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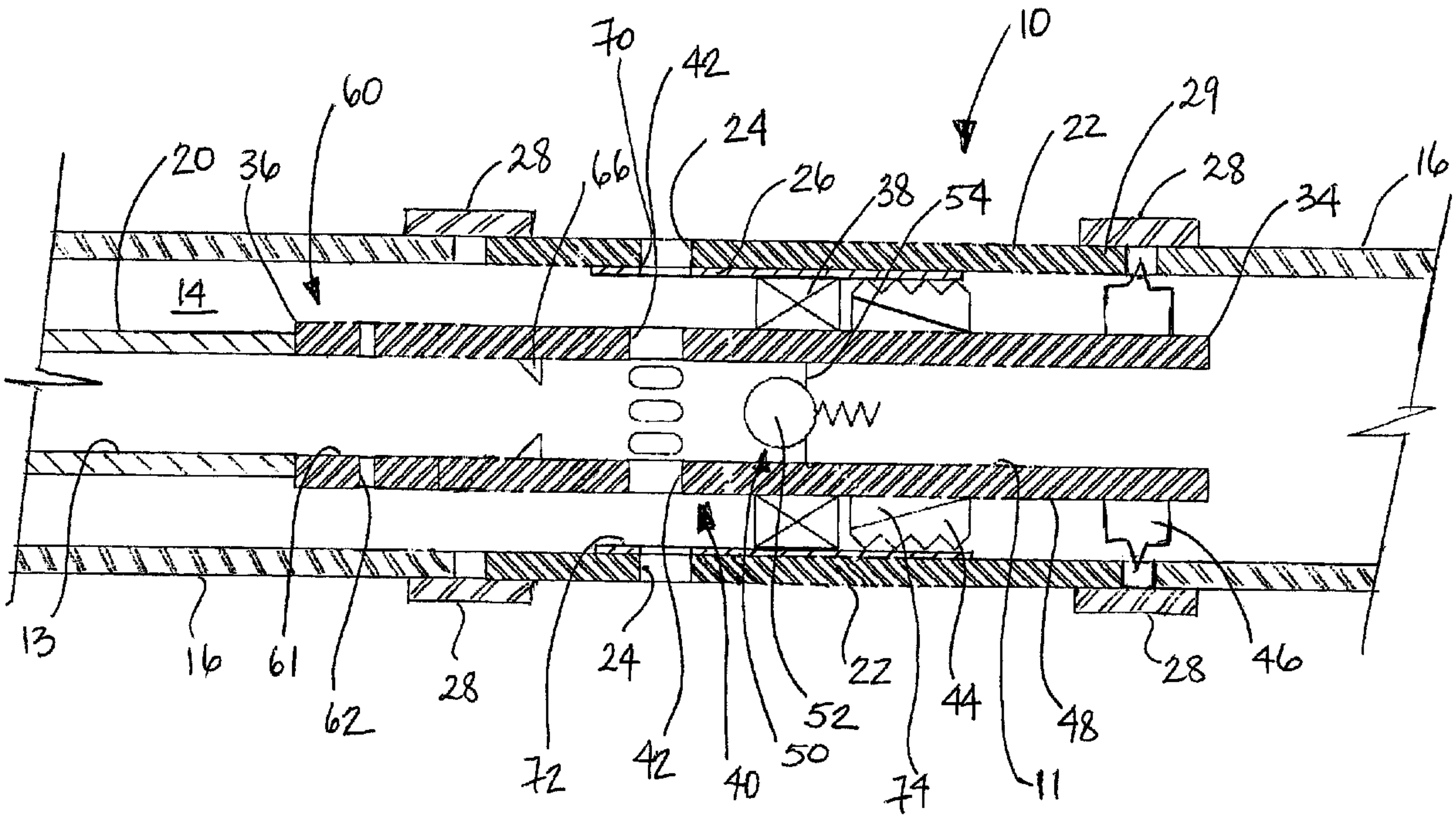

