the lower portion of the well, a support vessel 21 may be deployed to a location of the subsea tree 15. The support vessel 21 may be a light or medium intervention vessel and include a dynamic positioning system to maintain position of the vessel 21 on the waterline 1w over the tree 15 and a heave compensator (not shown) to account for vessel heave due to wave action of the sea 1. The vessel 21 may further include a tower 22 located over a moonpool 23 and a winch 24. The winch 24 may include a drum having wire rope 25 (Figure 4B) wrapped therearound and a motor for winding and unwinding the wire rope, thereby raising and lowering a distal end of the wire rope relative to the tower 22. The vessel 21 may further include a wireline winch 26.

[0022] Alternatively, the vessel 21 may be a mobile offshore drilling unit (MODU). Alternatively, a crane (not shown) may be used instead of the winch and tower.

[0023] The ROV 20 may be deployed into the sea 1 from the vessel 21. The ROV 20 may be an unmanned, self-propelled submarine that includes a video camera, an articulating arm, a thruster, and other instruments for performing a variety of tasks. The ROV 20 may further include a chassis made from a light metal or alloy, such as aluminum, and a float made from a buoyant material, such as syntactic foam, located at a top of the chassis. The ROV 20 may be connected to support vessel 21 by an umbilical 27. The umbilical 27 may provide electrical (power), hydraulic, and data communication between the ROV 20 and the support vessel 21. An operator on the support vessel 21 may control the movement and operations of ROV 20. The ROV umbilical 27 may be wound or unwound from drum 28.

[0024] The ROV 20 may be deployed to the tree 15. The ROV 20 may transmit video to the ROV operator for inspection of the tree 15. The ROV 20 may remove the external cap 16 from the tree 15 and carry the cap to the vessel 21. The ROV 20 may then inspect an internal profile of the tree 15. The wire rope 25 may then be used to lower a pressure control head (not shown) to the tree 15 through the moonpool 23 of the vessel 21. The ROV 20 may guide landing of the pressure control head onto the tree 15.

[0025] Alternatively, the winch 24 may be used to transport the external cap 16 to the waterline 1w.

[0026] A seal head (not shown) may then be deployed through the moonpool 23 using the wireline winch 26 and landed on the pressure control head. A plug retrieval tool (PRT) (not shown) may be released from the seal head and electrical power supplied to the PRT via wireline 29, thereby operating the PRT to remove the crown plugs 17u,b. A tree saver (not shown) may or may not then be installed in the production tree 15 using a modified PRT. Once the crown plugs 17u,b have been removed from the tree 15, a bottomhole assembly (BHA) (not shown) may be connected to the wireline 29 and the seal head deployed to the pressure control head. The BHA may include a cablehead, a collar locator, and a perforator, such as a perforating gun.

[0027] Once the seal head has landed on the pressure control head, the SSV 7v may be opened and the BHA may be deployed into the wellbore 2 using the wireline 29. The BHA may be deployed to a depth adjacent to and above the production packer 7p. Once the BHA has been deployed to the setting depth, electrical power may then be supplied to the BHA via the wireline 29 to fire the perforating gun into the production tubing 7t, thereby forming lower perforations 30b through a wall thereof. The BHA may be retrieved to the seal head and the seal head dispatched from the pressure control head to the vessel 21. The lower annulus valve 18b may then be opened.

[0028] Cement slurry (not shown) may then be pumped from the vessel 21, through the pressure control head, down the production tree 15 and production tubing 7t, and into the tubing annulus 7a via the lower perforations 30b. Wellbore fluid displaced by the cement slurry may flow up the tubing annulus 7a, through the wellhead 10, tree annulus port, and to the vessel 21. Once a desired quantity of cement slurry has been pumped into the tubing annulus 7a, the lower annulus valve 18b may be closed while continuing to pump the cement slurry, thereby squeezing cement slurry into the formation. Once pumped, the cement slurry may be allowed to cure for a predetermined amount of time, such as one hour, six hours, twelve hours, or one day, thereby forming a lower cement plug 31b.

[0029] Once the lower cement plug 31b has cured, a second BHA (not shown) may be connected to the wireline 29 and the seal head and deployed to the pressure control head. The second BHA may include a cablehead, a collar locator, a setting tool, and a lower bridge plug 32b. The second BHA may be deployed to a depth adjacent to and above the lower cement plug 31b. Once the second BHA has been deployed to the setting depth, electrical power may then be supplied to the second BHA via the wireline 29 to operate the setting tool, thereby expanding the lower bridge plug 32b against an inner surface of the production tubing 7t. Once the lower bridge plug 32b has been set, the plug may be released from the setting tool. The setting tool may then be retrieved to the seal head and the seal head and setting tool dispatched from the pressure control head to the vessel 21.

[0030] The BHA may then be redeployed to the pressure control head and into the wellbore 2 using the wireline 29. The BHA may be redeployed to a depth below a shoe of the intermediate casing string 5 and above a top of the production casing cement 8p. Once the BHA has been deployed to the setting depth, electrical power may then be supplied to the BHA via the wireline 29 to fire the perforating guns into the production tubing 7t, thereby forming upper perforations 30u through a wall thereof. The BHA may be retrieved to the seal head and the seal head and BHA dispatched from the pressure control head to the vessel 21.

[0031] Cement slurry (not shown) may then be pumped from the vessel 21, through pressure control head, down the production tree 15 and production tubing 7t, and into the tubing annulus 7a via the upper perforations 30u. Wellbore fluid displaced by the cement slurry may flow up the tubing annulus 7a, through the wellhead 10, tree annulus port, and to the vessel 21. Once a desired quantity of cement slurry has been pumped, the cement slurry may be allowed to cure, thereby forming an upper cement plug 31u.

[0032] Once the upper cement plug 31u has cured, the second BHA may be reconnected to the wireline 29 and seal head and redeployed to the pressure control head. The second BHA may be redeployed to a depth adjacent to and above the upper cement plug 31u. Once the second BHA has been deployed to the setting depth, the upper bridge plug 32u may be set against the inner surface of the production tubing 7t. Once the upper bridge plug 32u has been set, the plug may be released from the setting tool and the second BHA may then be retrieved to the seal head and the seal head dispatched from the pressure control head to the vessel 21.

[0033] A third BHA (not shown) may then be connected to the wireline 29 and seal head and deployed to the pressure control head. The third BHA may include a cablehead, a collar locator, an anchor, a hydraulic power unit (HPU), an electric motor, and a tubing cutter. The third BHA may be deployed into the production tubing string 7 to a depth adjacent to and above the upper bridge plug 32u. Once the third BHA has been deployed to the cutting depth, the HPU may be operated by supplying electrical power via the wireline 29 to extend blades of the tubing cutter and the motor operated to rotate the extended blades, thereby severing an upper portion of the production tubing string 7 from a lower portion thereof.

[0034] Alternatively, the tubing cutter may be a thermite torch.

[0035] The third BHA may then be retrieved to the seal head and the seal head and third BHA dispatched from the pressure control head to the vessel 21. Once the third BHA and seal head have been retrieved to the vessel 21, the pressure control head may be disconnected from the tree 15 and retrieved to the vessel. A tree grapple (not shown) may be connected to the wire rope 25 and lowered from the vessel 21 into the sea 1 via the moon pool 23. The ROV 20 may guide landing of the tree grapple onto the tree 15. The ROV 20 may then operate a connector of the tree grapple to fasten the grapple to the tree 15. The ROV 20 may then disengage the tree connector 13 from the wellhead 10 and the production tree 15 and the severed upper portion of the production tubing string 7 may be lifted to the vessel 21 by operating the winch 24.

[0036] Once the production tree 15 has been retrieved to the vessel 21, a fourth BHA 34 may be connected to the wireline 29 and deployed through the open sea 1 to the subsea wellhead 10. The fourth BHA 34 may include a cablehead, a collar locator, a setting tool, and the lower bridge plug 33b. The setting tool may include a mandrel and a piston longitudinally movable relative to the mandrel. The setting mandrel may be connected to the collar locator and fastened to a mandrel of the lower bridge plug 33b, such as by a shearable fastener. The setting tool may include a firing head and a power charge. The firing head may receive electrical power from the wireline 29 to operate an electric match thereof and fire the power charge. Combustion of the power charge may create high pressure gas which exerts a force on the setting piston. The lower bridge plug 33b may include a mandrel, an anchor, and a packing element. The mandrel and anchor may be made from a metal or alloy, such as cast iron, and the packing element may be made from an elastomer or elastomeric copolymer. The anchor and packing element may be disposed along an outer surface of the plug mandrel between a setting shoulder of the mandrel and a setting ring. The setting piston may engage the setting ring and drive the packing and anchor against the setting shoulder, thereby setting the lower bridge plug 33b.

[0037] The fourth BHA 34 may be lowered through the subsea wellhead 10 into the production casing 6c and deployed to a depth therein adjacent to and above the upper bridge plug 32u. Once the fourth BHA 34 has been deployed to the setting depth, electrical power may then be supplied to the BHA via the wireline 29 to operate the setting tool, thereby expanding the lower bridge plug 33b against an inner surface of the production casing 6c. Once the lower bridge plug 33b has been set, the plug may be released from the setting tool by exerting tension on the wireline 29 to fracture the shearable fastener. The fourth BHA 34 (minus the lower bridge plug 33b) may then be retrieved to the vessel 21.

[0038] Figures 3A-3C illustrate a lower annulus cementing tool 35 of the annulus cementing system. The lower annulus cementing tool 35 may include a polished bore receptacle (PBR) 36, a packer 37, a nipple 38, a bore plug 39, and a cementing plug 40. The PBR 36 may be tubular, have seal bore formed at an upper end thereof, and have a coupling, such as a thread, formed adjacent to a lower end thereof.

[0039] The packer 37 may include a mandrel 42, a setting unit 43, a packing unit 44 and an anchor unit 45. The anchor unit 45 may include a set of metallic grippers 46 radially movable between an extended position (Figure 3C) and a retracted position (Figure 3B) and having teeth formed on an outer surface thereof for engagement with an inner surface of the production casing 6c. A respective end of each gripper 46 may be fastened to respective upper 48u and lower 48b retainers via upper 47u and lower 47b pivotal links. The grippers 46 may be longitudinally connected to the pivotal links 47u,b, such as by fasteners. The pivotal links 47u,b may be longitudinally connected to the retainers 48u,b, such as by ball and socket joints. Each retainer 48u,b may be a ring assembly disposed around an outer surface of the mandrel 42 and longitudinally movable relative thereto.

[0040] To guide extension of the anchor unit 45, each pivotal link 47u,b may have a cam profile formed in a face thereof adjacent to the grippers 46 and the grippers may each have complementary cam profiles formed in upper and lower faces thereof. The anchor unit 45 may also be arranged such that a slight inclination angle exists in the retracted position. The inclination angle may be formed between a longitudinal axis of each pivotal link 47u,b and a transverse axis of the respective fastener connecting the link to the respective gripper 46 .

[0041] The packer 37 may further include an adapter 49 connected to a lower end of the mandrel 42, such as by threads secured with a fastener. The adapter 49 may be tubular and have a coupling, such as a threaded box (not shown) or pin (shown), formed at a lower end thereof. A top of the adapter 49 may serve as a stop shoulder for the anchor unit 45. The anchor unit 45 may further include upper 50u and lower 50b springs. Each spring 50u,b may be a compression spring, such as a Belleville spring. The lower spring 50b may have a lower end bearing against a top of the adapter 49 and an upper end bearing against a bottom of a lower spring washer 51b. A spring chamber may be formed radially between an outer surface of the mandrel 42 and an inner surface of a lower protector sleeve 52b. The lower protective sleeve 52b may be connected to the adapter 49, such as by threaded couplings, and be coupled to the lower spring washer 51b, such as by a splice joint. The splice joint may accommodate operation of the lower spring 50b. The lower spring washer 51b may be connected to the lower link retainer 48b, such as by threaded couplings.

[0042] An upper spring washer 51u may be connected to the upper link retainer 48u, such as by threaded couplings. An upper protective sleeve 52u may be coupled to the upper spring washer 51u, such as by a splice joint. The upper spring 50u may be disposed in a spring chamber formed between the upper protective sleeve 52u and the mandrel 42 and the splice joint may accommodate operation thereof. The upper spring 50u may have a lower end bearing against a top of the upper spring washer 51u.

[0043] The packing unit 44 may include a packing element 54 and a pair of glands 53u,b straddling the packing element. Each longitudinal end of the packing element 54 may be attached to the respective gland 53u,b. The packing element 54 may be made from an expandable material, such as an elastomer or elastomeric copolymer. The packing element 54 may be naturally biased toward a contracted position (Figure 3B) and compression of the packing element between the glands 53u,b may radially expand (Figure 3C) the packing element into engagement with an inner surface of the production casing 6c, thereby isolating a lower portion of a working annulus 67 (Figure 3E) formed between the lower cementing tool 37 and the production casing 6c from an upper portion thereof. The packing unit 44 may further include strands of fiber extending between the glands for reinforcing the packing element 54.

[0044] The packing unit 44 may further include upper 55u and lower 55b sets of backup rings located adjacent to the respective glands 53u,b. An end of each backup ring 55u,b adjacent to the respective gland 53u,b may be longitudinally connected to respective sliders 56u,b, such as ball and socket joints. A distal end of each backup ring 55u,b may be fastened to the respective upper 57u and lower 57b retainers via upper 58u and lower 58b pivotal links. The backup rings 55u,b may be longitudinally connected to the pivotal links 58u,b, such as by fasteners. The pivotal links 58u,b may be longitudinally connected to the retainers 57u,b, such as by ball and socket joints. Each retainer 57u,b may be a ring assembly disposed around an outer surface of the mandrel 42 and longitudinally movable relative thereto.

[0045] The upper spring 50u may have an upper end bearing against a bottom of the lower link retainer 57b. The upper protective sleeve 52u may be connected to the lower link retainer 57b, such as by threaded couplings. The packing unit 44 may further include a flexible shroud 59 covering the upper pivotal links 58u. The shroud 59 may have a bead formed in an inner surface thereof received in a groove formed in an outer surface of the upper link retainer 57u, thereby longitudinally connecting the two members. Each backup ring 55u,b may have a support face for receiving a respective end face of the packing element 54 in the expanded position and a pocket for receiving an end face of the respective gland 53u,b in the expanded position.

[0046] The setting unit 43 may include an outer sleeve 60, a cap 61, an inner sleeve 62, an anchor lock 63, and a packing lock 64. The cap 61 may be connected to an upper end of the outer sleeve 60, such as by threaded couplings. The outer sleeve 60 may also have a coupling, such as a thread, for receiving the threaded lower end of the PBR 36, thereby connecting the members. The mandrel 42 may have a latch profile formed in an inner surface thereof for engagement with a latch of a setting tool 65 (Figure 3E). A lower end of the outer sleeve 60 may be connected to the upper link retainer 57u, such as by threaded couplings.

[0047] The anchor lock 63 may include a body connected to an upper end of the inner sleeve 62, such as by threaded couplings, and releasably connected to the upper link retainer 57u, such as by a shearable fastener. The inner sleeve 62 may be disposed between the mandrel 42 and the packing unit 44 and extend along an outer surface of the mandrel such that an outer lug formed at a lower end of the inner sleeve is located adjacent to the lower link retainer 57b. The packing lock 64 may include a ratchet ring connected to the outer sleeve 60 and a ratchet profile formed in an outer surface of the mandrel 42.

[0048] The anchor lock 63 may further include a friction disk disposed along a plurality (only one shown) of threaded fasteners engaged with respective threaded sockets formed in a top of the body. The body top may be sloped and the fasteners may have different lengths to accommodate the slopes. Each fastener may carry a spring, such as a compression spring, bearing against an upper face of the friction disk and a head of the respective fastener. Each spring may have a different stiffness such that the friction disk is biased toward a cambered position, thereby locking the inner sleeve 62 to the mandrel 42. The friction disk may initially be held in a straight position by engagement with a top of the upper link retainer 57u, thereby allowing relative movement between the inner sleeve 62 and the mandrel 42.

[0049] The nipple 38 may be tubular, have a coupling, such as a threaded box (shown) or pin (not shown), formed at an upper end thereof and in engagement with the adapter coupling, thereby connecting the nipple and the packer 37. The nipple 38 may also may have a receiver profile formed in an inner surface thereof, and may have a coupling, such as a lap, formed in a lower end thereof. The bore plug 39 may include a body with a metallic seal on its lower end. The metallic seal may be a depending lip that engages the nipple receiver profile. The plug body may have a plurality of windows which allow fasteners, such as dogs, to extend and retract. The dogs may be pushed outward by an actuator, such as a central cam. The cam may have a retrieval profile formed in an inner surface thereof. The cam may move between a lower locked position and an upper position freeing the dogs to retract. A retainer, such as a nut, may connect to the upper end of the plug body to retain the cam. The extended dogs may engage the nipple receiver profile to fasten the bore plug 39 to the nipple 38.

[0050] The cementing plug 40 may be a wiper plug including a finned seal and a plug body. The finned seal may be made from an elastomer or elastomeric copolymer and attached to an outer surface of the plug body. The plug body may be tubular, may be made from a metal or alloy, may have an upper stem portion, and may have a seat formed in an inner surface thereof. The stem portion may be received by the nipple lap and one or more (pair shown) shearable fasteners 41 may be inserted into respective sockets formed through a wall of the nipple 38 and received by respective indentations formed in an outer surface of the stem portion, thereby releasably connecting the cementing plug 40 and the nipple.

[0051] Figure 3D illustrates deployment of the lower annulus cementing tool 35. Figure 3E illustrates setting of the lower annulus cementing tool 35 in the production casing 6c. Once the lower bridge plug 33b has been set in the production casing 6c, a fifth BHA 66 may be connected to the wireline 29 and deployed through the open sea 1 to the subsea wellhead 10. The fifth BHA 66 may include a cablehead, a collar locator, the setting tool 65, and the lower annulus cementing tool 35 minus the bore plug 39.

[0052] The setting tool 65 may be tubular and include a stroker, an HPU, a cablehead, an anchor, and a latch. The stroker, HPU, cablehead, and anchor, may each include a housing connected, such as by threaded connections. The stroker may include the housing and a shaft. The cablehead may include an electronics package (not shown) for controlling operation of the setting tool 65. The electronics package may include a programmable logic controller (PLC) having a transceiver in communication with the wireline 29 for transmitting and receiving data signals to the vessel 21. The electronics package may also include a power supply in communication with the PLC and the wireline 29 for powering the HPU, the PLC, and various control valves. The HPU may include an electric motor, a hydraulic pump, and a manifold. The manifold may be in fluid communication with the various setting tool components and include one or more control valves for controlling the fluid communication between the manifold and the components. Each control valve actuator may be in communication with the PLC. The cablehead may connect the setting tool 65 to the wireline 29. The anchor may include two or more radial piston and cylinder assemblies and a die connected to each piston or two or more slips operated by a slip piston.

[0053] A housing of the latch may be fastened to the stroker shaft, such as by a threaded connection. The latch may further include a fastener, such as a collet, connected to an end of the housing. The latch may further include a locking piston disposed in a chamber formed in the housing and operable between a locked position in engagement with the collet and an unlocked position disengaged from the collet. The locking piston may be biased toward the locked position by a spring, such as a compression spring. The locking piston may be in fluid communication with the HPU via a passage formed through the housing, a passage (not shown) formed through the shaft and via a hydraulic swivel (not shown) disposed between the stroker housing and shaft. The latch may further include a release piston disposed in a chamber formed in the housing and operable between an extended position in engagement with the latch profile of the packer mandrel 42 and a retracted position to allow disengagement of the collet. The release piston may be biased toward the retracted position by a spring member, such as a compression spring. The release piston may also be in fluid communication with the HPU via a passage formed through the housing, a second passage (not shown) formed through the shaft and via the hydraulic swivel.

[0054] Alternatively, flexible conduit and/or flexible cable may be used instead of the hydraulic swivel.

[0055] The fifth BHA 66 may be lowered though the subsea wellhead 10 and along the production casing 6c to a depth above the lower bridge plug 33b. Once the fifth BHA 66 has been deployed to the setting depth, electrical power may be supplied to the BHA via the wireline 29 to operate the setting tool 65, thereby setting the anchor thereof and operating the stroker to push the PBR 36, the setting unit 43, the packing unit 44, and an upper portion of the anchor unit 45 downward along the mandrel 42 which is held stationary by the engaged setting tool anchor. Once the grippers 46 have been extended against an inner surface of the production casing 6c, the shearable fastener of the setting unit 43 may fracture, thereby releasing the packing unit 44 from the anchor unit. The PBR 36, outer sleeve 60, and an upper portion of the packing unit 44 may continue to be pushed downward until the packing element 54 has expanded against the inner surface of the production casing 6c.

[0056] Once the packer 37 has been set, the lower annulus cementing tool 35 may be released from the setting tool 65 by operation of the release piston and retraction of the stroker. The setting tool anchor may then be released and the fifth BHA 66 (minus the lower annulus cementing tool 35) retrieved to the vessel 21.

[0057] Figure 4A illustrates a pressure control assembly (PCA) 70 of the annulus cementing system. The PCA 70 may include a wellhead connector 71, a wellhead adapter 72, a fluid sub 73, a BOP stack 74, a frame 75, a manifold 76, a termination receptacle 77, one or more (three shown) accumulators 78, a face seal 79 and a subsea control system.

[0058] The wellhead connector 71 may include a fastener, such as dogs, for fastening the PCA 70 to an external profile of the subsea wellhead 10. The wellhead connector 71 may further include an electric or hydraulic actuator and an interface, such as a hot stab, so that the ROV 20 may operate the actuator for engaging the dogs with the external profile. The frame 75 may be connected to the wellhead connector 71, such as by fasteners (not shown). The manifold 76 may be fastened to the frame 75.

[0059] The wellhead adapter 72, fluid sub 73, and BOP stack 74 may each include a body 72b, 73b having a longitudinal bore therethrough and be connected, such as by flanges, such that a continuous bore is maintained therethrough. The bore may be sized to accommodate an upper annulus cementing tool 90 (Figures 5A and 5B). The adapter body 72b may have couplings at each longitudinal end thereof. The upper coupling may be a flange for connection to the fluid sub 73 and the lower coupling may be threaded for connection to the wellhead connector 71. The adapter body 72b may also have a seal face formed in a bottom thereof for receiving the face seal 79, may have another seal face 72f formed in a side thereof, and a flow passage 72p formed in a wall thereof. The adapter body 72b may further include a landing profile 80 formed in an inner surface thereof for receiving a hanger 91 (Figure 5A) of the upper annulus cementing tool 90. The landing profile 80 may include a landing shoulder 80s, a latch profile, such as a groove 80g, and one or more seal bores, such as upper seal bore 80u and lower seal bore 80b.

[0060] The flow passage 72p may provide fluid communication between the seal face 72f and the subsea wellhead 10. A fluid conduit 81o may connect to the seal face 72f and the manifold 76 and provide fluid communication between the flow passage 79 and an outlet coupling 82o of an outlet dry break connection 83o (Figure 4C). The fluid sub 73 may include a port 73p formed through the body 73b thereof and communication with the bore. Another fluid conduit 81n may connect to the fluid sub 73 and the manifold 76 and provide fluid communication between the fluid sub port 73p and an inlet coupling 82n of an inlet dry break connection 83n (Figure 4C).