(57) Abrégé/Abstract:
A bottomhole assembly deployable into a wellbore on coiled tubing and which has at least a casing collar locator, a fluid-delivery apparatus for delivery treatment fluid and a sealing element, typically a packer positioned therebetween, permits delivery of treatment fluid to a plurality of ports formed in casing through either the annulus between the BHA and the casing, through the coiled tubing or through both. Variable volumes of treatment fluid can be delivered as a result of the different volumes of the coiled tubing and the annulus or the combined volume of both. Sleeves used to cover the fracturing ports in the casing to permit selective opening and fracturing therethrough are made shorter than prior art sleeves as a result of the particular arrangement of the BHA and engagement of collars in the casing with the casing collar locator.

ABSTRACT

A bottomhole assembly deployable into a wellbore on coiled tubing and which has at least a casing collar locator, a fluid-delivery apparatus for delivery treatment fluid and a sealing element, typically a packer positioned therebetween, permits delivery of treatment fluid to a plurality of ports formed in casing through either the annulus between the BHA and the casing, through the coiled tubing or through both. Variable volumes of treatment fluid can be delivered as a result of the different volumes of the coiled tubing and the annulus or the combined volume of both. Sleeves used to cover the fracturing ports in the casing to permit selective opening and fracturing therethrough are made shorter than prior art sleeves as a result of the particular arrangement of the BHA and engagement of collars in the casing with the casing collar locator.

"APPARATUS AND METHODS FOR WELLBORE COMPLETION"

FIELD

Embodiments disclosed herein relate to apparatus and methods for completion of a wellbore and, more particularly, to apparatus and methods for fracturing a formation.

BACKGROUND

It is well known to line wellbores with liners or casing and the like and, thereafter, to create flowpaths through the casing to permit fluids, such as fracturing fluids, to reach the formation therebeyond.

One such conventional method for creating flowpaths is to perforate the casing using apparatus such as a perforating gun, which typically utilize an explosive charge to create localized openings through the casing.

Alternatively, the casing can include pre-fit ports, located at intervals therealong. The ports are typically sealed, such as by a dissolvable plug, a burst port assembly, a sleeve or the like, during insertion of the casing into the wellbore. Optionally, the casing can thereafter be cemented into the wellbore, the cement being placed in a well annulus between the wellbore and the casing. Thereafter, the ports are typically selectively opened by actuating the sealing means to permit fluids to reach the formation.

Typically, when sleeves are used to seal the ports, the sleeves are releasably retained over the port and can be actuated to slide relative to the casing to open the port. Many different types of sleeves and apparatus to actuate the sleeves are known in the industry.

Canadian Patent Application 2,738,907 to NCS Oilfield Services Canada Inc., teaches casing pre-fit with ported subs and a bottomhole assembly (BHA) deployed at an end of coiled tubing, one form of which is shown in Fig. 1A. The BHA has a sealing member and a releasable anchor which are set inside the ported sub, more particularly inside a slidable sleeve of the ported sub, for shifting the sleeve in the wellbore and opening ports in the casing. From an uphole end, the BHA comprises a connector or pull tube to the coiled tubing, a fluid-cutting assembly such as a jet cutting tool, a check valve, a bypass/equalization valve, the sealing member, the releasable anchor and a sleeve locator. To ensure alignment of the BHA and the ports, the sleeve locator co-operates with a profiled section of the sleeve. The relatively long BHA is positioned within the sliding sleeve section of the cased wellbore using the sleeve locator which engages a profiled section of a downhole end of the sleeve of the ported sub. A mechanical force is applied, using the coiled tubing, to set the anchor and the sealing element and to close the bypass/equalization valve. One or both of a downward force and fluid pressure is applied to shift the sleeve. The equalization valve is positioned between the abrasive fluid jetting assembly and the sealing element. The equalization valve effectively seals the bore of the coiled tubing below the jetting assembly except when released, by pulling uphole on the coiled tubing, to equalize pressure and permit the BHA to be moved within the wellbore. The check valve is adjacent, but downhole of the jetting assembly to prevent fluid delivered through the coiled tubing from moving beyond the jetting assembly. Thus, fluid delivered through the coiled tubing is only used to cut perforations.

Treatment fluid, such as for fracturing, is delivered through the annulus between the BHA and the casing, to the ports opened by the sleeve. As one of skill will appreciate, the volume of treatment fluid which must be pumped through the large annulus, is sufficiently larger than that which would be required to be pumped through the smaller coiled tubing. Not all formations require such larger volumes and the cost of treatment fluids is not inconsequential to the overall costs of a fracturing operation.

In order to accommodate the length of the overall BHA in the wellbore, extending from the pull tube to the lower sleeve locator, the ports in the ported sub must be spaced sufficiently above an adjacent casing collar therebelow. The spacing necessitates a relatively long sleeve to extend from above the ports, for covering the ports in a closed position, to at least the sleeve locator which engages a lower end of the sleeve for positioning the BHA. The ported sub and sleeve assembly is a machined assembly and is expensive. The additional length required to accommodate the BHA further increases the materials and machining costs.

There is interest in the industry for apparatus and methods of performing completion operations which are relatively simple and which reduce the overall costs involved.

SUMMARY

In embodiments disclosed herein, a plurality of ported subs are incorporated into casing and are each located for treatment of the formation therethrough, as desired, using a BHA deployed on coiled tubing therein for delivering treatment fluid through selectively opened treatment ports in the located ported sub to the formation. A sealing element on the BHA blocks a treatment annulus between the ported sub and the BHA below the treatment ports, treatment fluid being deliverable to the treatment ports via the treatment annulus. A bore of the BHA is blocked below fluid ports therein through which the treatment fluid is delivered via the coiled tubing. Thus, treatment fluid can be delivered to the treatment ports through the coiled tubing, through the treatment annulus or through both.

In a broad aspect, a system for treatment of a formation from a wellbore cased with casing, the cased wellbore penetrating the formation, the system comprising: a plurality of ported subs incorporated in the casing and forming a contiguous casing bore. Each ported sub has a plurality of treatment ports formed therethrough between the casing bore and the formation, and at least a sleeve for selectively opening and closing the plurality of treatment ports. A bottom hole assembly (BHA) is deployable on coiled tubing through the casing bore and forms a treatment annulus therebetween. Treatment fluid is deliverable to the BHA through the coiled tubing. The BHA has a BHA bore contiguous with the coiled tubing and at least a treatment sub having fluid ports therein for fluid communication between the

BHA bore and the treatment annulus; a resettable sealing element spaced downhole the treatment sub for releasably sealing the treatment annulus therebelow; and a fluid block in the BHA bore downhole the treatment sub for blocking treatment fluid therebelow. When the sealing element seals the treatment annulus, treatment fluid is deliverable through the treatment ports either through the coiled tubing and fluid ports, through the treatment annulus, or through both the coiled tubing and fluid ports, and the treatment annulus.

The BHA further comprises an abrasive fluid jetting apparatus uphole from the treatment sub for cutting jetted openings in the casing or ported sub in the event that treatment ports cannot be opened in the ported sub or that a ported sub is not positioned in the casing at a zone of interest. A jet valve in the jetting apparatus can be closed to permit temporary blocking of fluid flow below the jetting apparatus. Abrasive fluid is delivered through the coiled tubing to jet ports in the jetting apparatus for cutting the openings. After the openings are cut, the jet valve is opened and fluid is permitted to flow through the jet valve to the treatment sub therebelow.