[0061] The BOP stack 74 may include one or more hydraulically operated ram preventers, such as a blind-shear preventer 74b and a wireline preventer 74w, connected together via bolted flanges. Each ram preventer 74b,w may include two opposed rams disposed within each body thereof. Opposed cavities may intersect the body bore and support the rams as they move radially into and out of the bore. A bonnet may be connected to the respective body on the outer end of each cavity and may support an actuator that provides the force required to move the rams into and out of the bore. Each actuator may include a hydraulic piston to radially move each ram and a mechanical lock to maintain the position of the ram in case of hydraulic pressure loss. The lock may include a threaded rod, a motor (not shown) for rotationally driving the rod, and a threaded sleeve. Once each ram is hydraulically extended into the bore, the motor may be operated to push the sleeve into engagement with the piston. Each actuator may include single or dual pistons. The blind-shear preventer 74b may cut the wireline 29 when actuated and seal the body bore. The wireline preventer 74w may seal against an outer surface of wireline 29 when actuated.

[0062] The termination receptacle 77 may be operable to receive a termination head 84h (Figure 4C) of a subsea control line 84u. The termination receptacle 77 may include a base 77b, a latch 77h, and an actuator 77a. The receptacle base 77b may be connected to the frame 75, such as by fasteners, and may include a landing plate for supporting the termination head 84h, a landing guide (not shown), such as a pin, and a stab plate. The receptacle stab plate and termination head 84h, when connected (termination assembly), may provide communication, such as electric (power and/or data), hydraulic, and/or optic, between the subsea control line 84u (Figure 4C) and the subsea control system. The subsea control system may be mounted on the PCA 70 or a subsea skid or may be integrated with the termination head 84h. The receptacle latch 77h may be pivoted to the base 77b, such as by a fastener, and be movable by the actuator 77a between an engaged position (Figure 4C) and a disengaged position (shown). The receptacle actuator 77a may be a piston and cylinder assembly connected to the frame 75 and the receptacle 77 may further include an interface (not shown), such as a hot stab, so that the ROV 20 may operate the receptacle actuator. The receptacle actuator 77a may also be in communication with the stab plate for operation via the subsea control line 84u. The receptacle latch 77h may include outer members and a crossbar (not shown) connected to each of the outer members by a shearable fastener 77f. The receptacle actuator 77a may be dual function so that the latch may be locked in either of the positions by either the ROV 20 or the control line.

[0063] Figure 4B illustrates deployment of the PCA 70. Once the packer 37 has been set, a grapple 69 may be connected to the wire rope 25 and engaged with the PCA 70. The wire rope 25 may then be used to lower the PCA 70 to the subsea wellhead 10 through the moonpool 23 of the vessel 21. The ROV 20 may guide landing of the PCA 70 onto the wellhead 10. The ROV 20 may then operate the wellhead connector 71 to fasten the PCA 70 to the subsea wellhead 10. The ROV 20 may then operate the grapple to release the PCA 70.

[0064] Figure 4C illustrates installation of the PCA 70 onto the subsea wellhead 10 and connection of the PCA to the support vessel 21. The subsea control system may be in electric, hydraulic, and/or optic communication with a surface control system of a control van 85 onboard a support vessel 21 via the subsea control line 84u, such as an umbilical. The subsea control system may further include a control pod having one or more control valves (not shown) in communication with the BOP stack 74 (via the stab plate) for selectively providing fluid communication with the accumulators 78 for operation of the BOP stack. Each pod control valve may include an electric or hydraulic actuator in communication with the control line 84u. The accumulators 78 may store pressurized hydraulic fluid for operating the BOP stack 74. Additionally, the accumulators 78 may be used for operating one or more of the other components of the PCA 70. The accumulators 78 may be charged via a conduit of the control line 84u or by the ROV 20.

[0065] Alternatively, the subsea control line 84u may be a hydraulic flying lead or an electrical cable.

[0066] The subsea control system may further include a PLC, a modem, a transceiver, and a power supply. The power supply may receive an electric power signal from a power cable of the control line 84u and convert the power signal to usable voltage for powering the subsea control system components as well as any of the PCA components. The PCA 20 may further include one or more pressure sensors (not shown) in communication with the PCA bore at various locations. The modem and transceiver may be used to communicate with the control van 85 via the control line 84u. The power cable may be used for data communication or the control line 84u may further include a separate data cable (electric or optic). The control van 85 may include a control panel (not shown) so that the various functions of the PCA 20 may be operated by an operator on the vessel 21.

[0067] The vessel 21 may further include a launch and recovery system (LARS) 86 for deployment of the termination head 84h and the control line 84u. The LARS 86 may include a frame, a control winch 86u, a boom 86b, a boom hoist 86h, a load winch 86d, and an HPU (not shown). The LARS 86 may be the A-frame type (shown) or the crane type (not shown). For the A-frame type LARS 86, the boom 86b may be an A-frame pivoted to the frame and the boom hoist 86h may include a pair of piston and cylinder assemblies, each piston and cylinder assembly pivoted to each beam of the boom and a respective column of the frame.

[0068] The control line 84u may include an upper portion and a lower portion fastened together by a shearable connection 87. Each winch 86d,u may include a drum having the respective control line 84u or load line 86n (Figure 4B) wrapped therearound and a motor for rotating the drum to wind and unwind the control line portion or load line. The load line 86n may be wire rope. Each winch motor may be electric or hydraulic. A control sheave and a load sheave may each hang from the boom 86b. The control line upper portion may extend through the control sheave and an end of the control line upper portion may be fastened to the shearable connection 87. The LARS 86 may have a platform for the termination head 84h to rest. The control line lower portion may be coiled and have a first end fastened to the shearable connection 87 and a second end fastened to the termination head 84h. The load line 86n may extend through the load sheave and have an end fastened to the lifting lugs of the termination head 84h, such as via a sling. Pivoting of the A-frame boom 86b relative to the platform by the piston and cylinder assemblies may lift the termination head 84h from the platform, over a rail of the vessel 21, and to a position over the waterline 1w. The load winch 86d may then be operated to lower the control line 84u and termination head 84h into the sea 1.

[0069] As the load winch 86d lowers the termination head 60, the control line lower portion may uncoil and be deployed into the sea 1 until the shearable connection 87 is reached. Once the shearable connection 87 is reached, a clump weight 89u may be fastened to a lower end of the control line upper portion. The termination head 84h may continue to be lowered using the load winch 86d until the shearable connection 87 and clump weight 89u are deployed from the LARS platform to over the waterline 1w. The control winch 86u may then be operated to support the termination head 84h using the control line 84u and the load line 86n slacked. The load line 86n and sling may be disconnected from the termination head 84h by the ROV 20. The termination head 84h may then be lowered to a landing depth using the control winch 86u.

[0070] As the control line 84u is being lowered to the landing depth, the ROV 20 may grasp the termination head 84h and assist in landing the termination head in the termination receptacle 77. Once landed, the ROV 20 may operate the actuator 77a to engage the receptacle latch 77h with the termination head 84h.

[0071] An upper portion of each fluid conduit 88n,o may be coiled tubing. The vessel 21 may further include a coiled tubing unit (CTU, not shown) for each fluid conduit 88n,o. Each CTU may include a drum having the coiled tubing wrapped therearound, a gooseneck, and an injector head for driving the coiled tubing, controls, and an HPU. A lower portion of each fluid conduit 88n,o may include a hose. The hose may be made from a flexible polymer material, such as a thermoplastic or elastomer or may be a metal or alloy bellows. An upper end of each hose may be connected to the respective coiled tubing by a dry beak connection 89n,o and a lower end of each hose may have a male coupling of the respective dry-break connection 83n,o connected thereto. During deployment of each fluid conduit 88n,o, a clump weight 89n,o may be fastened to the lower end of the respective coiled tubing.

[0072] Figures 5A and 5B illustrate the upper annulus cementing tool 90 of the annulus cementing system. The upper annulus cementing tool 90 may include a hanger 91, an extender 92, one or more of perforators, such as perforating guns 93, 94, and a stinger 95. The perforating guns 93, 94 may be disposed between the extender 92 and the stinger 95.

[0073] The hanger 91 may include a housing 96, a latch 97, and one or more stab seals 98u,b. The housing 96 may be tubular and have a flow bore formed therethrough. A coupling, such as a threaded box (not shown) or pin (shown), may be formed at a lower end of the housing 96 for connection with the extender 92. The housing 96 may have seal grooves formed in an outer surface thereof straddling the latch 97 and the stab seals 98u,b may be disposed in the respective seal grooves. Each stab seal 98u,b may be made from an elastomer or elastomeric copolymer and be operable to engage a respective seal bore 80u,b.

[0074] The latch 97 may be connected to the housing 96 at an upper end of the housing. The latch 97 may include an actuator, such as a cam 97c, and one or more fasteners, such as dogs 97d. The housing 96 may have a plurality of windows formed through a wall thereof for extension and retraction of the dogs 97d. The dogs 97d may be pushed outward by the cam 97c to engage the latch groove 80g, thereby longitudinally connecting the hanger 91 to the adapter 72. The cam 97c may be longitudinally movable relative to the housing 96 between an engaged position (shown) and a disengaged position (not shown). In the engaged position, the cam 97c may lock the dogs 97d in the extended position and in the disengaged position, the cam may be clear of the dogs, thereby freeing dogs to retract. The cam 97c may have an actuation profile formed in an outer surface thereof for pushing the dogs to the extended position, a latch profile formed in an inner surface thereof for engagement with a running tool 111 (Figure 5C), and a seal sleeve for maintaining engagement of the cam with a seal of the latch 97 regardless of the cam position. The cam 97c may also maintain engagement with another seal of the latch 97 regardless of the cam position. The latch 97 may further include an upper pickup shoulder formed in an inner surface of the housing 96 and engaged with the cam 97c when the cam is in the disengaged position and a lower landing shoulder formed in an outer surface of the housing 96 for seating against the landing shoulder 80s. The pickup shoulder may be used for supporting the upper annulus cementing tool 90 when carried by the running tool 111.

[0075] Alternatively, the latch 97 may be omitted from the hanger 91.

[0076] Each perforating gun 93, 94 may include a mandrel 99, an igniter 100, a charge carrier 101, and a housing 102. Each mandrel 99 may be tubular and have a flow bore formed therethrough. Each mandrel 99 may also have a coupling, such as a threaded pin or box, formed at each longitudinal end thereof for connection with the extender 92 or other perforating gun 93 at the upper end and for connection with the stinger 95 or other perforating gun 94 at the lower end. Each mandrel 99 may have a solid (port-less) wall 99w extending between the couplings to eliminate leak-paths between the bore thereof and the working annulus 67. Each mandrel 99 may be made of one-piece construction and/or may be seamless to further eliminate leak-paths. Each housing 102 may include two or more (pair shown) split sleeve portions 102a,b connected together, such as by lap joints (not shown) formed at radial ends thereof. The housing portions 102a,b may be connected to the mandrel 99, such as by one or more (four shown) threaded fasteners. Each housing 102 may also have a port 102p formed through a wall of one 102b of the portions 102a,b thereof.

[0077] Each mandrel 99 may have a recess formed in an outer surface thereof such that a chamber is formed between an outer surface of the mandrel and an inner surface of the respective housing 102. Longitudinal ends of each chamber may be formed by upper 99u and lower 99b shoulders of the respective mandrel 99. Each igniter 100 may be disposed in the respective chamber and include an electrical power source, such as a battery 105, an electronics package 106, a temperature probe 107, a pressure sensor 108, and an electric match 109. Each of the battery 105 and the electronics package 106 may be mounted in the chamber, such as by entrapment between the upper shoulder 99u and a threaded fastener screwed into the housing 102. The electric match 109 may be mounted in the chamber, such as by entrapment between a shoulder formed in an inner surface of the housing 102 and a threaded fastener (not shown) screwed into the housing.

[0078] Alternatively, the housing 102 may be omitted and the igniter 100 and charge carrier components may be disposed in pockets formed between inner and outer walls of the mandrel 99. In this alternative, the mandrel 99 may have an enlarged outer diameter to facilitate making of the pockets. Alternatively, the electronics package 106 may be encapsulated onto the housing 102.

[0079] Leads may be connected to ends of the battery 105 and extend to the electronics package 106 via the chamber. Leads may also be connected to the pressure sensor 108 and extend to the electronics package 106 via the chamber. Leads may also be connected to the electric match 109 and extend to the electronics package 106 via the chamber.

[0080] The electronics package 106 may include a control circuit 106c, a pressure circuit 106p, a temperature circuit 106c, and a match circuit 106m integrated on a printed circuit board 106b. The control circuit 106c may include a microcontroller, a memory unit, and a clock. The pressure circuit 106p may include a power converter, an amplifier, and an analog to digital converter for operating the pressure sensor 108 and reporting pressure measurements to the control circuit 106c. The temperature circuit 106t may include a power converter, an amplifier, and an analog to digital converter for operating the temperature probe 107 and reporting temperature measurements to the control circuit 106c. The match circuit 106m may include a power converter for operating the electric match 109.

[0081] The pressure sensor 108 may be connected to the housing port 102p for fluid communication with the working annulus 67. The temperature probe 107 may include a case, a thermometer, such as a thermocouple or thermistor, and a spring for biasing the thermometer into engagement with an outer surface of the mandrel wall 99w such that the thermometer is in thermal communication with the mandrel wall. The temperature probe 107 may be mounted on the circuit board 106b (shown) or the housing 102.

[0082] Each charge carrier 101 may be disposed in the respective chamber and include one or more (four shown) shaped charges 103 and one or more detonation cords 104. Each shaped charged 103 may be connected to the respective housing 102, such as by having a threaded coupling received in a respective threaded socket formed through a wall of the housing. The shaped charges 103 may be arranged in one or more (two shown) sets, each set having a plurality of shaped charges circumferentially spaced around the respective housing 102. The detonation cords 104 may connect the shaped charges 103 to the respective electric match 109.

[0083] The electric match 109 may include upper and lower cases screwed together and an electrode housed by and connected to the upper case, such as by threaded couplings. The electrode may have a prong which engages an electrical conductor extending through a passage of the upper case. A spring may be disposed between the conductor and a squib disposed in a passage of the lower case. The squib may include a bridgewire encased in a pyrogen. One of the detonation cords 104 may extend into the lower casing passage and be engaged with the squib for ignition thereby.

[0084] The control circuit 106c may be programmed with a firing protocol. The firing protocol may commence when the control circuit 106c detects a threshold pressure via communication with the pressure circuit 106p. The threshold pressure may be indicative of deployment of the upper annulus cementing tool 90 into the wellbore 2 or at least a substantial depth into the sea 1, such as being greater than or equal to one thousand psi (about seven kilopascals) and less than the expected pressure in the working annulus 67 at the deployment depth, such as being less than six thousand psi (about forty-two kilopascals). Once the control circuit 106c has detected the threshold pressure, the control circuit may commence an arming countdown. The arming countdown may correspond to an expected period of time until the abandonment operation has progressed to a point where it is desired to fire the respective perforation gun 93, 94, such as being between one-half and four hours. Once the arming countdown has been completed, the control circuit 106c may monitor a temperature of the respective mandrel wall 99w for detection of a firing signal communicated by achievement of a threshold temperature. Once the control circuit 106c detects the firing signal via the temperature circuit 106t, the control circuit may operate the electric match 109 via the match circuit 106m, thereby firing the shaped charges 103 via the detonation cords 104.

[0085] Alternatively, and/or as a backup to the temperature based firing signal, the control circuit 106c may also monitor pressure (in the upper portion) of the working annulus 67 for detection of the firing signal via a pressure pulse sequence. Each control circuit may be programmed with a different pressure pulse sequence so that the perforating guns 93, 94 may be individually fired. Alternatively, the arming countdown may be omitted from the firing protocol. Alternatively, the pressure threshold may be omitted from the firing protocol and the arming countdown started manually or when the battery 105 is connected to the electronics package 106.

[0086] The stinger 95 may include a body and a stab seal disposed in a seal groove formed in an outer surface of the body. The stinger body may have a guide nose to facilitate stabbing into the PBR 36.

[0087] Figure 5C illustrates deployment of the upper annulus cementing tool 90. Figure 5D illustrates hanging of the upper annulus cementing tool 90 from the PCA 70. Figure 5E illustrates stabbing of the upper annulus cementing tool 90 into the lower annulus cementing tool 35. Once the PCA 70 has been installed onto the subsea wellhead 10 and connected to the support vessel 21, a sixth BHA 110 may be connected to the wire rope 25 and deployed through the open sea 1 to the PCA 70. The sixth BHA 110 may include a cablehead, a collar locator, a running tool 111, and the upper annulus cementing tool 90.

[0088] The running tool 111 may be tubular and include a stroker, an ROV interface, a cablehead, an anchor, and a latch. The stroker, ROV interface, cablehead, and anchor, may each include a housing connected, such as by threaded connections. The stroker may include the housing and a shaft. The ROV interface may include one or more hot stabs for operating the stroker, the anchor, and the latch. The cablehead may connect the running tool 111 to the wire rope 25. The anchor may include two or more radial piston and cylinder assemblies and a die connected to each piston or two or more slips operated by a slip piston. The stroker, anchor, and latch of the running tool 111 may be similar to those of the setting tool 65.

[0089] The ROV 20 may be used to guide the stinger 95 into the PCA 70. The winch 24 may be operated to lower the upper annulus cementing tool 90 through the PCA 70 until the hanger 91 is adjacent to the landing profile 80 and the stinger 95 is adjacent to the PBR 36. The ROV 20 may then connect to the running tool 111 via hot stab and supply hydraulic fluid to operate the anchor and stroker thereof, thereby setting the hanger 91 into the into the landing profile 80 and stabbing the stinger 95 into the PBR 36. The ROV 20 may then operate the setting tool 111 to release the hanger 91, retract the stroker, and release the anchor. The ROV 20 may disconnect from the running tool 111 and the sixth BHA 110 (minus the upper annulus cementing tool 90) may be retrieved to the vessel 21.

[0090] Figure 5F illustrates deployment of a tool housing 112 to the PCA 70. Once the upper annulus cementing tool 90 has been set, the grapple 69 may be connected to the wire rope 25 and engaged with tool housing 112. The wire rope 25 may then be used to lower the tool housing 112 to the subsea wellhead 10 through the moonpool 23 of the vessel 21. The ROV 20 may guide landing of the tool housing 112 onto the PCA 70. The ROV 20 may then operate a PCA connector (not shown) of the tool housing 112 to fasten the tool housing to the PCA 70. The ROV 20 may then operate the grapple to release the tool housing 112.

[0091] Figure 6A illustrates a perforation assembly 115a of the annulus cementing system. The perforation assembly 115a may include a cablehead 130, a control sub 131, a heater 132, and a lower perforating gun 114a. The cablehead 130, the control sub 131, the heater 132, and the lower perforating gun 114a may be connected together, such as by threaded connections or flanges and studs or bolts and nuts. The control sub 131 may include a pressure sensor 131p, a thermometer 131t, a microcontroller (MCU) 131c, and a collar locator (not shown).

[0092] A junction cable may extend from the MCU 131c to the cablehead 130 for electrical connection to electrical conductors of the wireline 29, thereby providing electrical and data communication between the MCU 131c and the control van 85. The MCU 131c may include a control circuit, a pressure circuit, a temperature circuit, and a match circuit. Leads may provide electrical communication between the MCU 131c and the pressure sensor 131p, the thermometer 131t, the heater 132, and a firing head of the lower perforating gun 114a. The pressure sensor 131p may be in fluid communication with an exterior of the control sub 131. The thermometer 131t may be in thermal communication with a location adjacent to an outer surface of the heater 132 for monitoring operation thereof.

[0093] The heater 132 may include a mandrel and one or more (pair shown) heating elements disposed around and connected to the mandrel. The heating elements may be electrically connected in series or parallel and/or the heater 132 may include two or more sets of heating elements, each set connected in parallel such that the heater may still function if a heating element fails. Each heating element may be radiant including a case, a dielectric insulator, and a heating wire made from a high temperature electrically resistive material, such as a nickel-chromium alloy. The heating wire may be disposed in the case and the dielectric insulator may be disposed between the heating wire and an inner surface of the case. The dielectric insulator may be a high temperature material, such as magnesium oxide.

[0094] The lower perforating gun 114a may include the firing head and a charge carrier. The charge carrier may include a housing, a plurality of shaped charges, and detonation cord connecting the charges to the firing head. The electric match may ignite the detonation cord to fire the shaped charges.

[0095] Alternatively, the control sub 131c may include a battery, the perforating assembly 115a may be deployed using slickline or wire rope instead of the wireline 29, and/or the control sub 131c may be programmed to autonomously fire the perforating gun 114a and operate the heater 132.

[0096] Referring to Figure 9, alternatively, each heating element 133 may be inductive including a coil made from an electrically conductive material, such as aluminum, copper, or alloys thereof, wrapped around a magnetic, such as ferromagnetic or ferrimagnetic, core and the mandrel wall 99w may be made from a magnetic, such as ferromagnetic or ferrimagnetic, material.

[0097] Figures 6B-6G illustrate cement plugging of an annulus 113b (aka the B annulus) formed between the production 6 and the intermediate 5 casing strings. Figure 6B illustrates deployment of the perforation assembly 115a. Once the tool housing 112 has been installed onto the PCA 70, the perforation assembly 115a may be assembled with a lubricator 116, connected to the wireline 29, and deployed to the PCA 70.

[0098] The lubricator 116 may include an adapter, one or more stuffing boxes, a grease injector, a frame, a control relay, a tool catcher, a grease reservoir, and a grease pump. The adapter, stuffing boxes, grease injector, and tool catcher may each include a housing or body having a longitudinal bore therethrough and be connected, such as by flanges, such that a continuous bore is maintained therethrough.

[0099] The adapter may include a connector for mating with a connector profile of the tool housing 112, thereby fastening the lubricator 116 to the tool housing 112. The connector may be dogs or a collet. The adapter may further include a seal face or sleeve and a seal (not shown). The adapter may further include an actuator (not shown), such as a piston and a cam, for operating the connector. The adapter may further include an ROV interface so that the ROV 20 may connect to the connector, such as by a hot stab, and operate the connector actuator. The frame may be fastened to the adapter and the relay may be fastened to the frame. The grease pump and reservoir may also be fastened to the frame.

[0101] Each stuffing box may include a seal, a piston, and a spring disposed in the housing. A port may be formed through the housing in communication with the piston. The port may be connected to the control relay via a hydraulic conduit (not shown). When operated by hydraulic fluid, the piston may longitudinally compress the seal, thereby radially expanding the seal inward into engagement with the wireline 29. The spring may bias the piston away from the seal and be set to balance hydrostatic pressure.

[0102] The grease injector may include a housing integral with each stuffing box housing and one or more seal tubes. Each seal tube may have an inner diameter slightly larger than an outer diameter of the wireline 29, thereby serving as a controlled gap seal. An inlet port and an outlet port may be formed through the grease injector/stuffing box housing. A grease conduit (not shown) may connect an outlet of the grease pump with the inlet port and another grease conduit (not shown) may connect an inlet of the pump to the reservoir. The outlet port may discharge into the sea 1 or a grease trap. The grease pump may be electrically or hydraulically driven via cable/conduit (not shown) connected to the control relay and may be operable to pump grease (not shown) from the grease reservoir into the inlet port and along the slight clearance formed between the seal tube and the wireline 29 to lubricate the wireline, reduce pressure load on the stuffing box seals, and increase service life of the stuffing box seals.