In another broad aspect, a method of treating a formation comprises: deploying a bottom hole assembly (BHA) on coiled tubing into a cased wellbore penetrating the formation and forming a treatment annulus therebetween. A ported sub is located in the cased wellbore, using the BHA for positioning fluid ports of a treatment sub adjacent treatment ports of the ported sub. The treatment annulus is sealed below the treatment sub. The ported sub is actuated to open the treatment ports and treatment fluid is delivered to the opened treatment ports through either the coiled tubing to the fluid ports, through the treatment annulus or both.

Where treatment ports fail to open jetted openings can be cut in the cased wellbore by temporarily blocking fluid flow to the treatment sub and delivering abrasive fluid to a fluid jet assembly above the treatment sub. Thereafter, the fluid flow is unblocked to the treatment sub to permit fluid flow to the fluid ports.

BRIEF DESCRIPTION OF THE DRAWINGS

Figure 1A is a side view of a prior art BHA, deployable on coiled tubing, a sleeve locator engaging a profiled end of a sleeve for positioning the BHA relative to treatment ports in a ported sub for opening the treatment ports for performing a completion operation therethrough;

Figure 1B is a side view of a coil tubing deployed BHA according to an embodiment described herein, the ported sub having a relatively short sleeve compared to that of Fig. 1A, and a casing collar locator engaging a casing collar of the ported sub for positioning the BHA relative to treatment ports in the ported sub;

Figure 2A is a diagrammatic cross-sectional view of a cased wellbore and BHA, according to an embodiment, deployed in the cased wellbore on coiled tubing, the sleeve having been actuated to open treatment ports in the casing;

Figure 2B is a close-up diagrammatic cross-sectional view of a BHA according to an embodiment deployed in casing having a ported sub therein the ported sub having a sleeve and forming a treatment annulus therebetween, the

BHA's bore being blocked by a one-way valve positioned therein below fluid ports in a treatment sub and the treatment annulus being sealed by a resettable sealing element below the fluid ports;

Figure 3 a diagrammatic cross-sectional view according to Fig. 2A, a treatment fluid being delivered through an annulus between the wellbore and the BHA, to the open treatment ports for fracturing a formation thereabout;

Figure 4 is a diagrammatic cross-sectional view according to Fig. 2A, the treatment fluid being delivered through coiled tubing to the fluid ports for delivery to the open treatment ports for fracturing the formation thereabout;

Figure 5 is a diagrammatic cross-sectional view according to Fig. 2A, fluid being delivered to either the annulus or the coiled tubing for reverse circulation to surface for clearing debris from the annulus and/or the BHA;

Figure 6 is a diagrammatic cross-sectional view according to Fig. 2A, a bore of the coiled tubing being reversibly sealed below an abrasive fluid jetting apparatus, fluid being delivered through the coiled tubing to the abrasive fluid jetting apparatus for cutting jetted openings in the casing;

Figure 7 is a diagrammatic cross-sectional view according to Fig. 6, the bore of the coiled tubing being cleared by reverse circulation of fluid to surface for fracturing the formation through the jetted openings cut in the casing; and

Figure 8 is a close-up diagrammatic cross-sectional view according to Fig. 2B, having chemical or fluid retarder in treatment ports in the ported casing, cement outside the ported casing being disrupted or prevented from setting up.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENT

Embodiments disclosed herein describe apparatus and methods for treatment of a wellbore which penetrates or otherwise intersects one or more zones of interest in a formation.

Having reference to Figs. 1B-7, and in embodiments described below, a bottom-hole apparatus (BHA) 10, has a bore 11 formed therethrough which is contiguous with the bore 13 of the coiled tubing 20, which enables at least delivery of treatment fluid F to the formation 12. As shown in Figs. 2A, 3 and 4, fluid F can be delivered through a treatment annulus 14 between the BHA 10 and casing 16 in a wellbore 18 (Fig. 3), through the bore 13 of the coiled tubing 20 to the bore 11 of the BHA 10 (Fig. 4), or through both the treatment annulus 14 and the coiled tubing 20 (Fig. 2A).