[0103] The tool catcher may include a piston, a latch, such as a collet, a stop, a piston spring, and a latch spring disposed in a housing thereof. The collet may have an inner cam surface for engagement with the cablehead and the catcher housing may have an inner cam surface for operation of the collet. The latch spring may bias the collet toward a latched position. The collet may be movable from the latched position to an unlatched position by operation of the piston. The catcher housing may have a hydraulic port formed through a wall thereof in fluid communication with the piston. A hydraulic conduit (not shown) may connect the hydraulic port to the control relay. The piston may be biased away from engagement with the collet by the piston spring. When operated, the piston may engage the collet and move the collet upward along the housing cam surface and into engagement with the stop, thereby moving the collet to the unlatched position.

[0104] Figure 6C illustrates firing of the lower perforating gun 114b to perforate the production casing 6c. Once the lubricator 116 has landed onto the PCA 70, the ROV 20 may operate the connector and install a jumper (not shown) between the lubricator control relay and the PCA 70. The stuffing boxes and grease injector may be activated and the tool catcher operated to release the perforation assembly 115a. The perforation assembly 115a may then be lowered through the annulus cementing tools 35, 90 to a depth below the cementing plug 40 and above the lower bridge plug 33b. Once the perforation assembly 115a has been deployed to the firing depth, a firing command may be sent to the MCU 131c from the control van 85 via the wireline 29. The MCU 131c may then supply electrical power from the wireline 29 to the firing head of the lower perforating gun 114a to fire the lower perforating gun into the production casing 6c, thereby forming lower perforations 117b through a wall thereof. The shaped charges of the lower perforating gun 114b may have a charge strength sufficient to form the lower perforations 117b through a wall of the production casing 6c without damaging a wall of the intermediate casing 5c, thereby providing access to the B annulus 113b.

[0105] Figure 6D illustrates operation of the perforation assembly 115a to activate the perforating gun 94 of the upper annulus cementing tool 90. Once the lower perforations 117b have been formed, the perforation assembly 115a may be raised into the upper annulus cementing tool 90 until the heater 132 is adjacent to the temperature probe 107 of the perforating gun 94. A heating command may be sent to the MCU 131c from the control van 85 via the wireline 29. The MCU 131c may then supply electrical power from the wireline 29 to the heater 132, thereby heating the respective mandrel wall 99w until the threshold temperature is achieved.

[0106] Since the well has not been producing for some time prior to and during abandonment of the lower portion thereof, temperature in the upper portion thereof has cooled to a temperature corresponding to that of the seafloor 1f, such as substantially below room temperature. The threshold temperature may be selected to be substantially greater than the seafloor temperature, such as room temperature. As an additional safety measure, the threshold temperature may also be selected to be substantially greater than room temperature and even substantially greater than ambient temperature aboard the vessel 21, such as greater than or equal to one hundred degrees Fahrenheit (thirty-eight degrees Celsius). The threshold temperature may also be less than or substantially less than production temperature in the upper portion of the well, such as less than or equal to two hundred degrees Fahrenheit (ninety-three degrees Celsius).

[0107] Alternatively, the mandrel walls 99w of the perforating guns 93, 94 may each be coated or covered with a thermally insulating blanket to reduce the required heating capacity of the heater 132.

[0108] Figure 6E illustrates firing of the perforating gun 94 of the upper annulus cementing tool 90 to again perforate the production casing 6c. Once the threshold temperature has been achieved to complete the firing protocol, the control circuit 106c of the perforating gun 94 may supply electrical power from the battery 105 to the electric match 109 via the match circuit 109m, thereby firing the perforating gun into the production casing 6c and forming upper perforations 117u through the wall thereof. The shaped charges 103 of the perforating gun 94 may have a charge strength sufficient to form the upper perforations 117u through a wall of the production casing 6c without damaging a wall of the intermediate casing 5c, thereby providing further access to the B annulus 113b.

[0109] Once the upper perforations 117u have been formed, the perforation assembly 115a may be retrieved to the lubricator 116, the blind-shear BOP 74b closed, and the lubricator and the perforation assembly dispatched from the PCA 70 to the vessel 21.

[0110] Figure 6F illustrates pumping cement slurry 121 into the B annulus 113b. Figure 6G illustrates launching of the cementing plug 40 of the lower annulus cementing tool 35. Conditioner 120 may then be pumped from the vessel 21, down the supply fluid conduit 88n, through the conduit 81n and fluid sub port 73p, through a bore of the PCA 70, through the bores of the upper 90 and lower 35 annulus cementing tools. The conditioner 120 may flow through the bore of the production casing 6c, enter the B annulus 113b via the lower perforations 117b, and exit the B annulus via the upper perforations 117u. The conditioner 120 may continue up the working annulus 67, through the subsea wellhead 10, and into the return fluid conduit 88o via the fluid passage 72p and conduit 81o.

[0111] Once the B annulus 113b has been conditioned, a quantity of cement slurry 121 followed by a release plug 122, such as a ball, may then be pumped from the vessel 21 and into the supply fluid conduit 88n. The cement slurry 121 and release plug 122 may be driven through the supply fluid conduit 81n by chaser fluid 123. The cement slurry 121 and release plug 122 may continue through the conduit 81n and fluid sub port 73p, through a bore of the PCA 70, and through the bore of the upper annulus cementing tool 90. As the cement slurry 121 flows through the bore of the lower annulus cementing tool 35 and exits into the bore of the production casing 6, the release plug 122 may land in the seat of the cementing plug 40 and continued pumping of the chaser fluid 123 may increase pressure in the bores of the annulus cementing tools 35, 90 until a fluid force exerted thereon is sufficient to fracture the shearable fasteners 41, thereby releasing the cementing plug from the nipple 38.

[0112] The released cementing plug 40 and seated plug 122 may drive the cement slurry 121 into the B annulus 113b via the lower perforations 117b. The displaced conditioner 120 may flow from the B annulus 113b into the working annulus 67 via the upper perforations 117u. The displaced conditioner 120 may continue up the working annulus 67, through the subsea wellhead 10, and into the return fluid conduit 88o via the fluid passage 72p and conduit 81o. The displaced conditioner 120 may continue up the return fluid conduit 88o to the vessel 21.

[0113] Pumping of the chaser fluid 123 may be halted due to an increase in pressure resulting from the cementing plug 40 reaching the lower perforations 117b or once a desired volume of chaser fluid 123 has been pumped. The lower perforations 117b may be spaced from the lower bridge plug 33b to leave a length of cement slurry 121 in the production casing bore. Densities of the conditioner 121, cement slurry 122, and chaser fluid 123 may correspond so that the cement slurry 121 in the B annulus 113b is in a balanced condition. The cement slurry 121 in the B annulus 113b and production casing bore may then be allowed to cure, thereby forming respective B annulus cement plug 124b and production casing bore plug 124p.

[0114] Figures 7A-7G illustrate cement plugging of an annulus 113c (aka the C annulus) formed between the intermediate 5 and the surface 4 casing strings. Figure 7A illustrates deployment of a second perforation assembly 115b. Once the B annulus cement plug 124b has formed, a second perforation assembly 115b may be assembled with the lubricator 116, connected to the wireline 29, and deployed to the PCA 70. The second perforation assembly 115b may be similar to the (first) perforation assembly 115a except for having a second lower perforating gun 114b instead of the (first) lower perforating gun 114a.

[0115] Figure 7B illustrates firing of the second lower perforating gun 114b to perforate the production 6 and intermediate 5 casing strings. Once the lubricator 116 has landed onto the PCA 70, the ROV 20 may operate the connector and install the jumper between the lubricator control relay and the PCA 70. The stuffing boxes and grease injector may be activated, the blind-shear BOP 74b opened, and the tool catcher operated to release the second perforation assembly 115b. The second perforation assembly 115b may then be lowered through the annulus cementing tools 35, 90 to a depth above the cementing plug 40. Once the second perforation assembly 115b has been deployed to the firing depth, a firing command may be sent to the MCU 131c from the control van 85 via the wireline 29. The MCU 131c may then supply electrical power from the wireline 29 to the firing head of the second lower perforating gun 114b to fire the second lower perforating gun through the production casing 6c, through the B annulus cement plug 124b, and through a wall of the intermediate casing 5c, thereby forming lower perforations 125b. The second lower perforating gun 114b may be similar to the first lower perforating gun 114a except for having shaped charges with a charge strength sufficient to form the lower perforations 125b through the wall of the production 5c and intermediate 6c casings and the B annulus cement plug 124b without damaging a wall of the surface casing 4c, thereby providing access to the C annulus 113c.

[0116] Figure 7C illustrates operation of the second perforation assembly 115b to activate a second perforating gun 93 of the upper annulus cementing tool 90. Once the lower perforations 125b have been formed, the second perforation assembly 115b may be raised into the upper annulus cementing tool 90 until the heater 132 is adjacent to the temperature probe 107 of the second perforating gun 93. A heating command may be sent to the MCU 131c from the control van 85 via the wireline 29. The MCU 131c may then supply electrical power from the wireline 29 to the heater 132, thereby heating the respective mandrel wall 99w until the threshold temperature is achieved.

[0117] The threshold temperature of the second perforating gun 93 may be the same as the threshold temperature of the (first) perforating gun 94 and the guns may be spaced sufficiently such that the mandrel wall 99w of the second perforating fun 93 is not heated significantly during activation of the first perforating gun 94.

[0118] Alternatively, the threshold temperature of the second perforating gun 94 may be substantially greater than the threshold temperature of the first perforating gun 93.

[0119] Figure 7D illustrates firing of a second perforating gun 93 of the upper annulus cementing tool 90 to again perforate the production 6 and intermediate 5 casing strings. Once the threshold temperature has been achieved to complete the firing protocol, the control circuit 106c of the second perforating gun 93 may supply electrical power from the battery 105 to the electric match 109 via the match circuit 109m, thereby firing the second perforating gun through the production casing 6c and through the wall of the intermediate casing 5c, thereby forming upper perforations 125u through the wall thereof. The shaped charges 103 of the second perforating gun 93 may have a charge strength sufficient to form the upper perforations 125u through a wall of the production casing 6c without damaging a wall of the intermediate casing 5c, thereby providing further access to the C annulus 113c.

[0120] Once the upper perforations 125u have been formed, the second perforation assembly 115b may be retrieved to the lubricator 116, the blind-shear BOP 74b closed, and the lubricator and the second perforation assembly dispatched from the PCA 70 to the vessel 21.

[0121] Figure 7E illustrates pumping cement slurry 121 into the C annulus 113c. Conditioner 120 may then be pumped from the vessel 21, down the supply fluid conduit 88n, through the conduit 81n and fluid sub port 73p, through a bore of the PCA 70, through the bores of the upper 90 and lower 35 annulus cementing tools. The conditioner 120 may flow through the bore of the production casing 6c, enter the C annulus 113c via the lower perforations 125b, and exit the C annulus via the upper perforations 125u. The conditioner 120 may continue up the working annulus 67, through the subsea wellhead 10, and into the return fluid conduit 88o via the fluid passage 72p and conduit 81o.

[0122] A quantity of cement slurry 121 may then be pumped from the vessel 21 and into the supply fluid conduit 88n. The cement slurry 121 may be driven through the supply fluid conduit 81n by the chaser fluid 123. The cement slurry 121 may continue through the conduit 81n and fluid sub port 73p, through a bore of the PCA 70, through the bore of the upper annulus cementing tool 90. The cement slurry 121 may continue into the C annulus 113c via the lower perforations 125b. The displaced conditioner 120 may flow from the C annulus 113c into the working annulus 67 via the upper perforations 125u. The displaced conditioner 120 may continue up the working annulus 67, through the subsea wellhead 10, and into the return fluid conduit 88o via the fluid passage 72p and conduit 81o. The displaced conditioner 120 may continue up the return fluid conduit 88o to the vessel 21. Pumping of the chaser fluid 123 may be halted once a desired volume of chaser fluid 123 has been pumped. Densities of the conditioner 120, cement slurry 121, and chaser fluid 123 may correspond so that the cement slurry in the C annulus 113c is in a balanced condition. The cement slurry 121 in the C annulus 113c may then be allowed to cure, thereby forming the C annulus cement plug 124c (Figure 7G).

[0123] Figure 7F illustrates deployment of the bore plug 39. Figure 7G illustrates setting of the bore plug 39 in the lower annulus cementing tool 35. Once the C annulus cement plug 124c has formed, a seventh BHA 118 may be assembled with the lubricator 116 and connected to the wireline 29 and deployed through the open sea 1 to the tool housing 112. The seventh BHA 118 may include a cablehead, a collar locator, a setting tool 119, and the bore plug 39. The setting tool 119 may be similar to the setting tool 65.

[0124] Once the lubricator 116 has landed onto the PCA 70, the ROV 20 may operate the connector and install the jumper. The stuffing boxes and grease injector may be activated and then the blind-shear BOP 74b opened. The tool catcher may be operated to release the seventh BHA 118 and the seventh BHA may then be lowered through the upper annulus cementing tool 90 and into the lower annulus cementing tool 35 to a depth adjacent the nipple 38. The setting tool 119 may then be operated via the wireline 29 to install the bore plug 39 into the nipple profile. The setting tool 119 may then be operated via the wireline 29 to release the bore plug 39 and the seventh BHA 118 (minus the bore plug) may then be retrieved to the lubricator 116 and the lubricator and the seventh BHA dispatched from the PCA 70 to the vessel 21.

[0125] Figures 8A-8C illustrate abandonment of the subsea wellhead 10. Once the bore plug 39 has been reinstalled, the grapple 69 may be connected to the wire rope 25 and deployed through the open sea 1 to the tool housing 112. The ROV 20 may guide landing of the grapple 69 onto the tool housing 112. The ROV 20 may then operate the grapple 69 to engage the tool housing 112. The grapple 69 and engaged tool housing 112 may be dispatched from the PCA 70 to the vessel 21. The dry break connections 83n,o and the termination head 84h may be released from the PCA 70 and the fluid conduits 88n,o and the control line 84u retrieved to the vessel 21. The grapple 69 may be redeployed through the open sea 1 to the PCA 70. The ROV 20 may then operate the grapple 69 to engage the PCA 70 and operate the wellhead connector 71 to disengage the wellhead 10. The grapple 69 and engaged PCA 70 may be dispatched from the wellhead 10 to the vessel 21.

[0126] Figure 8A illustrates deployment of an upper bridge plug 33u. Figure 8B illustrates setting the upper bride plug 33u in the production casing 6c. Once the PCA 70 has been retrieved to the vessel 21, the fourth BHA 34 (with the upper bridge plug 33u) may be connected to the wireline 29 and deployed through the open sea 1 to the subsea wellhead 10. The fourth BHA 34 may be lowered through the subsea wellhead 10 into the production casing 6c and deployed to a depth therein above the upper C annulus perforations 125u. Once the fourth BHA 34 has been deployed to the setting depth, electrical power may then be supplied to the BHA via the wireline 29 to operate the setting tool, thereby expanding the upper bridge plug 33u against the inner surface of the production casing 6c. Once the upper bridge plug 33u has been set, the plug may be released from the setting tool by exerting tension on the wireline 29 to fracture the shearable fastener. The fourth BHA 34 (minus the upper bridge plug 33u) may then be retrieved to the vessel 21.

[0127] Figure 8C illustrates cement plugging a bore of the production casing 6c. Once the upper bridge plug 33u has been set, cement slurry may be pumped into the production casing bore down to the upper bridge plug 33u and allowed to cure, thereby forming a top cement plug 126. The wellhead 10 may then be left utilizing the casing packoffs as additional barriers.

[0128] Alternatively, the lower annulus cementing tool 35 may have an additional upper cementing plug. The upper cementing plug may be a wiper plug including a finned seal and a plug body. The finned seal may be made from an elastomer or elastomeric copolymer and attached to an outer surface of the plug body. The plug body may be tubular, may be made from a metal or alloy, may have an upper stem portion, may have a seat formed in an inner surface thereof, and may have a coupling, such as a lap, formed in a lower end thereof. The stem portion may be received by the nipple lap and one or more (pair shown) shearable fasteners may be inserted into respective sockets formed through a wall of the nipple 38 and received by respective indentations formed in an outer surface of the stem portion, thereby releasably connecting the upper cementing plug and the nipple. The stem portion of the lower cementing plug 40 may be received by the upper cementing plug lap and the shearable fasteners 41 may be inserted into respective sockets formed through a wall of the upper cementing plug and received by the respective indentations formed in an outer surface of the stem portion, thereby releasably connecting the cementing plugs. The seat of the upper cementing plug may have a minor diameter greater than or equal to a major diameter of the seat of the lower cementing plug 40 such that the release plug 122 may travel freely through the upper cementing plug. When pumping the cement slurry 121 for the C annulus 113c, a second release plug, such as a ball, may be pumped from the vessel 21 and into the supply fluid conduit 88n between the cement slurry and the chaser fluid 123. The cement slurry 121 and second release plug 130 may be driven through the supply fluid conduit 81n by the chaser fluid 123. The cement slurry 121 and second release plug may continue through the conduit 81n and fluid sub port 73p, through a bore of the PCA 70, and through the bore of the upper annulus cementing tool 90. As the cement slurry 121 flows through the bore of the alternative lower annulus cementing tool and exits into the bore of the production casing 6, the second release plug may land in the seat of the upper cementing plug and continued pumping of the chaser fluid 123 may increase pressure in the bores of the annulus cementing tools until a fluid force exerted thereon is sufficient to fracture the shearable fasteners, thereby releasing the upper cementing plug from the nipple 38. The force required to fracture the shearable fasteners may be greater than the force required to fracture the shearable fasteners 41 such that release of the cementing plug 40 does not prematurely release the upper cementing plug. The released upper cementing plug and seated second release plug may drive the cement slurry 121 into the C annulus 113c via the lower perforations 125b. The displaced conditioner 120 may flow from the C annulus

113c into the working annulus 67 via the upper perforations 125u. The displaced conditioner 120 may continue up the working annulus 67, through the subsea wellhead 10, and into the return fluid conduit 88o via the fluid passage 72p and conduit 81o. The displaced conditioner 120 may continue up the return fluid conduit 88o to the vessel 21. Pumping of the chaser fluid 123 may be halted due to an increase in pressure resulting from the upper cementing plug reaching the lower perforations 125b or once a desired volume of chaser fluid 123 has been pumped. The cement slurry 121 in the C annulus 113c may then be allowed to cure, thereby forming the C annulus cement plug 124c.

[0129] Alternatively, the lower annulus cementing tool 35 may have an extender instead of the cementing plug 40 and a modified nipple. The modified nipple may be tubular, have a coupling, such as a threaded box or pin, formed at an upper end thereof and in engagement with the adapter coupling, thereby connecting the nipple and the packer 37. The modified nipple may also have the receiver profile formed in an inner surface thereof for fastening of the bore plug thereto. The modified nipple may also have a coupling, such as a threaded box (not shown) or pin (shown), formed at a lower end thereof and in engagement with a mating upper coupling of the extender, thereby connecting the modified nipple and the extender. The extender may have an entry guide profile formed in a lower end thereof. The extender may be tubular and have a bore corresponding to the modified nipple bore and a length sufficient such that the extender lower end is adjacent to and above the lower B annulus 117b and modified lower C annulus perforations. Cementation of the B annulus 113b may be similar to that for the lower annulus cementing tool 35 except for omission of the release plug 122. Cementation of the C annulus 113c may be similar to that for the lower annulus cementing tool 35 except that the modified lower C annulus perforations may be formed adjacent to (and still above) the lower B annulus perforations 117b.

[0130] Alternatively, the lower annulus cementing tool 35 may have an extender instead of the cementing plug 40, the modified nipple, a modified packer, and an upper adapter instead of the PBR 36. The extender may be tubular, may have seal bore formed at an upper end thereof for receiving the stinger of the upper annulus cementing tool, and may have a coupling, such as a threaded box (not shown) or pin (shown), formed at a lower end thereof and in engagement with the mating box of the modified nipple, thereby connecting the modified nipple and the extender. The upper adapter may be tubular, may have a coupling, such as a threaded box (shown) or pin (not shown), formed at an upper end thereof and in engagement with the mating pin of the modified nipple, thereby connecting the modified nipple and the upper adapter, and have a coupling, such as a thread, formed adjacent to a lower end thereof for connection with an outer sleeve of the modified packer. The modified packer may be similar to the packer 37 except that a lower adapter thereof may have an entry guide profile instead of the pin like the adapter 49. The extender may have a length sufficient such that the packer lower adapter is adjacent to and above the lower B annulus 117b and the modified lower C annulus perforations. Cementation of the B annulus 113b may be similar to that for the lower annulus cementing tool 35 except for omission of the release plug 122. Cementation of the C annulus 113c may be similar to that for the lower annulus cementing tool 35 except that the modified lower C annulus perforations may be formed adjacent to (and still above) the lower B annulus perforations 117b.

[0131] Alternatively, the lower annulus cementing tool 35 may have an extender instead of the cementing plug 40, a lower packer 162, and a modified nipple. The extender may be tubular, may have a coupling, such as a threaded box (shown) or pin (not shown), formed at an upper end thereof and in engagement with the mating box of the packer adapter, thereby connecting the extender and the (upper) packer 37, and may have a coupling, such as a threaded box (not shown) or pin (shown), formed at a lower end thereof and in engagement with a mating box of the lower packer, thereby connecting the lower packer and the extender. The lower packer may include a mandrel, a bladder sleeve, a bladder, and one or more retainers, such as nuts, and an inflator. The mandrel may be tubular and have a flow bore formed therethrough. The mandrel may have a coupling, such as a threaded pin or box, formed at each longitudinal end thereof for connection with the extender at the upper end and for connection with the modified nipple at the lower end. The lower packer may further include various seals disposed between various interfaces thereof. The bladder assembly may be connected to the mandrel, such as by entrapment between shoulders of the mandrel. Each nut may be connected to the bladder sleeve, such as by threaded couplings. Each nut may have a groove formed therein for receiving respective reinforcement elements, such as spring bars. The bladder may be made from an elastomer or elastomeric copolymer. The bladder may be molded onto the assembled nuts, sleeve, and spring bars. An inner surface of the bladder may be in fluid communication with one or more ports formed through a wall of the bladder sleeve. The ports may provide fluid communication with an inflation passage formed between the bladder sleeve and the mandrel. The inflator may be in fluid communication with the inflation passage. The inflator may include an inflation port formed through a wall of the mandrel, a check valve disposed in the inflation passage, and an isolation sleeve. The check valve may be oriented to allow flow from the inflation port to the inflation passage but to prevent reverse flow therethrough, thereby maintaining inflation of the bladder. The isolation sleeve may be similar to the isolation sleeve 109 and may selectively open or close the inflation ports. The modified nipple may be tubular, have a coupling, such as a threaded box (shown) or pin (not shown), formed at an upper end thereof and in engagement with the lower packer coupling, thereby connecting the nipple and the lower packer. The modified nipple may also have the receiver profile formed in an inner surface thereof for fastening of the bore plug thereto. The modified nipple may also have an entry guide profile formed in a lower end thereof. Running and installation of the alternative lower annulus cementing tool may be similar to that of the lower annulus cementing tool 35 except for additional steps after setting of the upper packer 37. Before installation of the PCA 70, an inflation tool (not shown) may be deployed using the wireline 29 into the alternative lower annulus cementing tool. The inflation tool may be operated to set the bore plug in the modified nipple, engage and open the lower packer isolation sleeve, and supply pressurized fluid to the bladder, thereby inflating the bladder. The inflation tool may then close the isolation sleeve and remove the bore plug. In a further alternative, the lower packer may be inflated after installation of the PCA 70 and upper annulus cementing tool 90 and before forming the lower B annulus perforations 117b by deploying the shifting tool 119, installing the bore plug, and injecting pressurized inflation fluid into the annulus cementing tools, thereby inflating the bladder. The shifting tool 119 may then remove the bore plug. The extender may have a length sufficient such that the modified nipple lower end is adjacent to and above the lower B annulus 117b and the modified lower C annulus perforations. Cementation of the B annulus 113b may be similar to that for the lower annulus cementing tool 35 except for omission of the release plug 122. Cementation of the C annulus 113c may be similar to that for the lower annulus cementing tool 35 except that the modified lower C annulus perforations may be formed adjacent to (and still above) the lower B annulus perforations 117b.

[0132] While the foregoing is directed to embodiments of the present disclosure, other and further embodiments of the disclosure may be devised without departing from the basic scope thereof, and the scope of the invention is determined by the claims that follow.

Claims:

1. A method for triggering a tool disposed in a wellbore, comprising:
running the tool into the wellbore;
running a heater into the wellbore and into a bore of the downhole tool; and
while in the bore, operating the heater to heat a portion of the downhole tool to a threshold temperature,
wherein a control circuit of the downhole tool detects the threshold temperature and operates an actuator of the downhole tool in response to the detection.

2. The method of claim 1, wherein the heater is radiant.

3. The method of claim 1, wherein the heater is inductive.

4. The method of claim 1, wherein:
the downhole tool is a perforating gun, and
operation of the actuator fires the perforating gun.

5. The method of claim 4, wherein:
the method further comprises:
setting a packer of a lower cementing tool against a bore of an inner casing hung from a subsea wellhead; and
fastening a pressure control assembly (PCA) to the subsea wellhead,
the perforating gun is part of an upper cementing tool,
the perforating gun is run into the wellbore by hanging the upper cementing tool from the PCA and stabbing the upper cementing tool into a polished bore receptacle of the lower cementing tool, and
operation of the perforating gun perforates the inner casing wall above the packer.

6. The method of claim 5, further comprising perforating a wall of the inner casing below the packer.

7. The method of claim 6, further comprising pumping cement slurry through bores of the cementing tools and into an inner annulus formed between the inner casing and an outer casing hung from the subsea wellhead.

8. The method of claim 7, wherein:

the cement slurry is followed by a release plug through bores of the cementing tools,

the release plug engages and launches a cementing plug from the lower cementing tool, and

the cementing plug drives the cement slurry into the inner annulus.

9. The method of claim 6, wherein the inner casing wall is perforated below the packer before being perforated above the packer.

10. The method of claim 6, wherein:

the heater is run into the wellbore using wireline,

the heater is part of a perforation assembly further comprising a second perforating gun, and

the inner casing wall is perforated below the packer by firing the second perforating gun using the wireline.

11. The method of claim 10, further comprising:

fastening a tool housing to the PCA; and

after fastening the tool housing to the PCA:

deploying the second perforating gun through open sea with a lubricator and the wireline;

fastening the lubricator to the tool housing; and

lowering the second perforating gun through the cementing tool bores.

12. The method of claim 7, wherein:

the upper cementing tool further comprises a second perforating gun, and

the method further comprises:

rerunning the heater into a bore of the second perforating gun; and

while in the bore, operating the heater to heat a portion of the second perforating gun to the threshold temperature,

a control circuit of the second perforating gun detects the threshold temperature and fires the second perforating gun in response to the detection, thereby perforating walls of the inner and outer casings above the packer.

13. The method of claim 12, further comprising perforating the inner and outer casing walls below the packer.

14. The method of claim 13, further comprising pumping a second cement slurry through bores of the cementing tools and into an outer annulus formed between the outer casing and a third casing hung from the subsea wellhead.

15. The method of claim 5, further comprising deploying the lower cementing tool through open sea to the subsea wellhead before fastening the PCA to the subsea wellhead.

16. The method of claim 5, wherein the method is performed riserlessly.

17. The method of claim 7, further comprising, after curing of the cement slurry:

retrieving the PCA and the upper cementing tool;

setting a bridge plug in the inner casing bore; and

forming a cement plug on the set bridge plug.

18. A perforating gun, comprising:

a tubular mandrel having a solid wall and a bore therethrough;

a thermometer in thermal communication with the wall;

a control circuit in communication with the thermometer;

a battery in communication with the control circuit;

an electric match in communication with the control circuit;

detonation cord in communication with the electric match; and

one or more shaped charges connected to the detonation cord.

19. A perforation system, comprising:

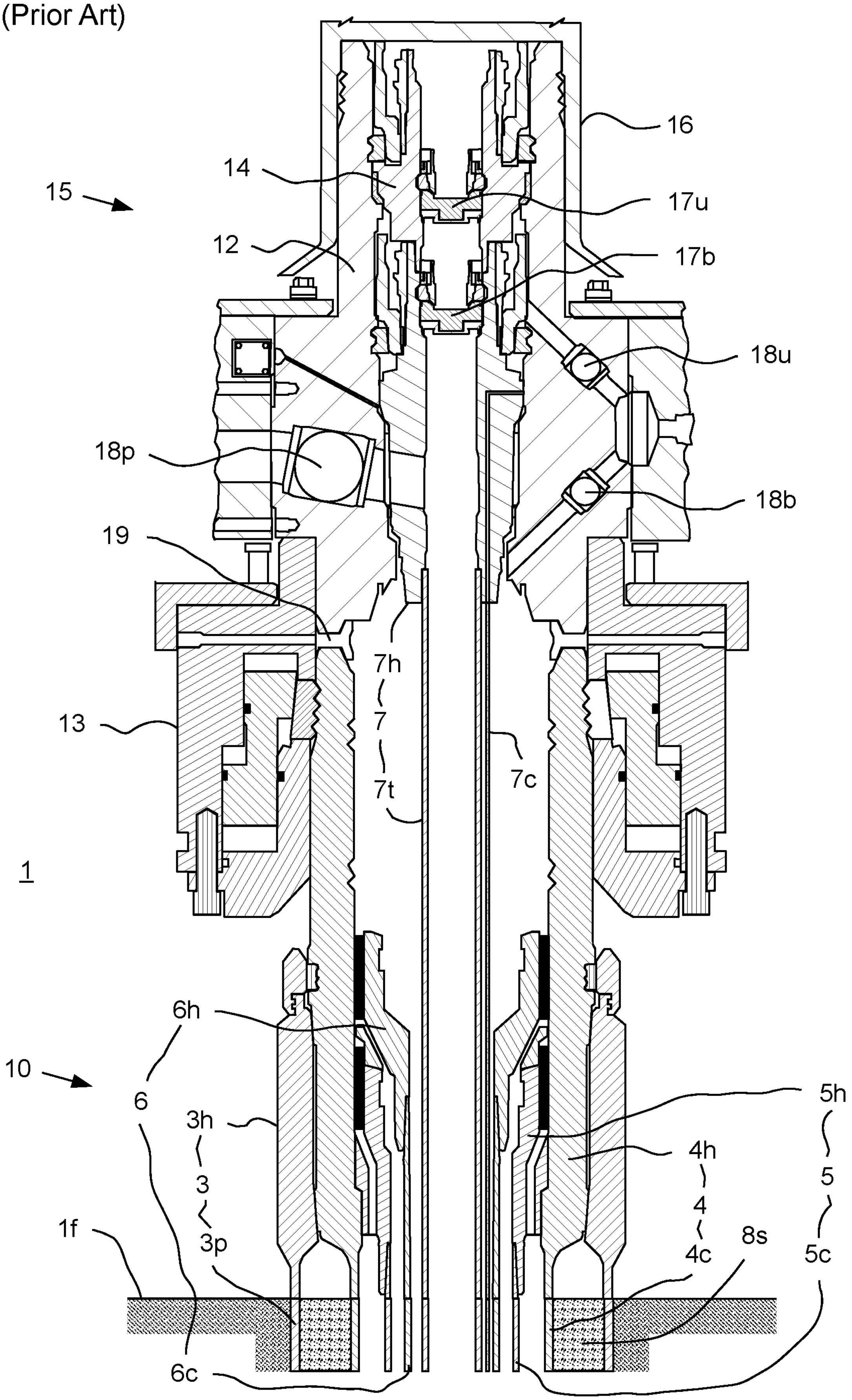
the perforating gun of claim 18; and

a submersible heater for deployment into the bore and operable to heat the mandrel wall to a threshold temperature,

wherein the control circuit is operable to activate the electric match in response to detection of the threshold temperature.

20. The perforation system of claim 19, further comprising a second perforating gun connected to the submersible heater for deployment through the bore.

FIG. 1A
(Prior Art)



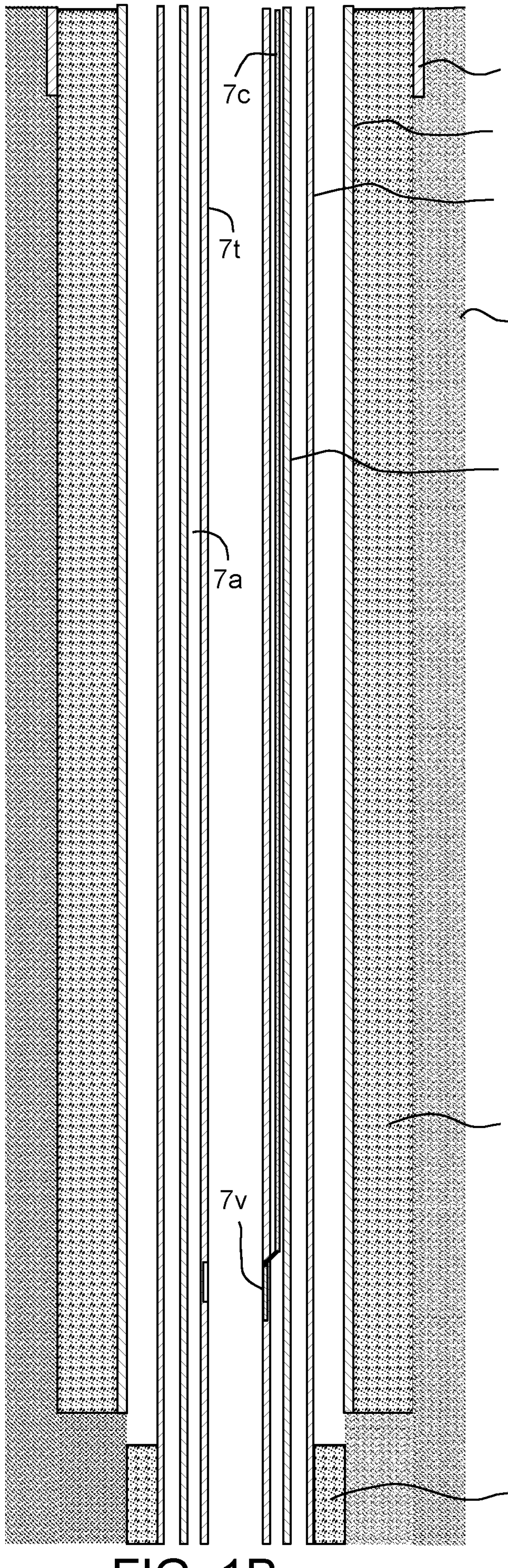


FIG. 1B (Prior Art)

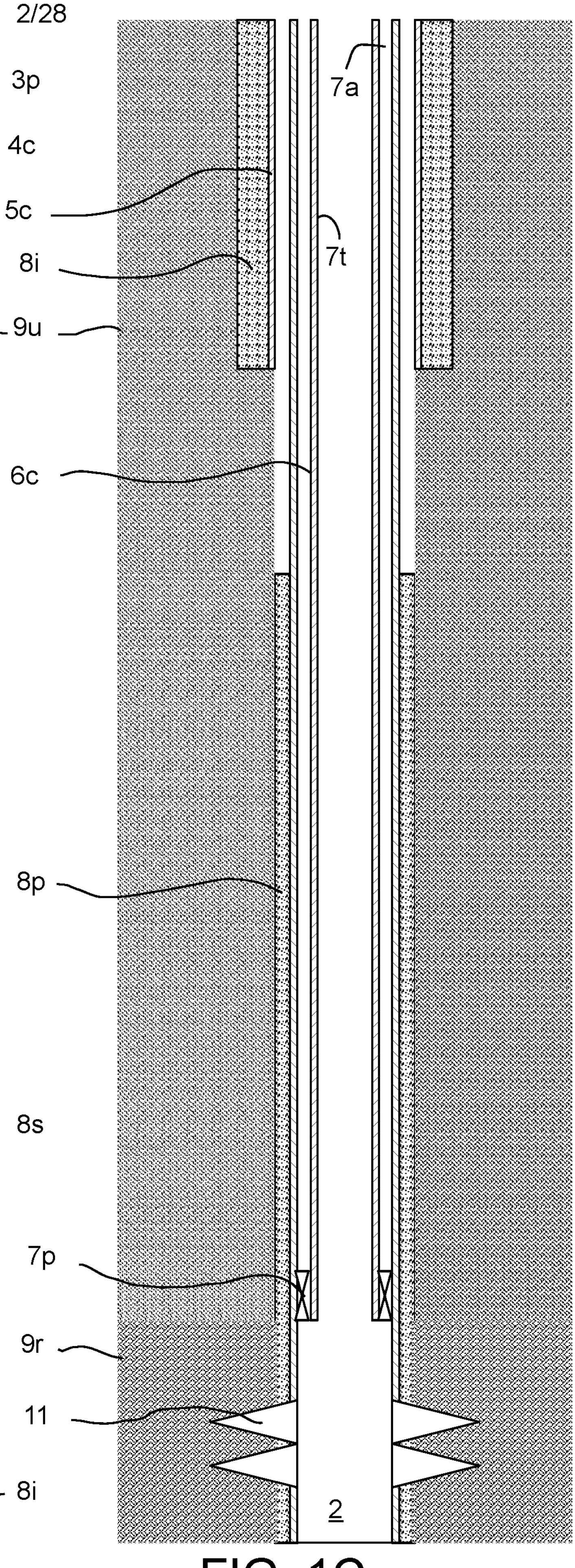
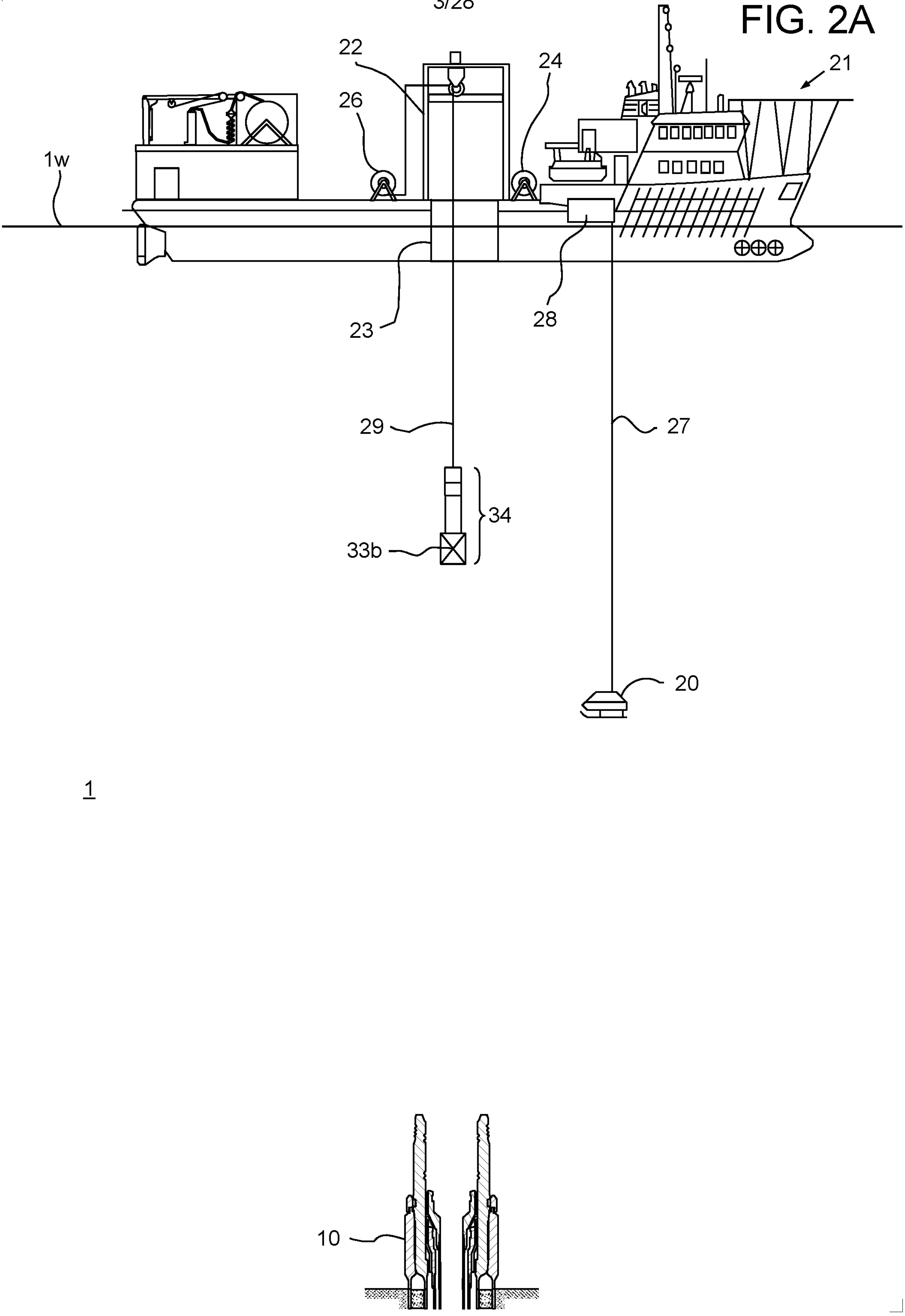


FIG. 1C (Prior Art)