Advantageously, the ability to deliver fluids through both the treatment annulus 14 and the coiled tubing 20 or both simultaneously, effectively permits altering the volume of treatment fluid F delivered to match the conditions. In treatment operations which require only low treatment rates, treatment fluid F can be saved by pumping down the smaller diameter coiled tubing 20 rather than through the higher volume treatment annulus 14. In treatment operations requiring a higher treatment rate, larger amounts of treatment fluid F can be delivered down the treatment annulus 14. Where even higher treatment rates are required, the treatment fluid F can be delivered simultaneously through both the treatment annulus 14 and the coiled tubing 20.

Embodiments of the BHA 10 are intended for use in completion of new, cased wellbores 18 which do not have existing perforations, or ports therethrough which are open to the formation 12. The wellbores 18 are completed with a plurality of ported subs 22, having a plurality of pre-formed treatment ports 24 formed therein. The plurality of ported subs 22 are incorporated into the casing 16, such as by casing collars 28 at, at least, a downhole end 29 thereof and are spaced at intervals along a length of the wellbore 18 and forming a contiguous casing bore 19. In each ported sub 22, a sleeve 26 is operatively connected the treatment ports 24. The sleeve 26 typically covers the treatment ports 24 until such time as the sleeve 26 is selectively actuated to open the treatment ports 24 for delivery of treatment fluid F therethrough.

The embodiments disclosed herebelow are described in the context of a fracturing operation however as one of skill in the art will appreciate, the embodiments may also be used for other types of treatment where treatment fluids, such as acidizing fluids and the like, are applied into the formation.

Fig. 2B represents a structural embodiment of a BHA 10 according to embodiments described herein. Figs. 2A, and 3 to 7 are diagrammatic only and show a sleeve 26 positioned on an outside of casing 16 and a casing collar locator 46 engaging a casing collar 28 on an inside of the casing 16 which coincides with a downhole end of the sleeve 26 and are used herein to illustrate flow of fluids only, during use thereof.

Having reference to Figs. 3 and 4, fracturing, which results from the delivery of pressurized treatment fluid F to the formation, is performed through the treatment ports 24, after the sleeve 26 associated therewith are selectively actuated for opening the treatment ports 24. Treatment ports 24 are generally opened sequentially from a downhole end of the formation 12 to an uphole end of the formation 12. In a horizontal wellbore 18, the treatment ports 24 are generally opened sequentially from a toe 30 of the wellbore 18 to a heel 32 of the wellbore 18.

As shown in Fig. 2B, a BHA 10, comprises, from a distal end 34 to a proximal end 36, at least a resettable sealing element 38 and a treatment sub 40, such as a blast joint, positioned thereabove. The treatment sub 40 has fluid ports 42 formed therein for at least delivery of treatment fluid F from the coiled tubing 20, to the treatment ports 24. In embodiments, the resettable sealing element 38 is a resettable packer, such as a packer having resettable anchoring elements 44, for sealing the wellbore 18 below the treatment ports 24. The treatment sub 40 is fluidly connected to the bore 13 of the coiled tubing 20 therein for delivering treatment fluid F to the open treatment ports 24 in the ported sub 22 to the formation 12 therebeyond. The bore 11 of the BHA 10 is sealed or blocked below the fluid ports 42 to prevent the flow of treatment fluid F delivered through the coiled tubing 20 from flowing through the BHA's bore 11 therebelow.

Further, as described in greater detail below, a fluid block 50 in the BHA's bore 11 directs fluid entering the fluid ports 42 from the treatment annulus 14 to be recirculated to surface S. Thus, having both the treatment annulus 14 and the BHA's bore 11 sealed below treatment ports 24 and the treatment sub 40, fluid communication is open between the coiled tubing 20 and the treatment annulus 14 and treatment fluid F can be delivered to the treatment ports 24 through either or both.