FIG. 2A



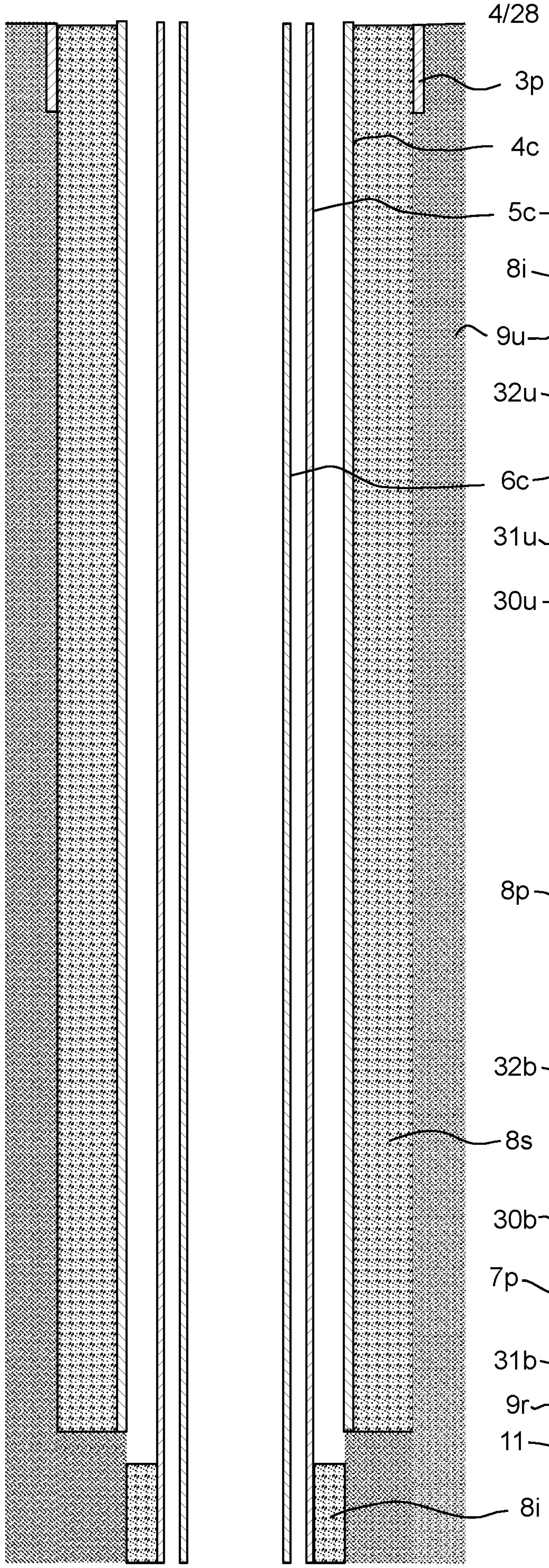


FIG. 2B

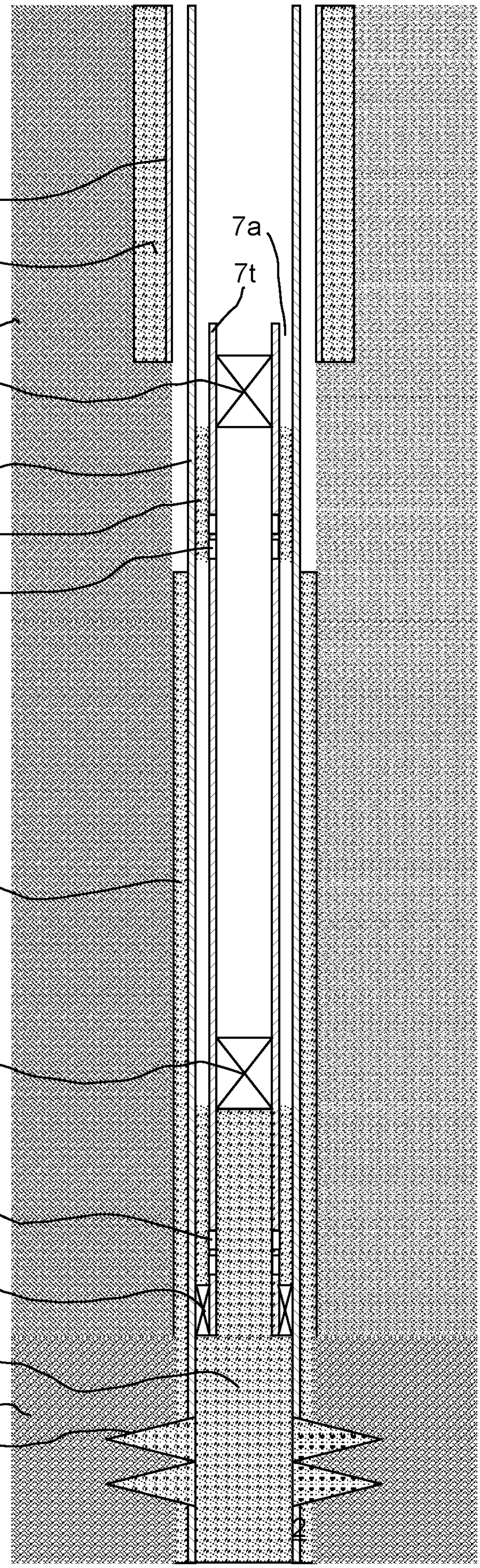


FIG. 2C

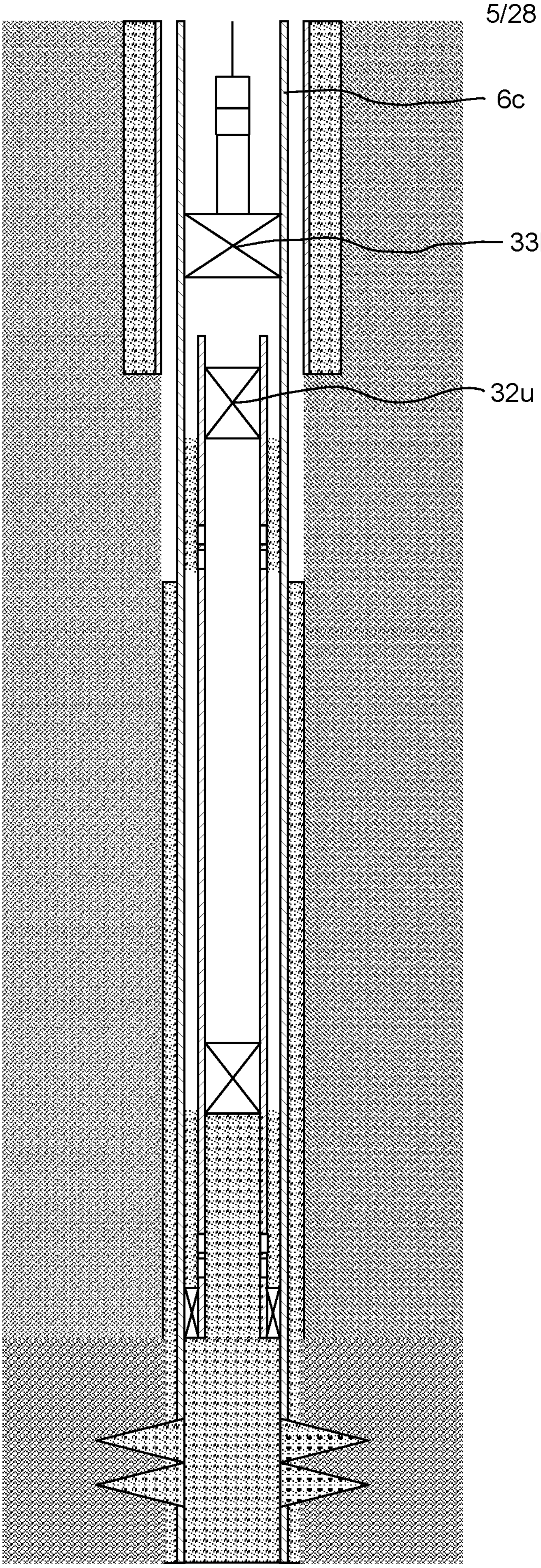


FIG. 2D

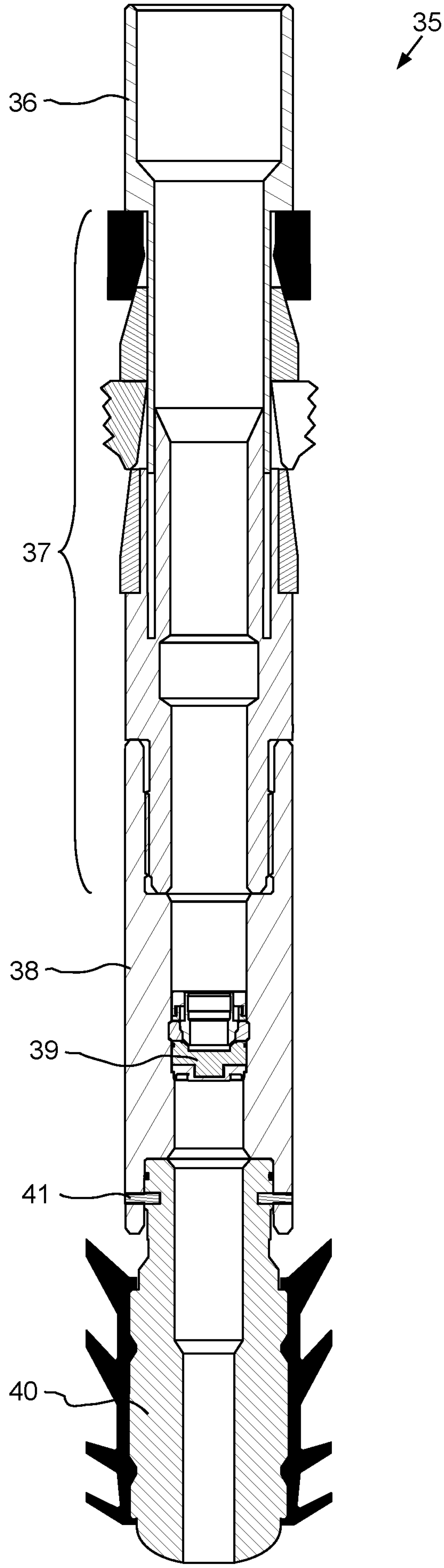


FIG. 3A

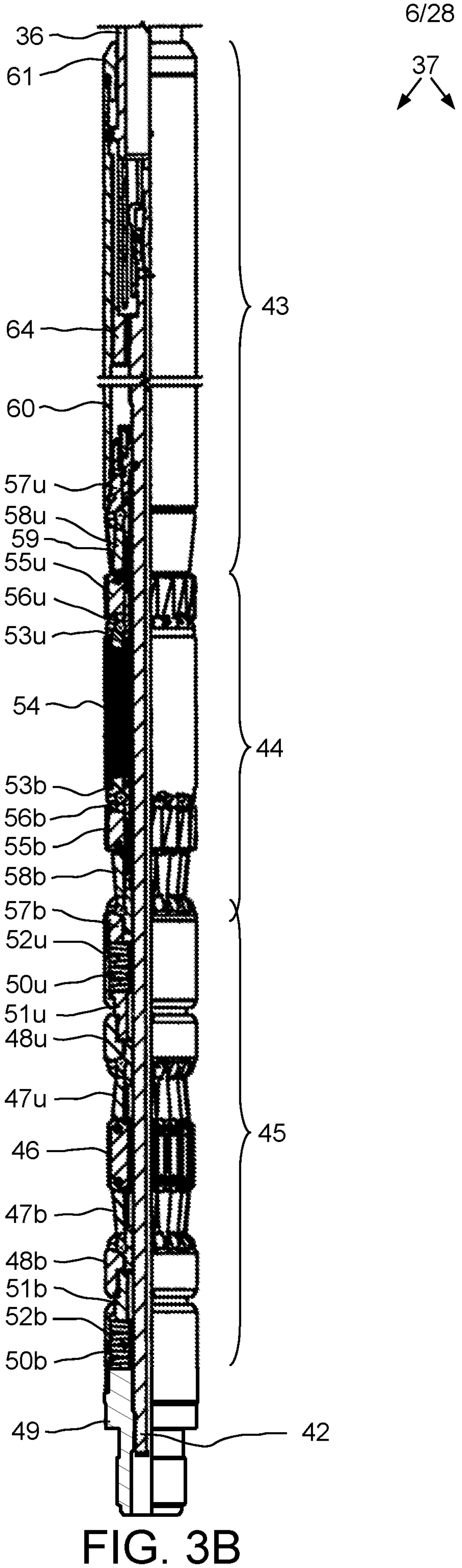

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FIG. 3B

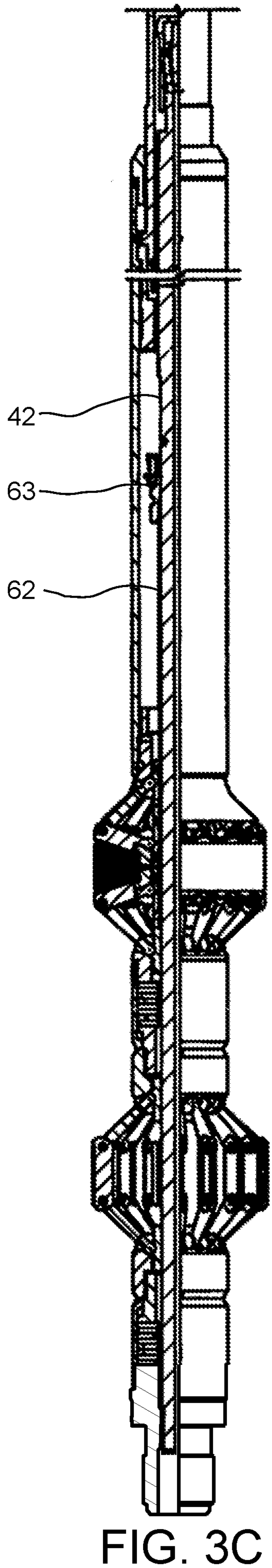
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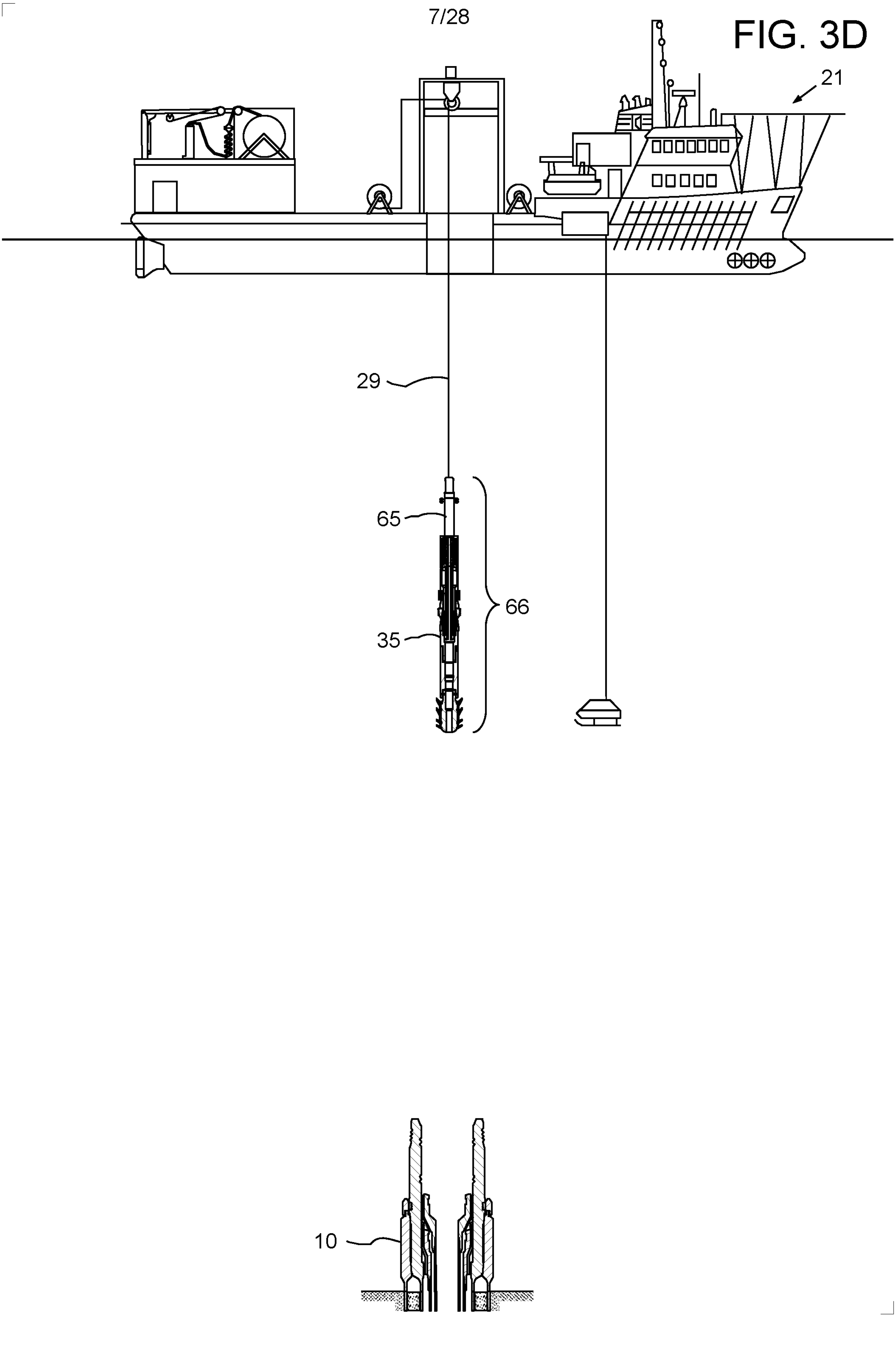
FIG. 3C

FIG. 3D



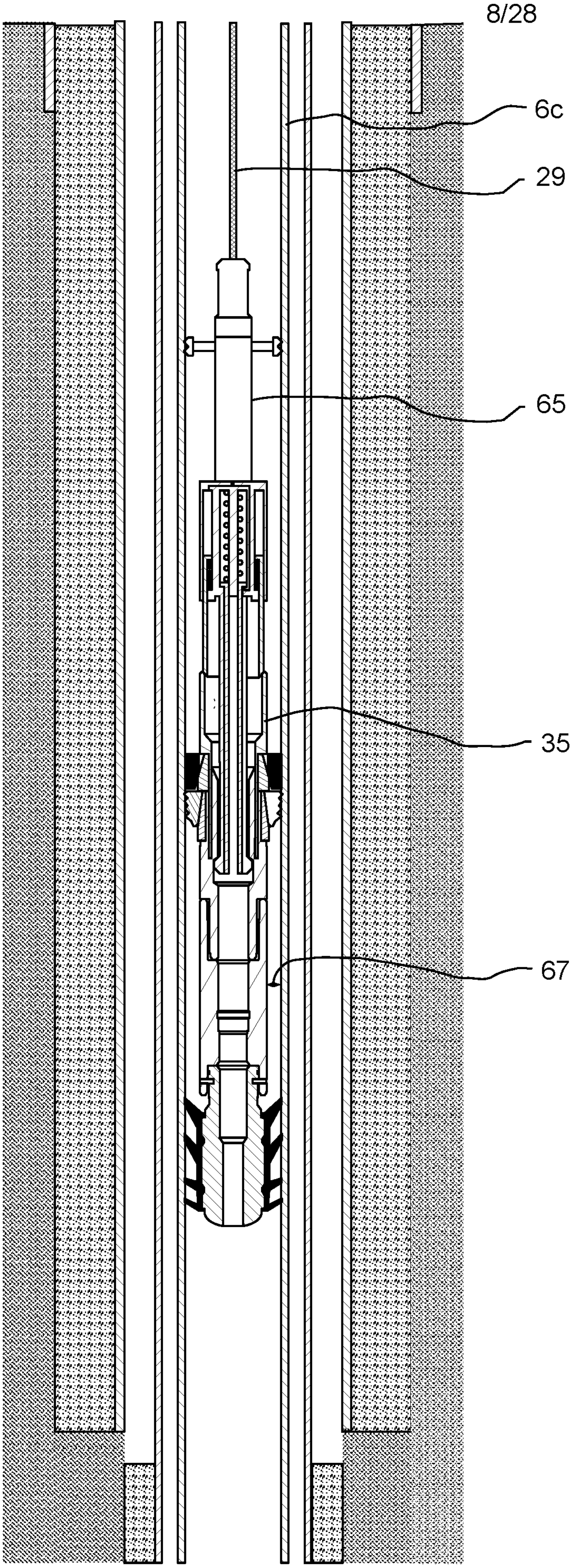


FIG. 3E

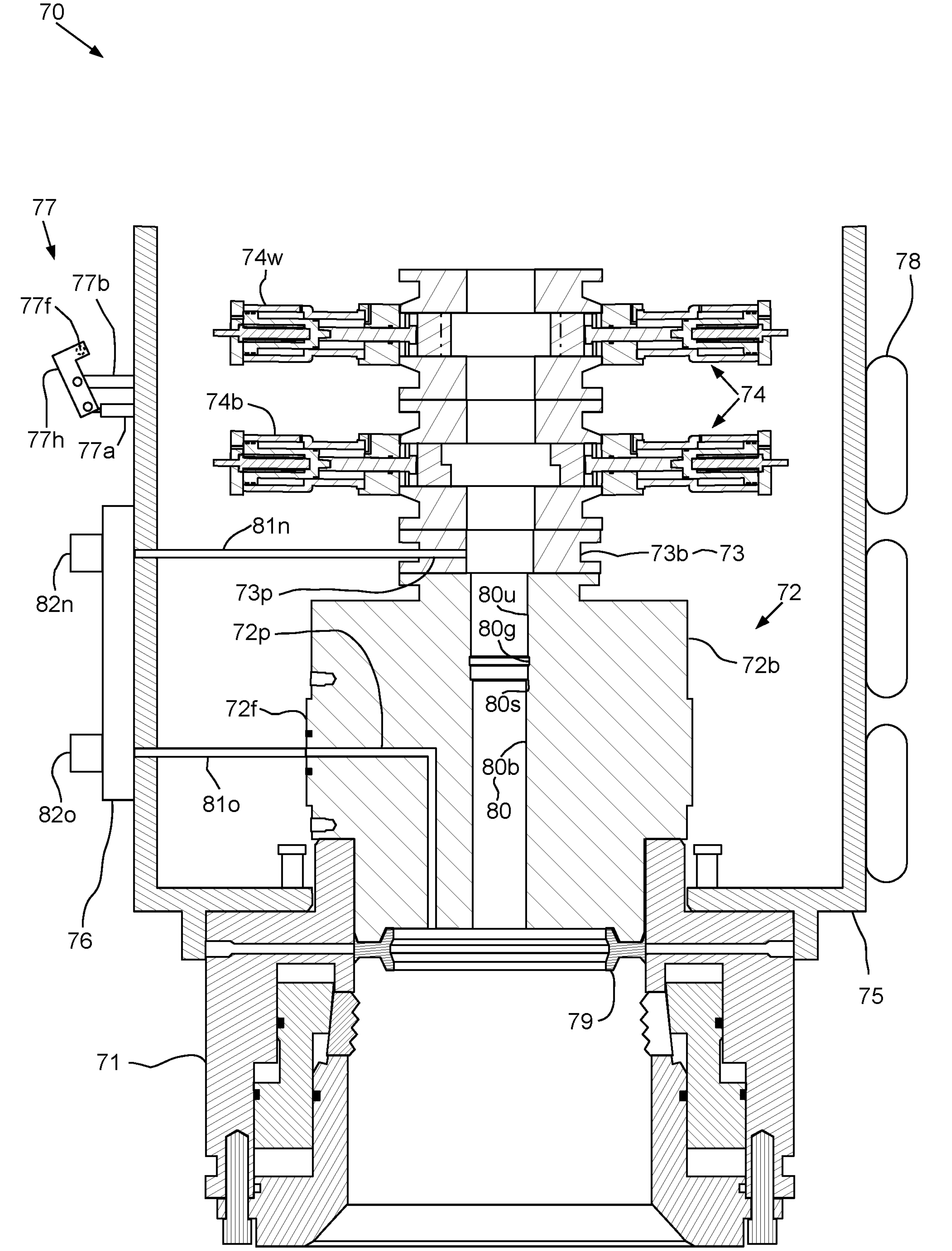

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FIG. 4A

FIG. 4B

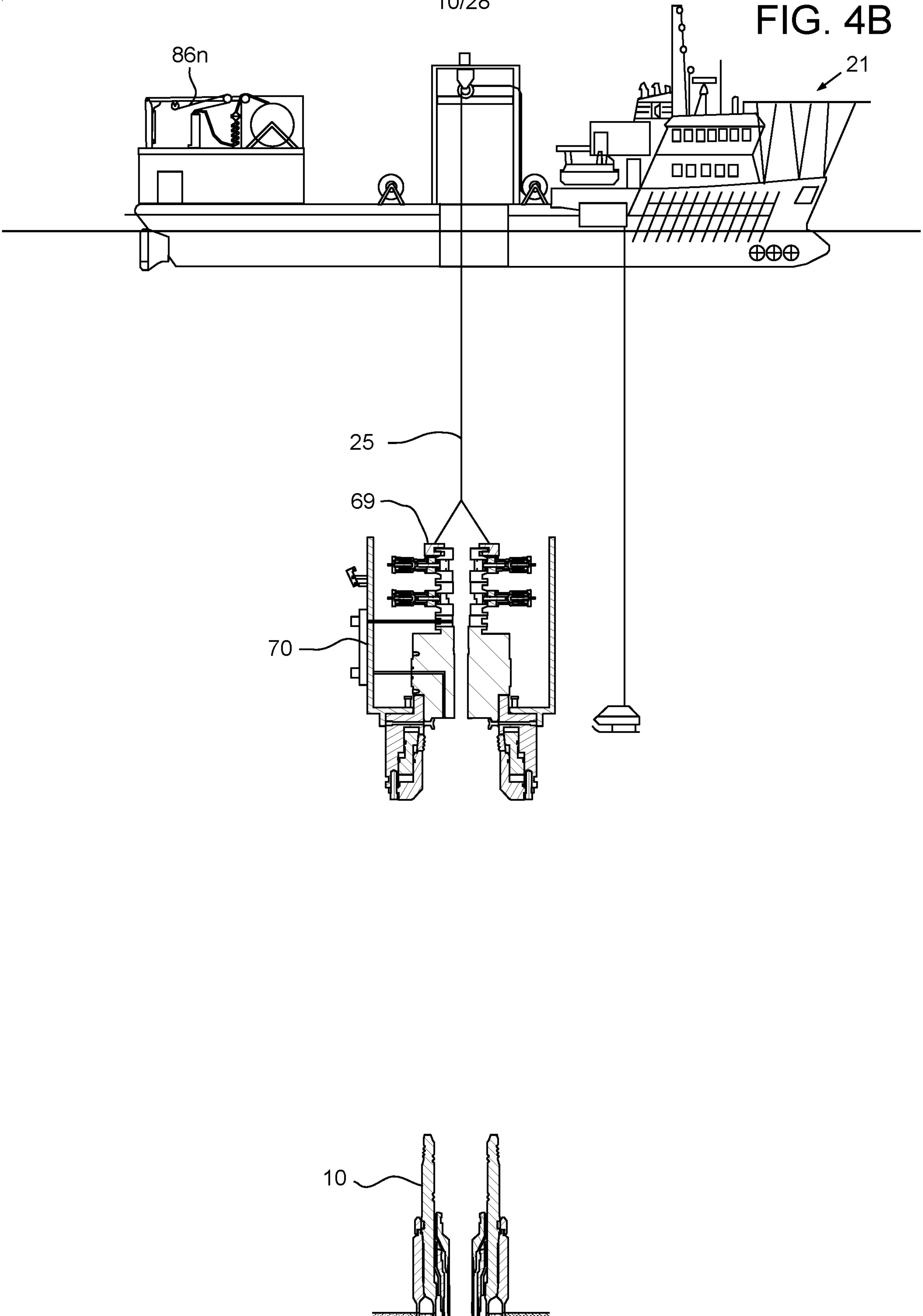
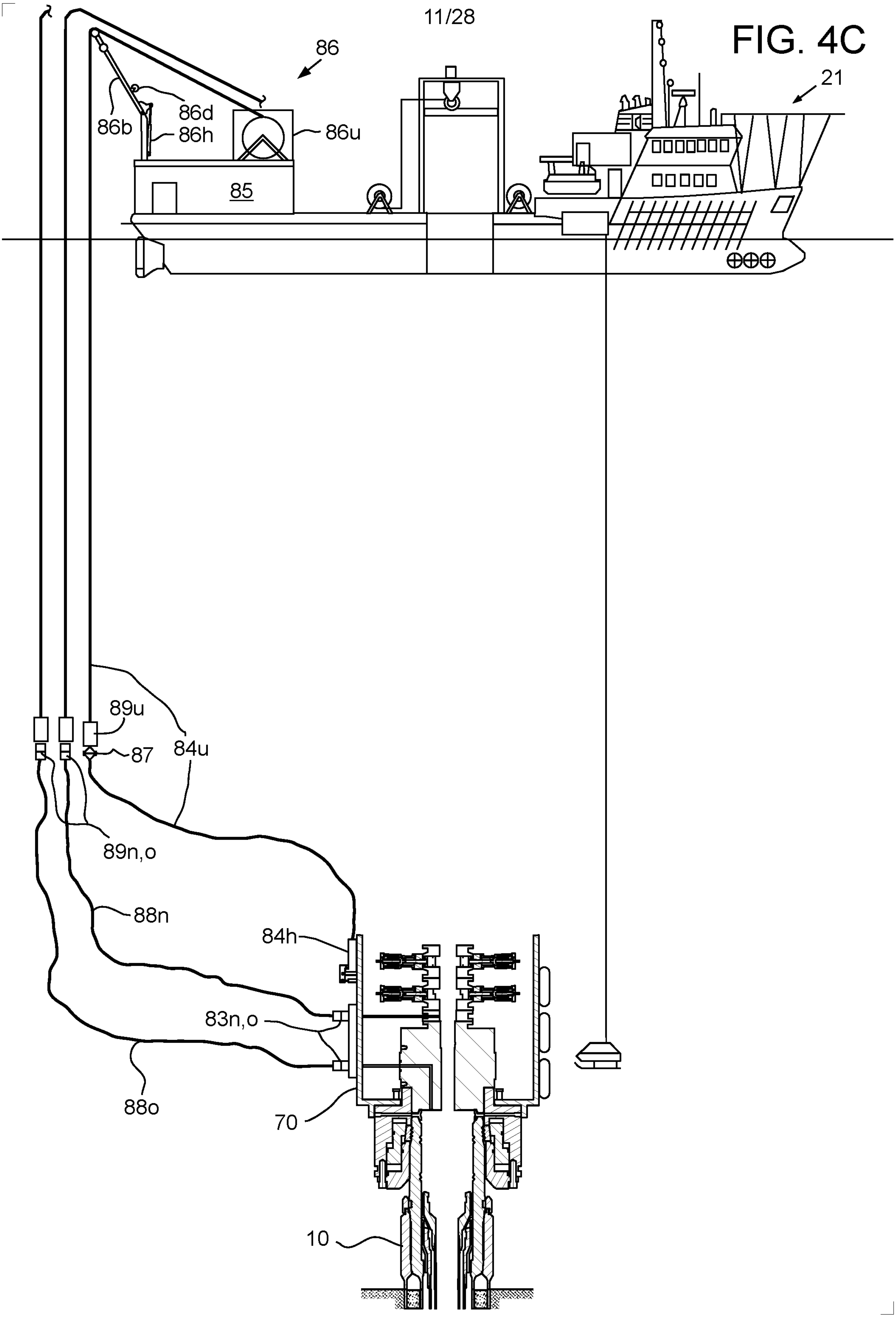


FIG. 4C



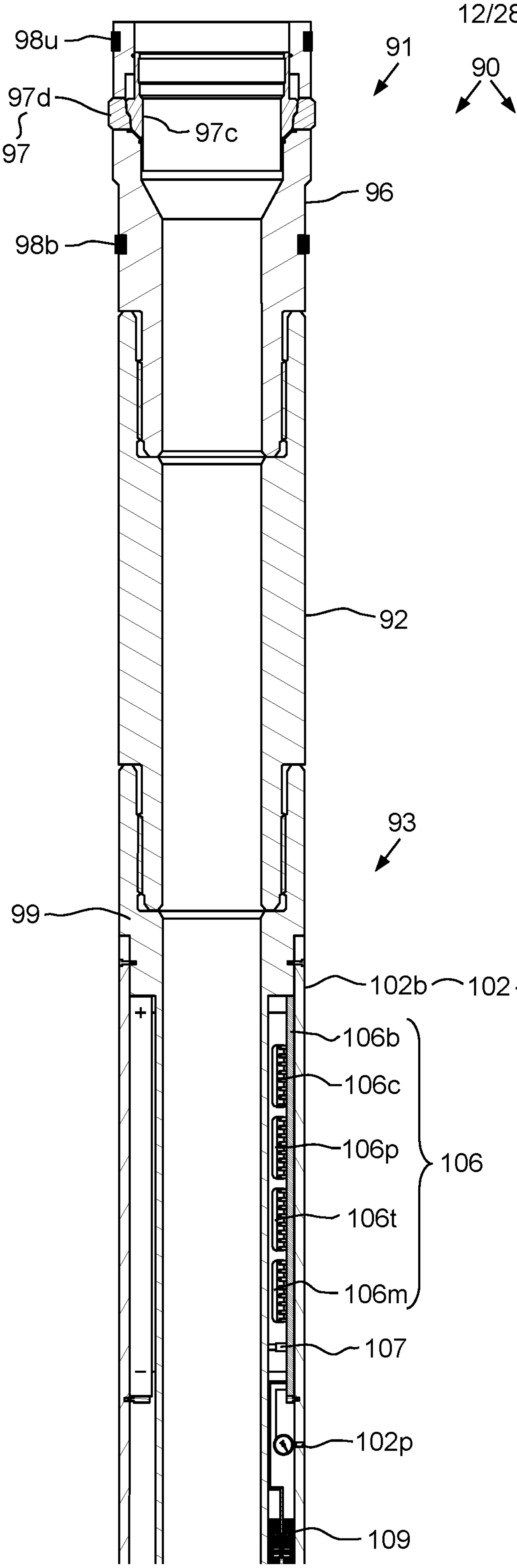

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FIG. 5A

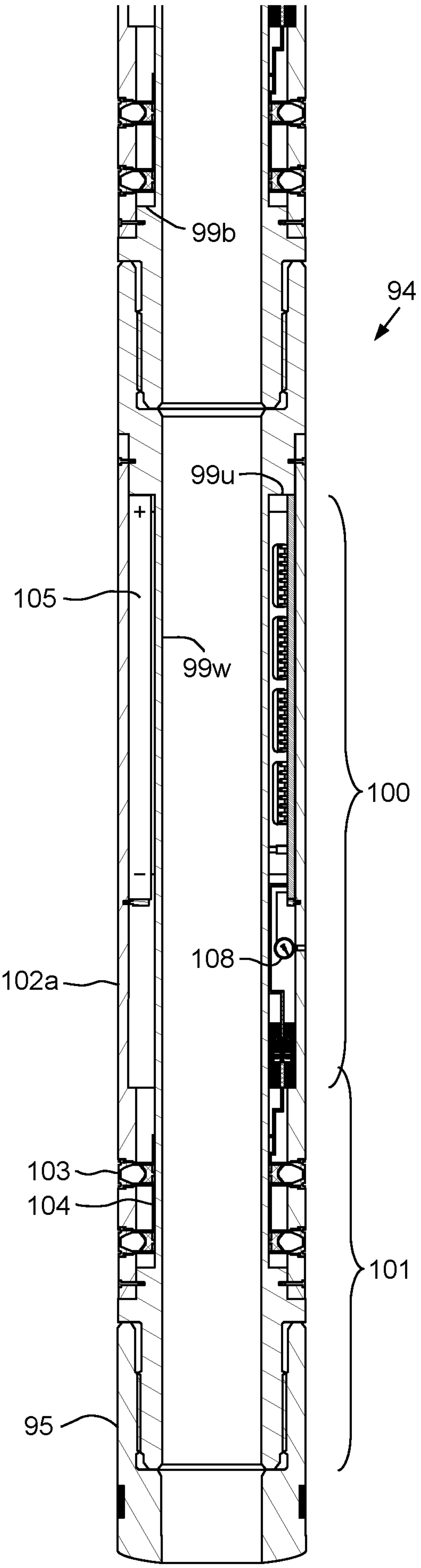
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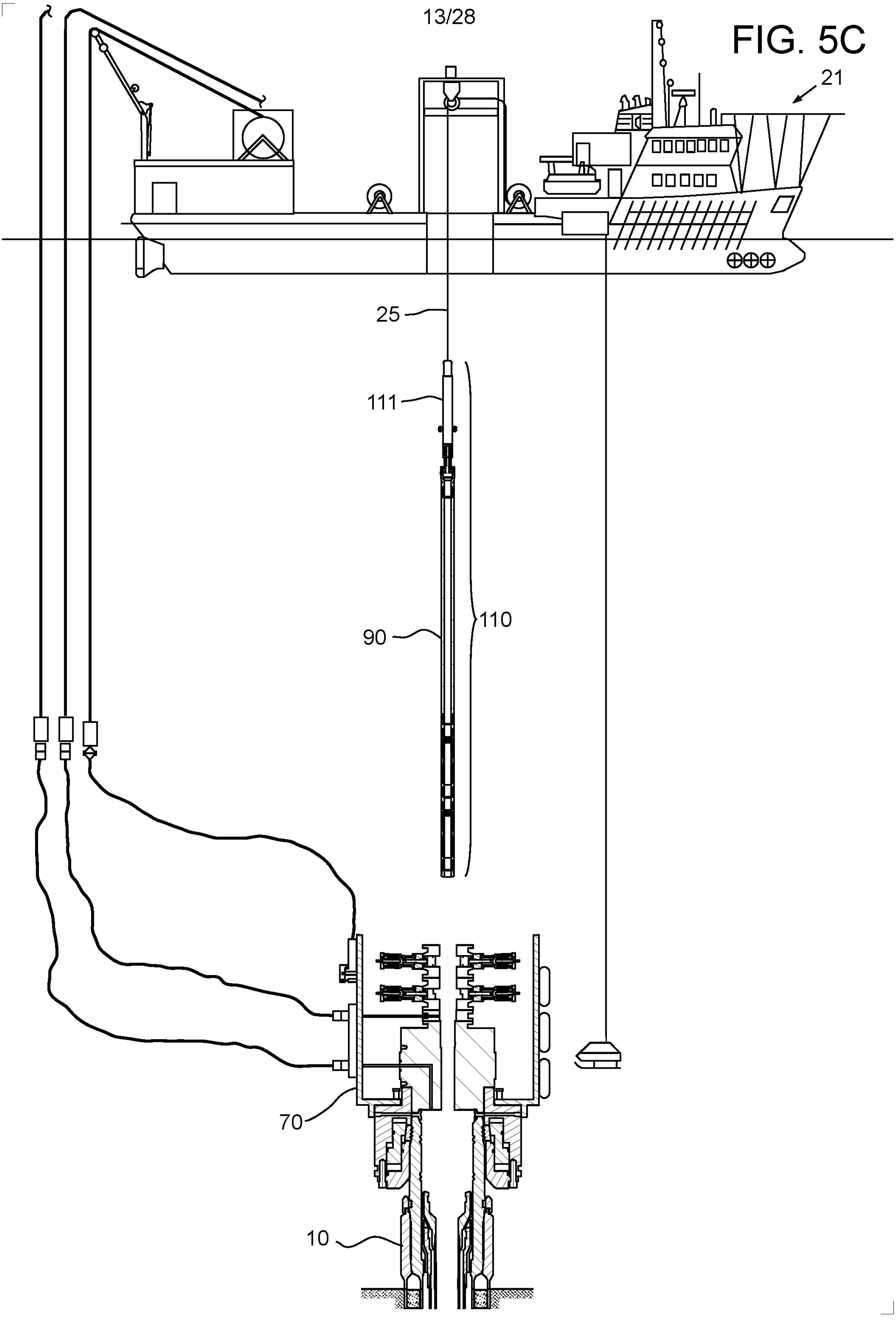
FIG. 5B

FIG. 5C



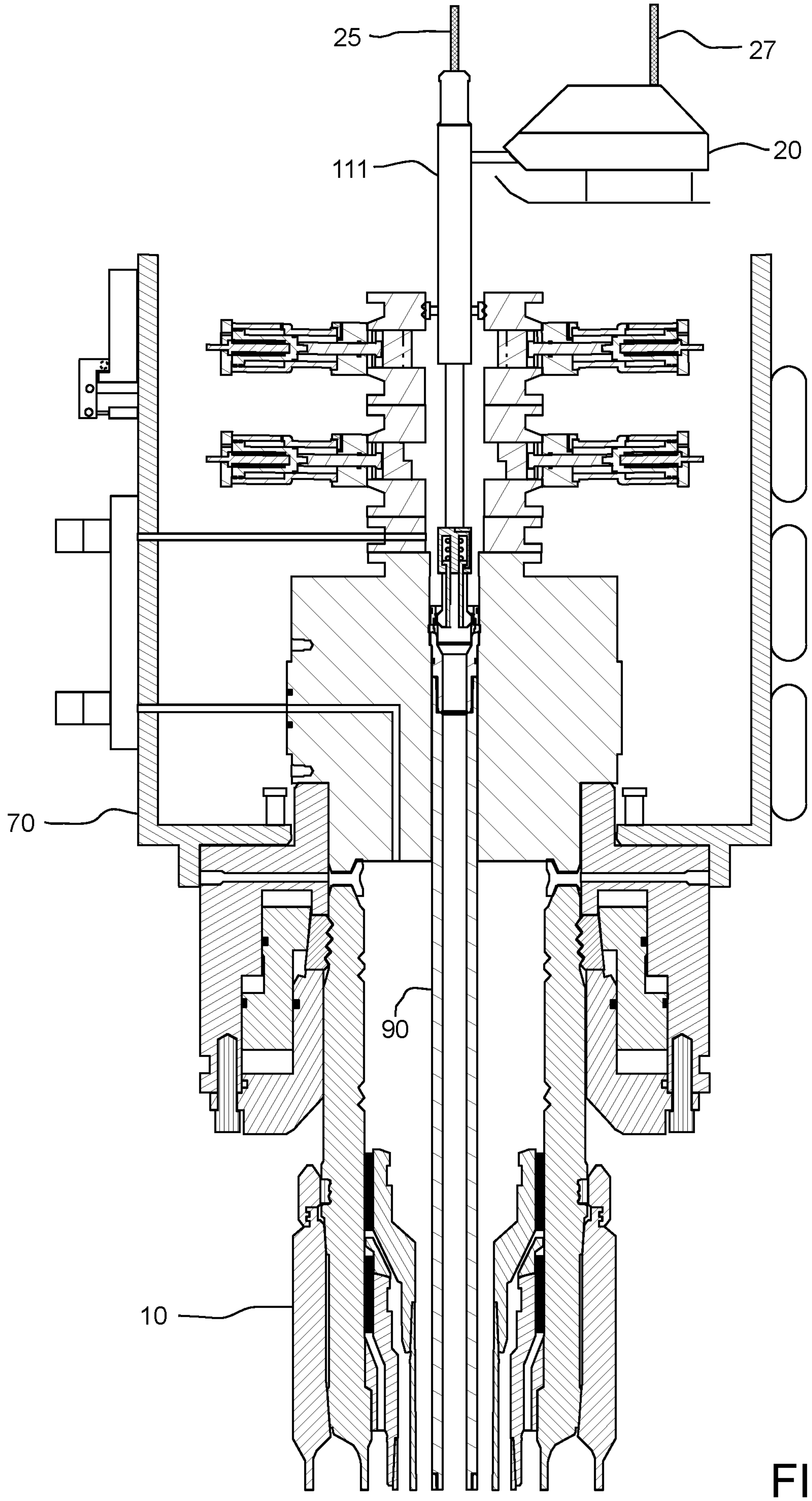


FIG. 5D

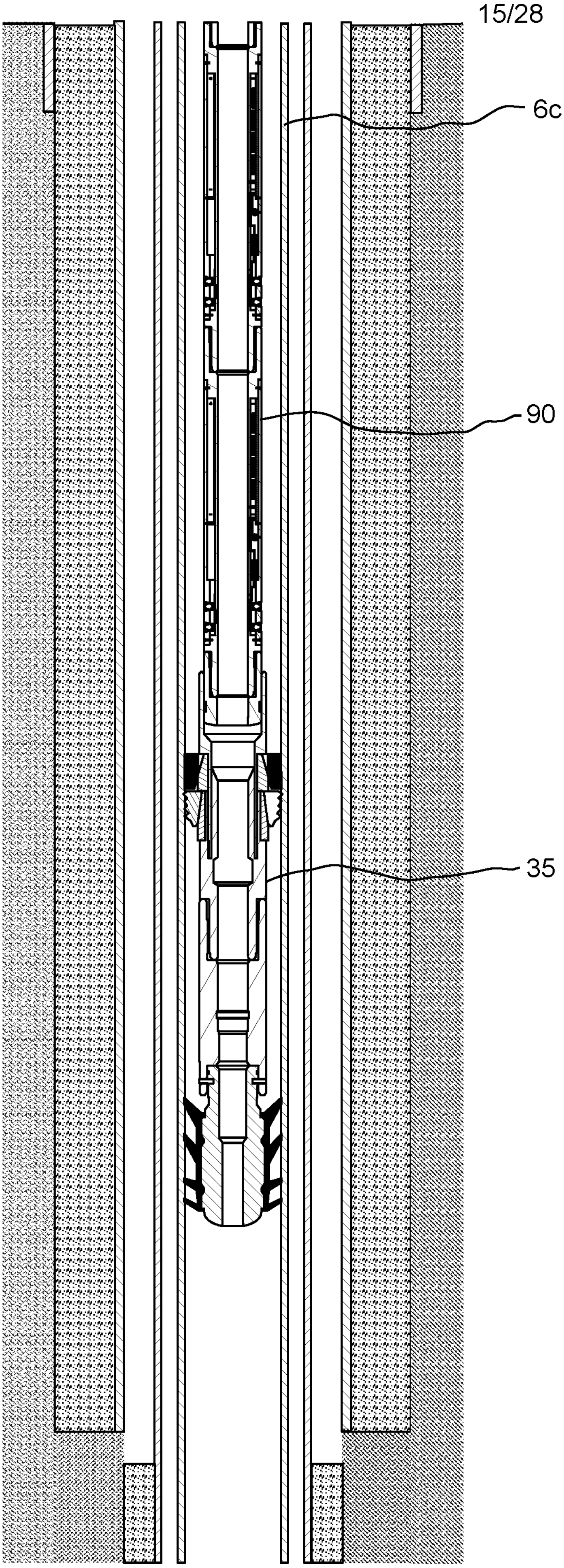
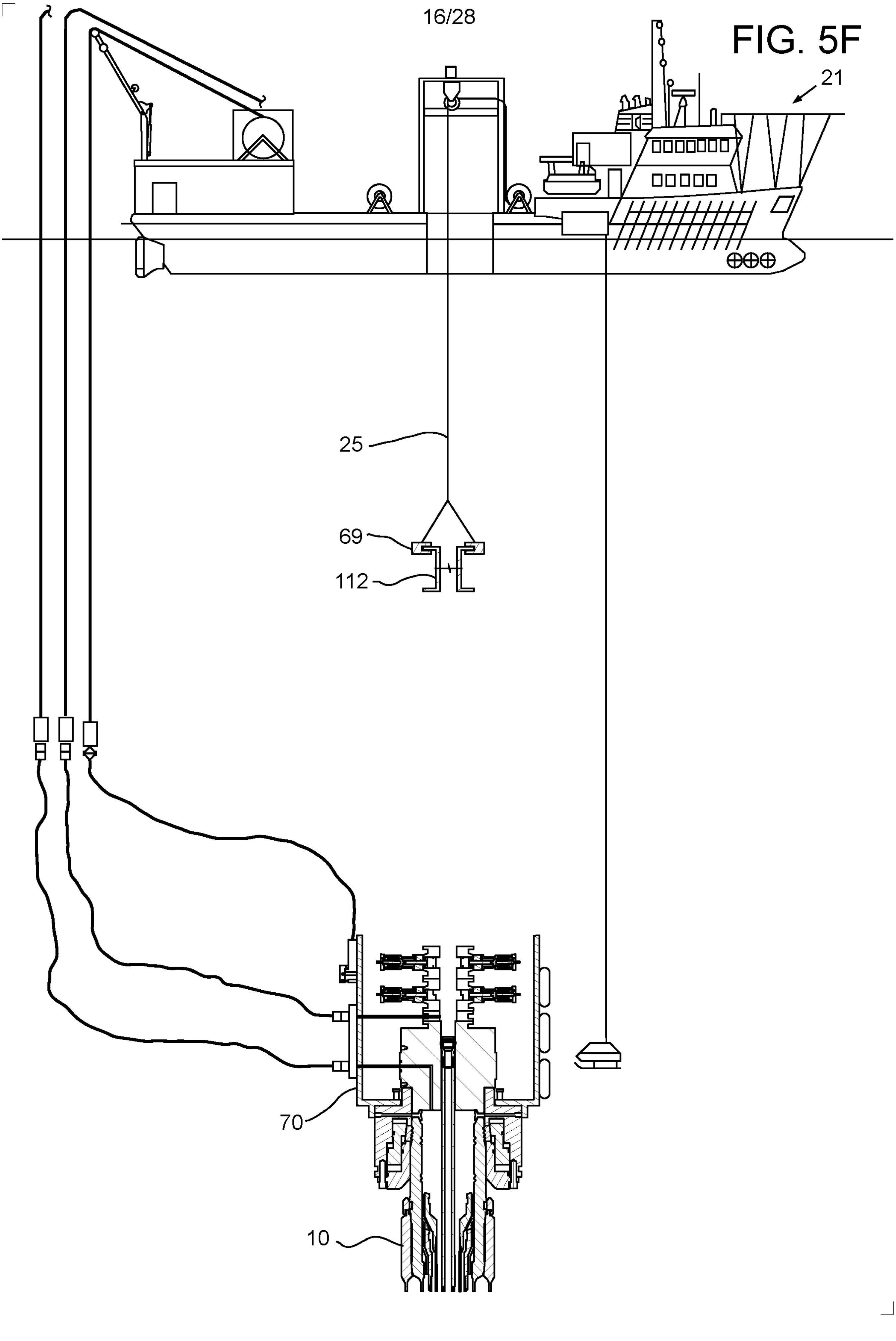