As shown in Fig. 1B, embodiments of the BHA 10 enable significantly shorter sleeves 26 than conventional sliding sleeves. Embodiments enable shortening of the sleeves 26 to a length L, about ½ a length L_p of conventional prior art sleeves 26_p, such as required for a BHA 10 as taught in CA 2,738,907 to NCS Oilfield Services Canada Inc. (Fig. 1A). Applicant believes that the prior art sleeves 26_p are typically about 7-8 feet in length whereas, in embodiments disclosed herein, the sleeves 26 are able to be shortened to about 3 feet in length. Thus, overall costs for performing a treatment operation are reduced.

In embodiments disclosed herein, to enable shortening of the sleeves 26 compared to conventional sliding sleeves, at least the resettable sealing element 38 is positioned immediately adjacent and downhole of the treatment sub 40 resulting in a significant reduction in the length of the ported sub 22, the sleeves 26 and the BHA 10 (Fig. 1B), compared to that of the prior art.

In embodiments, the BHA 10 further comprises a conventional casing collar locator CCL 46 which detects the collars 28 in the casing 16, rather than a bottom of the sliding sleeve, as in the prior art. Thus, the casing collar locator 46 is used to locate the BHA 10 based on a location of the casing or locating collar 28 adjacent and downhole of the ported sub 22. Accordingly, the ported sub 22 and sleeves 26 do not need to be as long as the prior art and the casing collar locator 46 does not need to be a specialized casing collar locator for detecting a profile at the lower end of the prior art ported sub and sliding sleeve therein.

In embodiments, the casing collar locator 46 is spaced below the resettable sealing element 38 by a length of relatively inexpensive pup joint 48, positioning the casing collar locator 46, when engaged, to appropriately position the fluid ports 42 at or near the treatment ports 24 when the casing collar locator 46 engages the locating collar 28. In embodiments, the downhole end 29 of the ported sub 22, the locating collar 28 or lengths of adjacent casing 16 are aggressively profiled to assist detection by the casing collar locator 46.

In use for treating the formation 12, the BHA 10 is deployed on the coiled tubing 20 into the cased wellbore 18 penetrating the formation 12 and forms the treatment annulus 14 therebetween. A ported sub 22, at a zone of interest, is located in the cased wellbore 18, using the BHA 10 for positioning the fluid ports 42 of the treatment sub 40 adjacent the treatment ports 24 of the ported sub 22. The treatment annulus 14 is sealed below the treatment sub 40, such as by setting the resettable sealing element 38. The ported sub 22 is actuated, such as by actuating the sleeve 26, to open the treatment ports 24. Treatment fluid F is delivered to the opened treatment ports 24 through either the coiled tubing 20 to the fluid ports 42, through the treatment annulus 14 or both.

Having reference again to Figs. 3 and 4, to permit pressure maintenance in the wellbore 18 during a fracturing operation, when treatment fluid F is delivered to the open treatment ports 24 through one or the other of the treatment annulus 14 or the coiled tubing 20, the other can act as a “dead leg”. As shown in Fig. 3, for example, when the treatment fluid F is delivered through the treatment annulus 14, a minimal, constant amount of a deadhead fluid P is delivered through the coiled tubing 20 to act as a “dead leg”, maintaining pressure within the coiled tubing 20. The pressure required to maintain the constant fluid delivery is monitored from surface S and can be used for calculating fracture extension pressure or failure to deliver treatment fluid F, such as resulting from debris buildup in the treatment annulus 14, as is understood by those of skill in the art. As shown in Fig. 4, when treatment fluid F is delivered to the fluid ports 42 through the coiled tubing 20, the treatment annulus 14 can be used as the “dead leg”. A minimal, constant amount of the deadhead fluid P is delivered to the treatment annulus 14 for maintaining pressure within the treatment annulus 14, the pressure therein being monitored at surface S and used as described above.