FIG. 5E

FIG. 5F



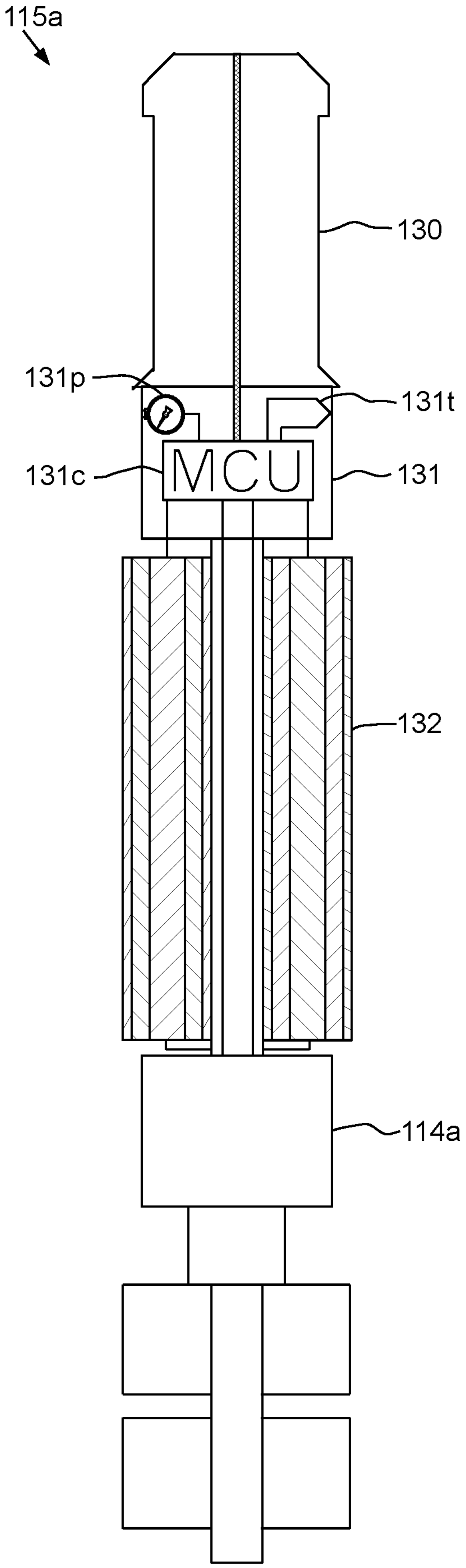


FIG. 6A

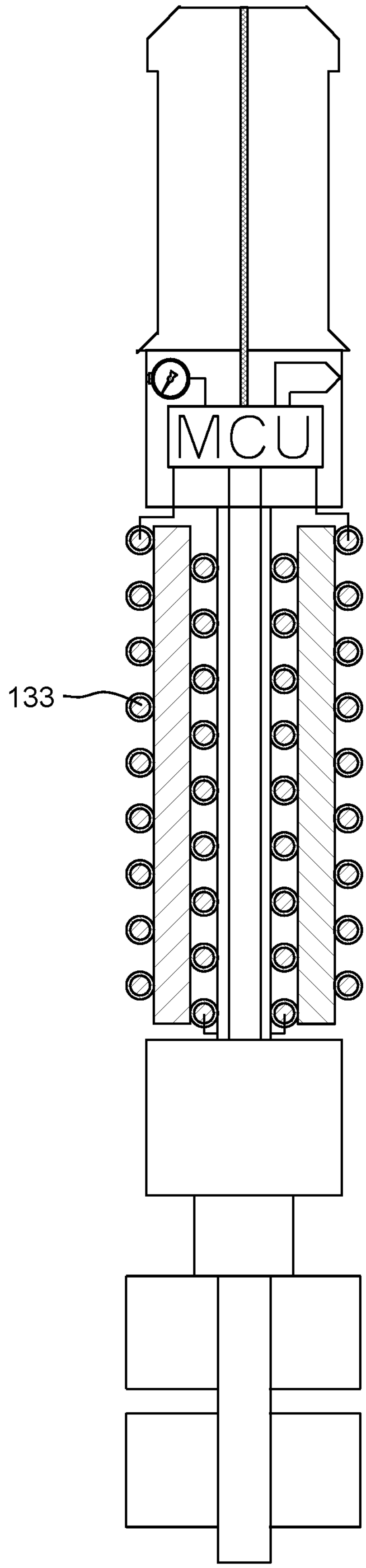
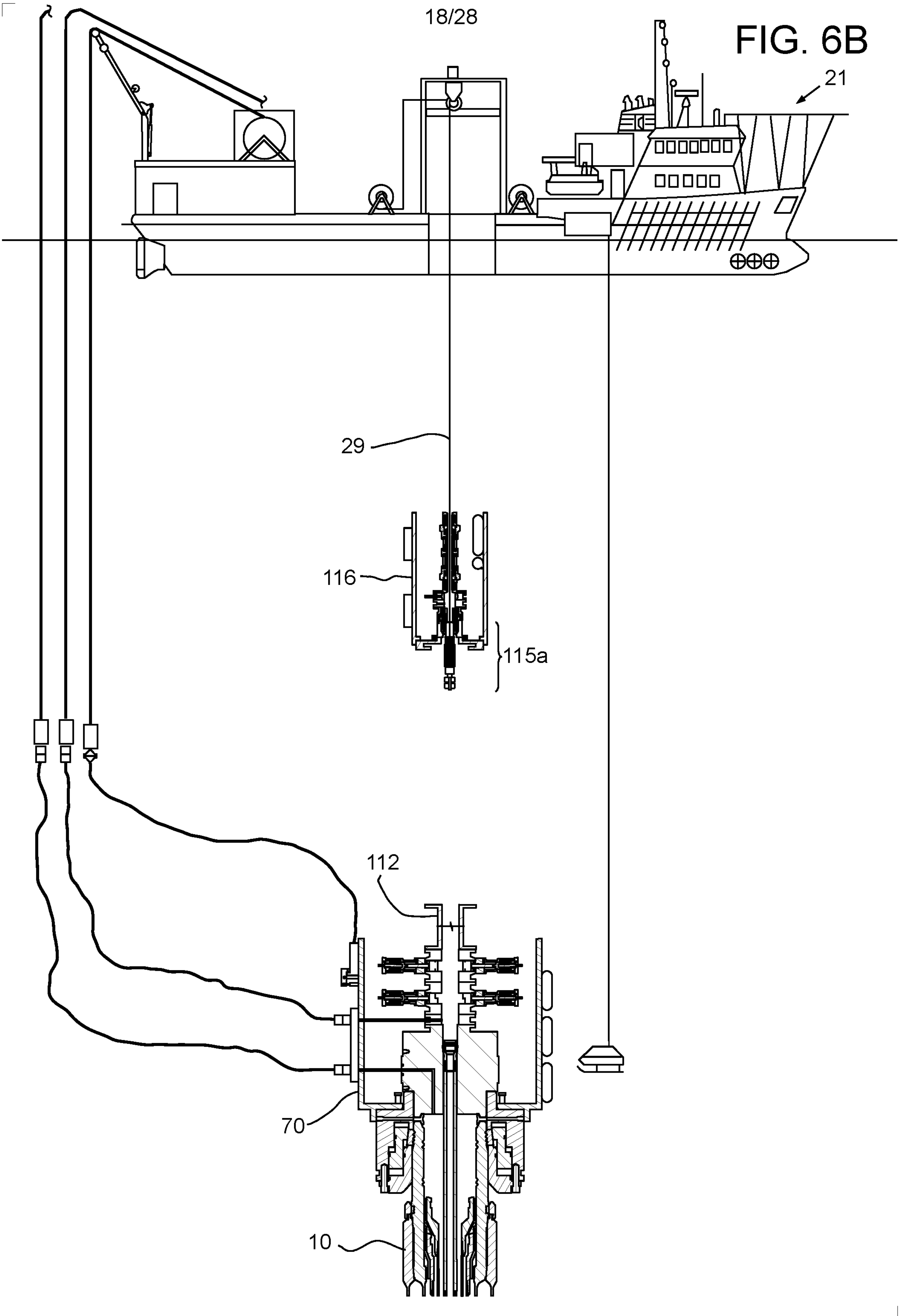


FIG. 9

FIG. 6B



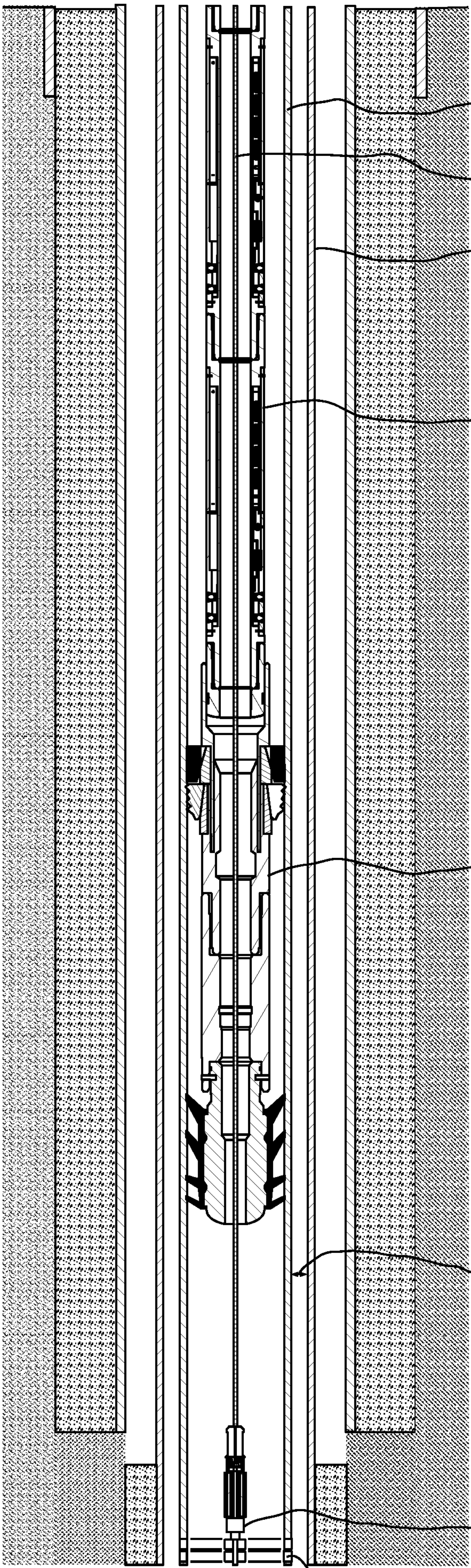


FIG. 6C

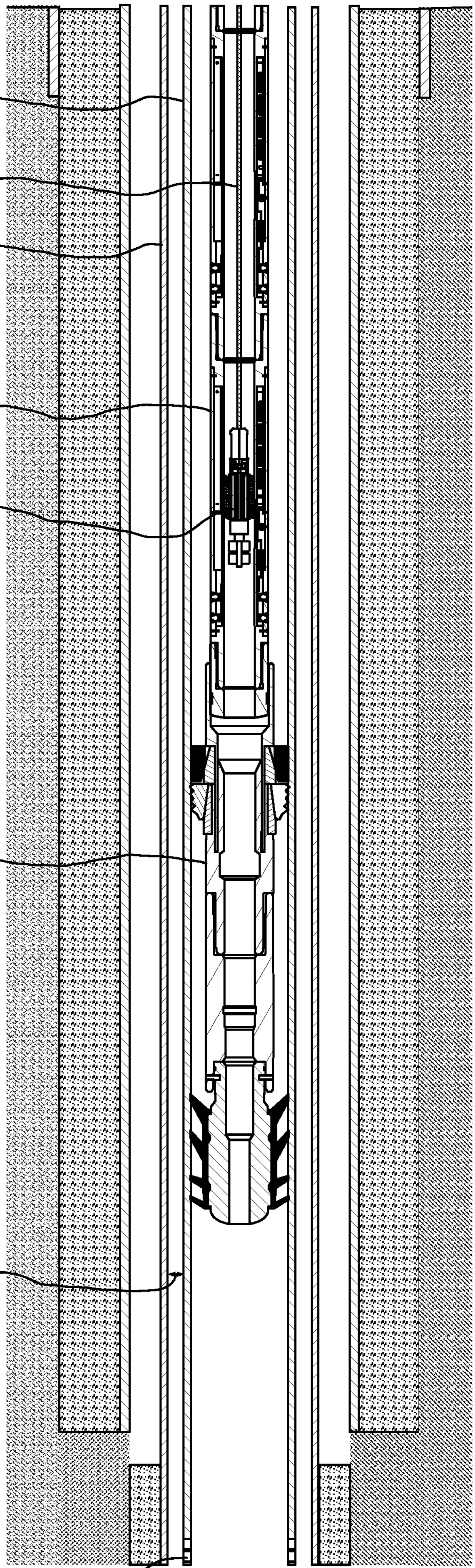


FIG. 6D

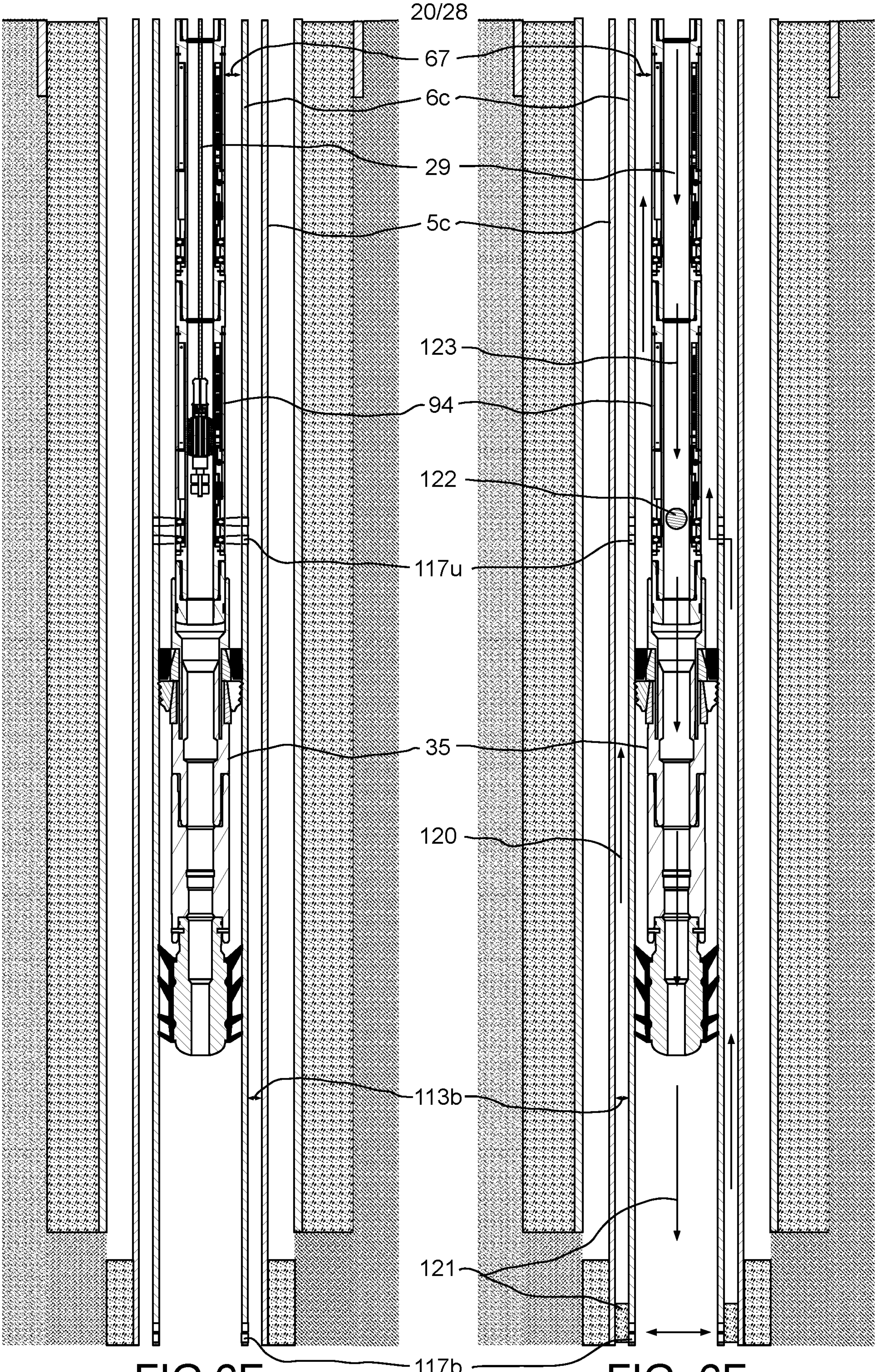


FIG.6E

FIG. 6F

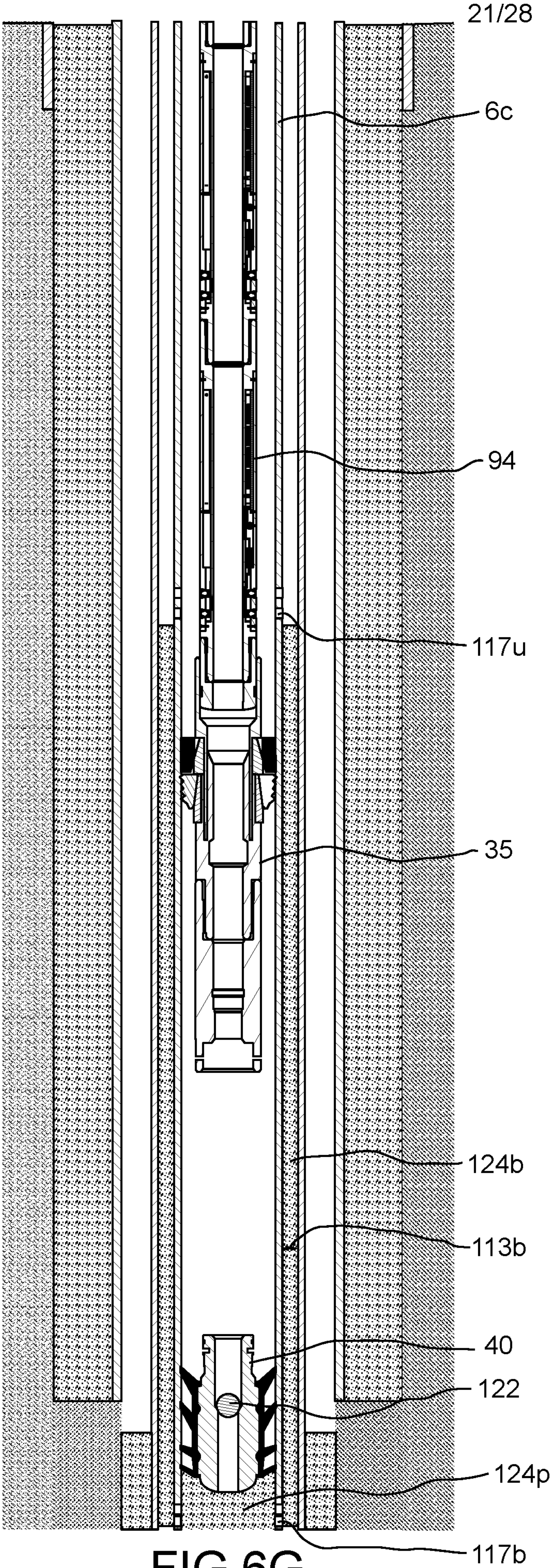
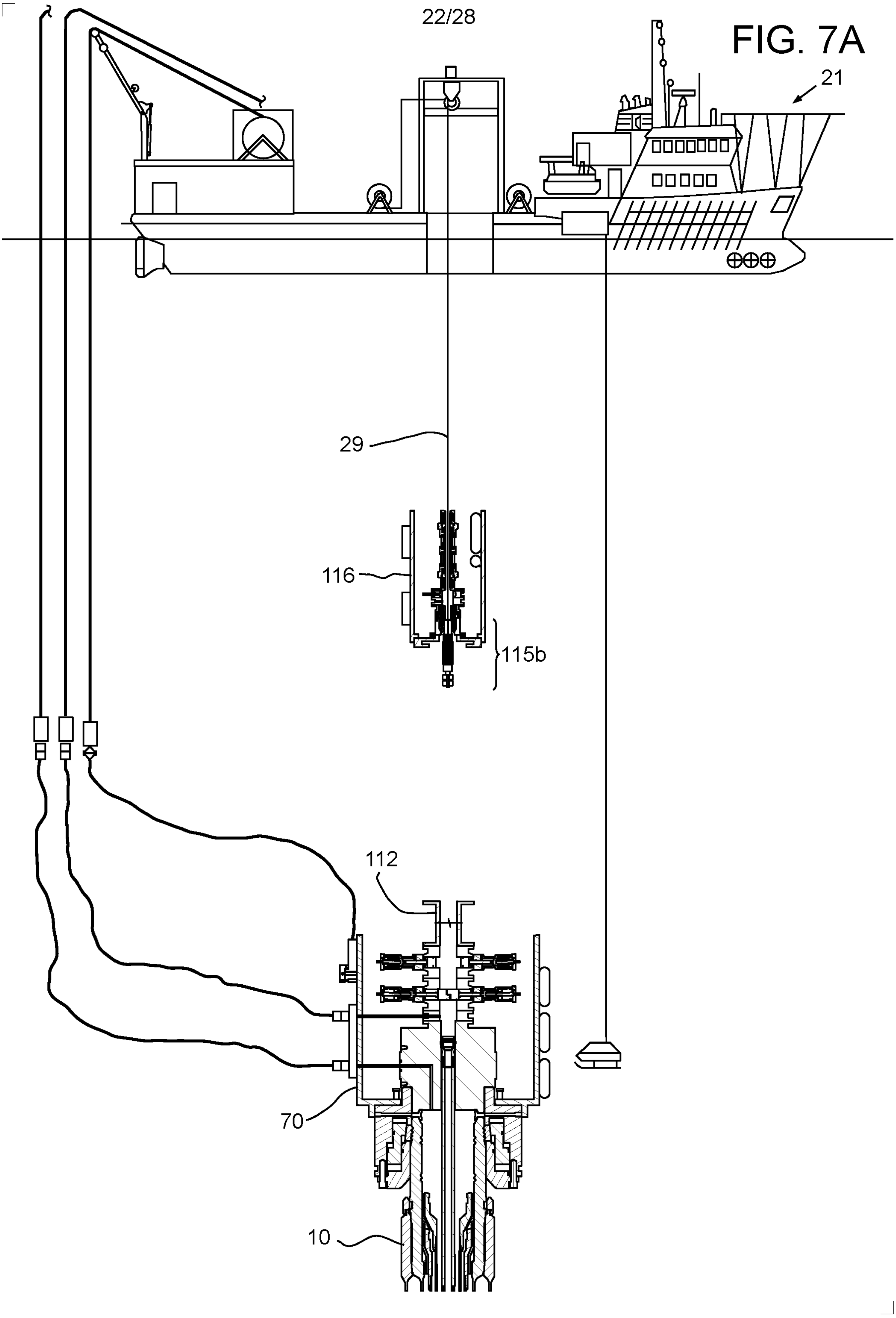


FIG.6G

FIG. 7A



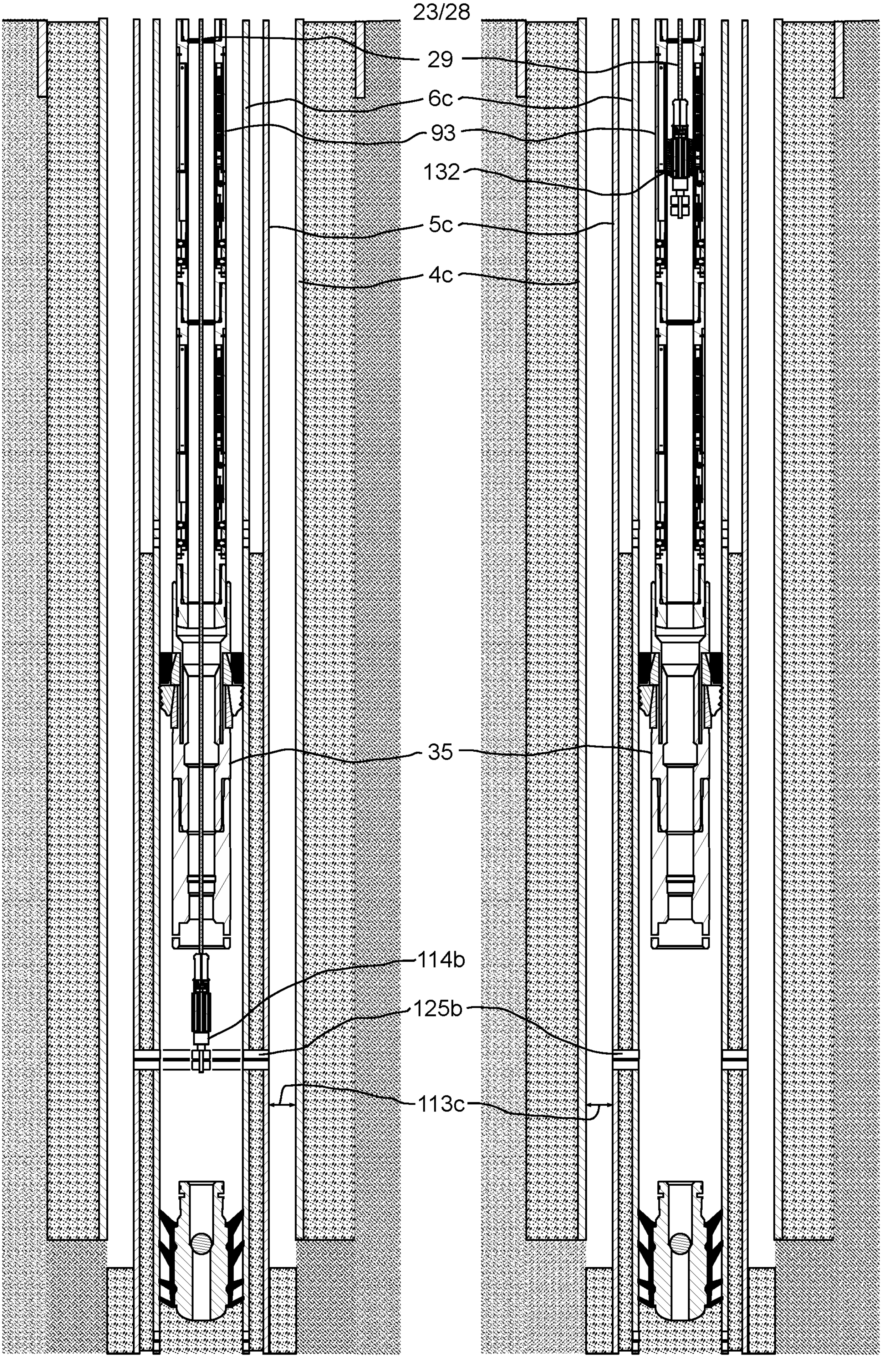


FIG.7B

FIG. 7C

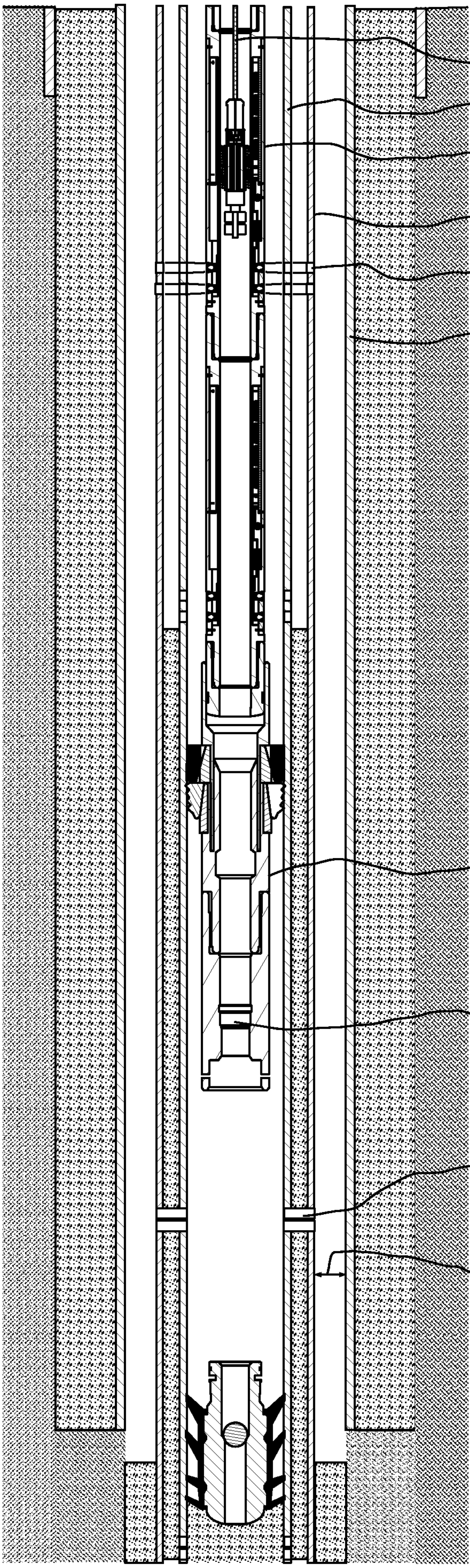


FIG.7D

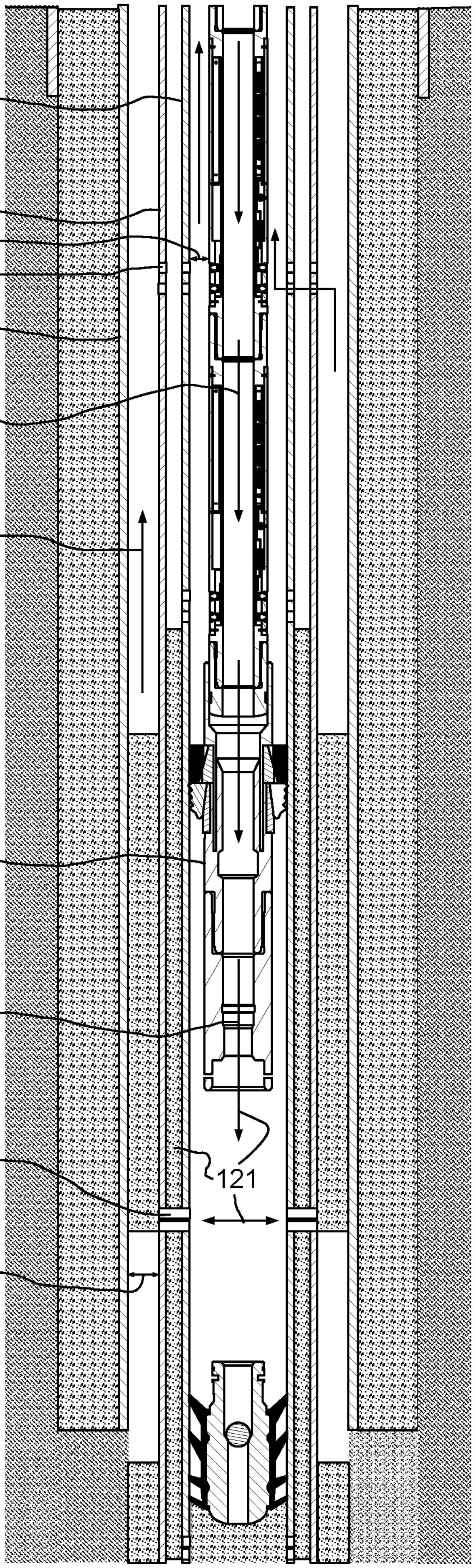
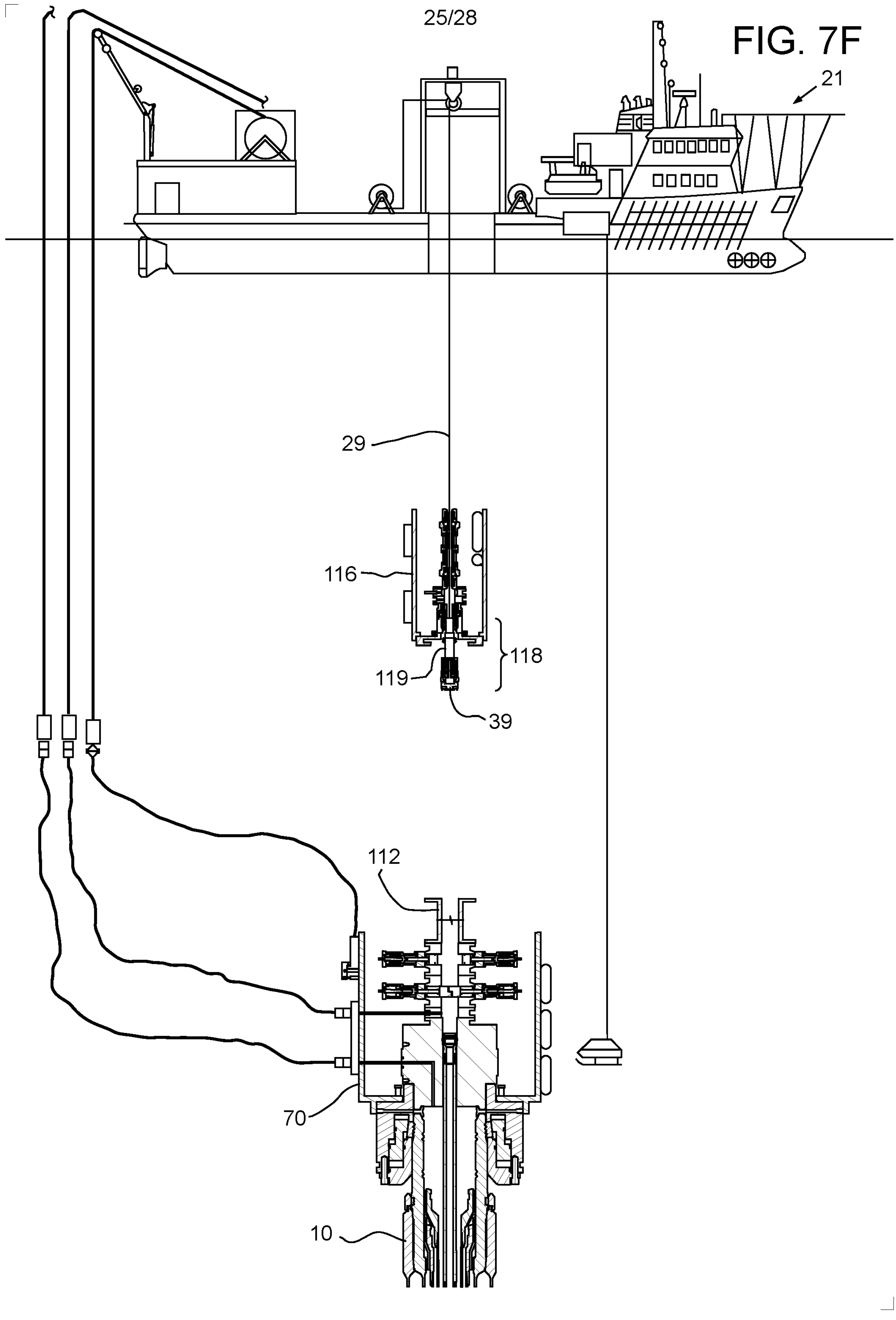


FIG. 7E

FIG. 7F



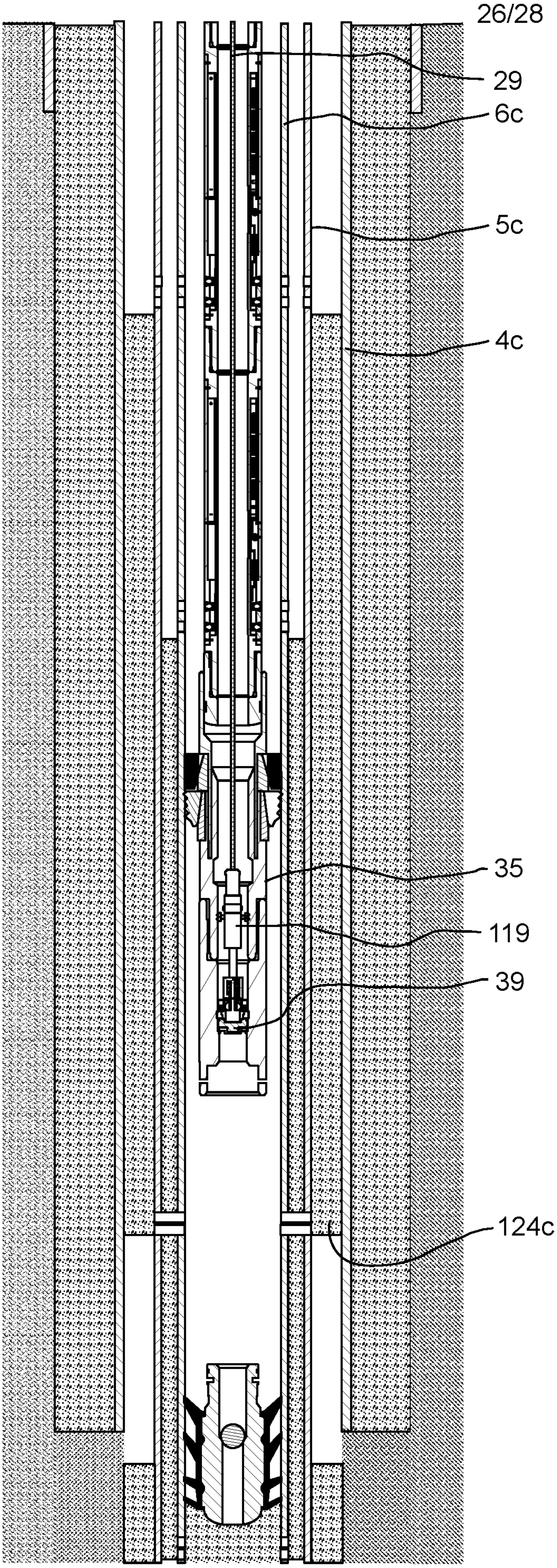
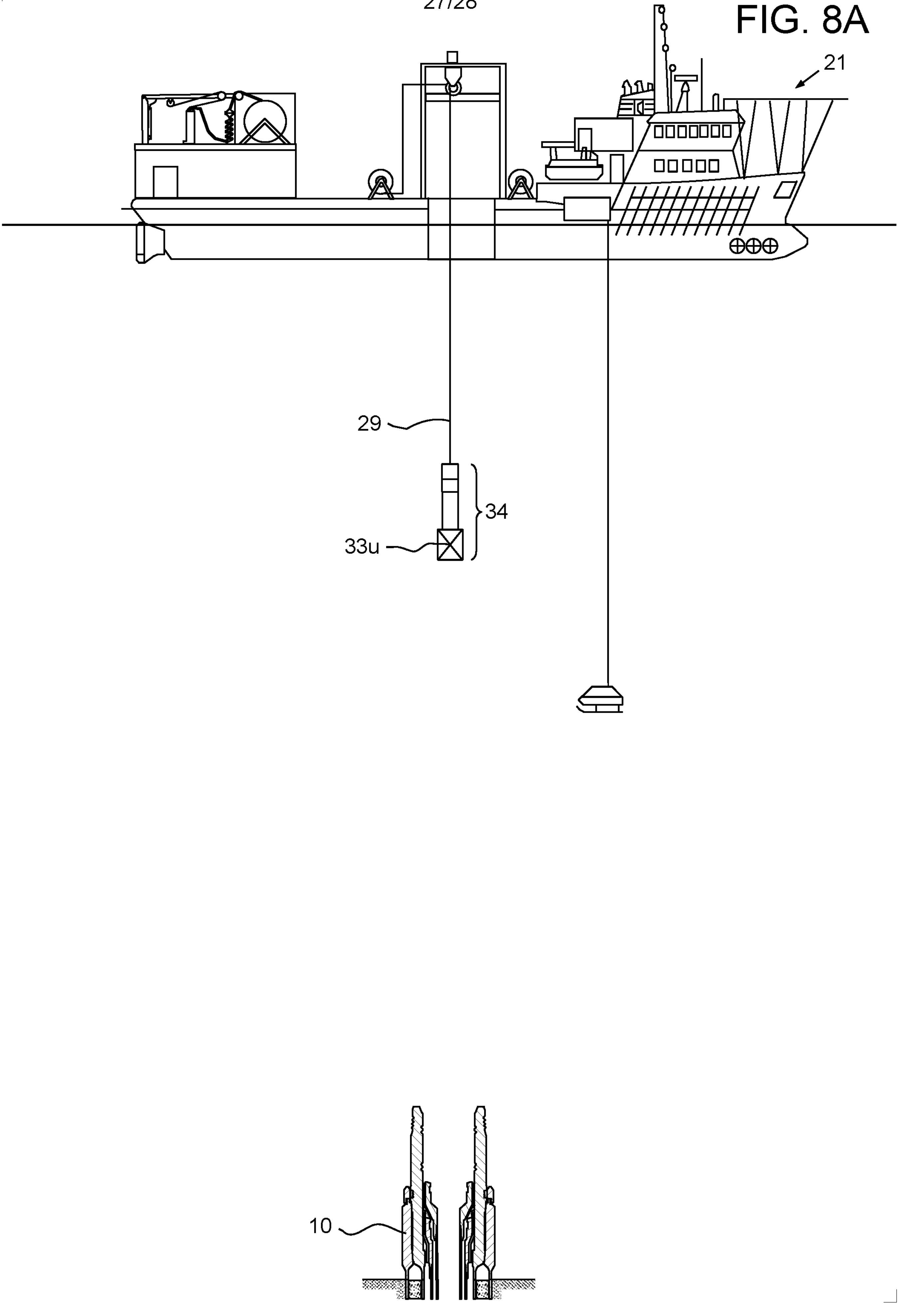


FIG.7G

FIG. 8A



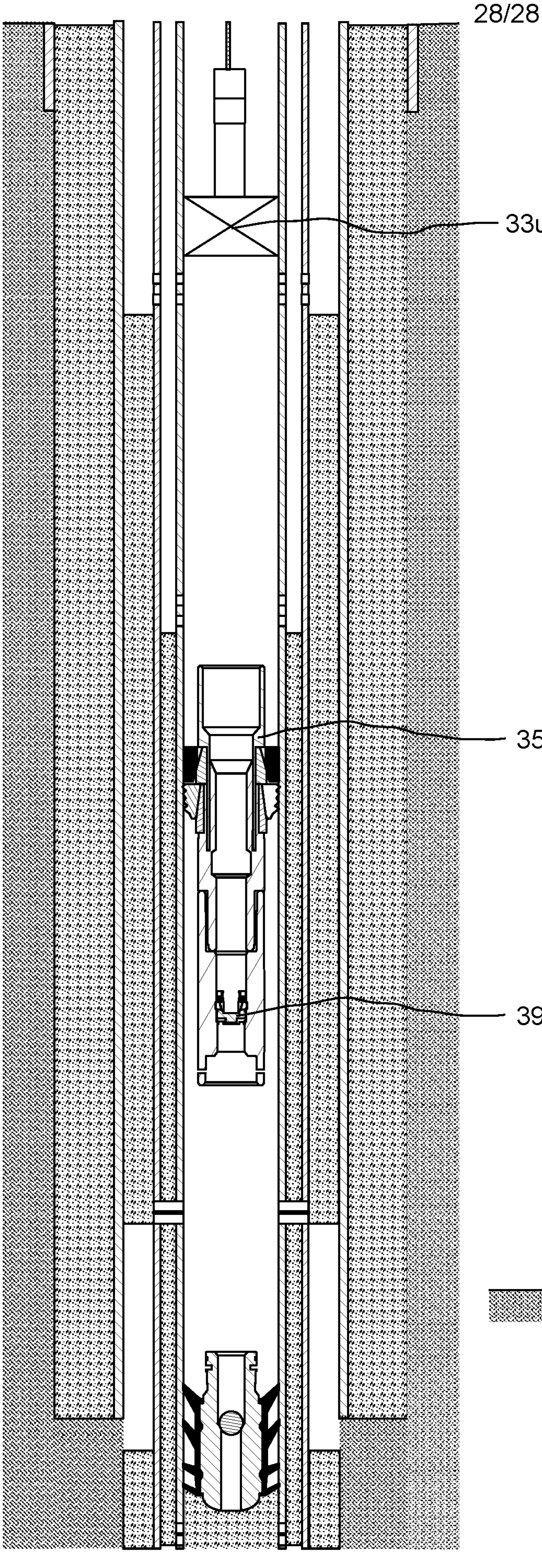


FIG. 8B

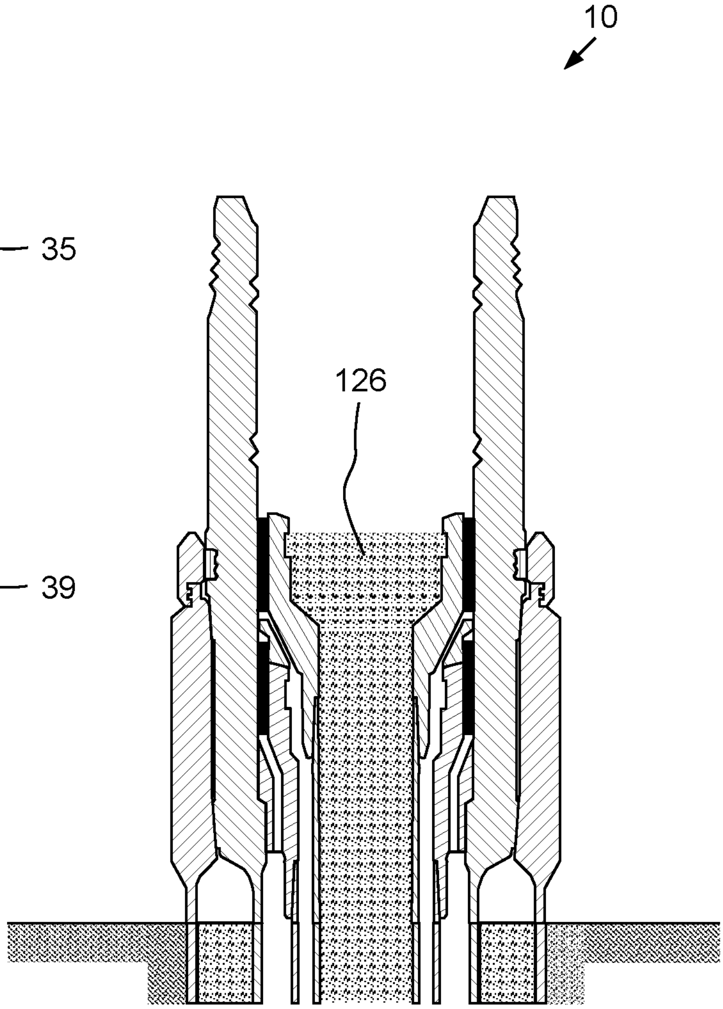


FIG.8C

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2015/064889

A. CLASSIFICATION OF SUBJECT MATTER
INV. E21B29/12 E21B33/035 E21B33/13 E21B36/04 E21B43/1185
ADD.

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

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B F24D F24C

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 practicable, search terms used)

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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Y A	US 2013/269948 A1 (HOFFMAN COREY EUGENE [US] ET AL) 17 October 2013 (2013-10-17) paragraphs [0013], [0036], [0037], [0056] - [0068], [0091] - [0098]; claims; figures -----	4-20 1
X A	EP 2 006 486 A2 (HALLIBURTON ENERGY SERV INC [US]) 24 December 2008 (2008-12-24) paragraphs [0006] - [0008], [0013], [0027] - [0030], [0049] - [0051], [0060] - [0064]; claims; figures -----	1-3 5-8, 18-20
	-/--	

[X] Further documents are listed in the continuation of Box C.

[X] See patent family annex.

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Date of the actual completion of the international search	Date of mailing of the international search report
20 April 2016	28/04/2016

Name and mailing address of the ISA/	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Fax: (+31-70) 340-3016	Henkes, Roeland

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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 2014/338439 A1 (LIGNEUL PATRICE [FR] ET AL) 20 November 2014 (2014-11-20) paragraphs [0004], [0024] - [0041]; figures -----	1,18
A	US 2011/209871 A1 (LE CAM VAN [US] ET AL) 1 September 2011 (2011-09-01) paragraphs [0027] - [0062]; figures -----	1,18
A	WO 96/24752 A2 (BAKER HUGHES INC [US]) 15 August 1996 (1996-08-15) page 59, line 9 - page 63, line 12 -----	1,18

1

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No
PCT/US2015/064889

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