Having reference to Fig. 5, where debris relief is desired or required, in embodiments disclosed herein, reverse circulation of a clean-up fluid C to surface S is possible. The bore 11 of the BHA 10 below the treatment sub 40 is closed or blocked to circulation of fluid therethrough and the treatment annulus 14 below the treatment sub 40 and the treatment ports 24 is sealed by the sealing element 38. The delivery of the minimal, constant deadhead fluid P through either the treatment annulus 14 or the coiled tubing 20 acting as the "dead leg" is stopped and the clean-up fluid C is delivered through one of either the treatment annulus 14 or the coiled tubing 20 for reverse circulating the fluid C and debris to surface S. If, for example, fluid C is delivered through the coiled tubing 20 only, the fluid C and any debris encountered will be circulated to surface S through the treatment annulus 14. Similarly, if fluid C is delivered through the treatment annulus 14 only, the fluid C and any debris encountered will enter the fluid ports 42 and be circulated to surface S through the coiled tubing 20.

When the BHA 10 is to be moved within the wellbore 18, from interval of interest to interval of interest therein, pressure is equalized above and below the sealing element 38. In one embodiment, pressure is equalized through an equalization valve as is known in the art, such as a valve actuated by movement of the coiled tubing 20. Once the pressure is equalized, the resettable sealing element 38 and anchoring elements 44 are released and the BHA 10 is lifted in the wellbore 18 to the next interval to be fractured. Alternatively, the sealing element 38 is first released, commencing a wash-by of fluid around the sealing element 38 which equalizes the fluid pressure around the sealing element 38. The sealing element 38 may be released in reverse of setting.

Having reference again to Fig. 2B, in embodiments, the bore 11 of the BHA 10 having the fluid block 50, is blocked to the flow of fluid downhole therethrough. In embodiments the fluid block 50 is a one-way or check valve positioned below the treatment sub 40 which can also act as a pressure equalization valve. In embodiments, the check valve 50 is in the bore 11 above the sealing element 38 or is within the sealing element 38. The check valve 50 is thus positioned below the treatment sub 40 and does not impede the flow of treatment fluid F through the coiled tubing 20 to reach the treatment sub 40, and yet blocks flow downhole thereof.

Where the check valve 50 comprises a ball 52 and a ball seat 54, the ball 52 can be biased to an open position permitting pressure equalization therethrough when running the BHA 10 into the wellbore 18. During treatment operations, treatment fluid F acting at the ball 52 causes the ball to seat in the ball seat 54 to block the flow of fluids therebelow. Thereafter, when the BHA 10 is to be moved for locating at another of the plurality of ported subs 22 or lifted from the wellbore 18, the flow of treatment fluid F is stopped and the valve 50 can be biased open to equalize pressure therethrough, permitting unsetting of the packer 38 and movement of the BHA 10.

Alternatively, valves opened and closed through mechanical actuation, such as lifting of the coiled tubing 20 or a mandrel associated with the sealing element 38, can be used to physically lift, dislodge or otherwise break the seal of the ball 52 from the ball seat 54, releasing the pressure thereacross enabling fluid to equalize through the check valve 50.

ABRASIVE JETTING FOR CUTTING OF TREATMENT PORTS

Having reference to Figs. 6 and 7, in a ported sub 22 or in casing 16 which does not have a sleeve 26 and fracture ports 24 positioned at an identified zone of interest in the formation 12 or where there is a failure to actuate an existing sleeve 26, jetted openings 58 can be cut in the casing 16 or ported sub 22 using a fluid jetting apparatus 60.

In embodiments, the fluid jetting apparatus 60 is incorporated into the BHA 10, adjacent and uphole of the treatment sub 40. The fluid jetting apparatus 60 has a jet bore 61 contiguous with the bore 11 of the BHA 10 and further comprises a plurality of jet ports 62 therein.

As shown in Fig. 6, an abrasive fluid A is delivered to the jet ports 62 through the bore 13 of the coiled tubing 20. A jet valve 64, when closed, blocks the flow of the abrasive fluid A to the BHA 10 below the fluid jet assembly 60. Thus, the abrasive fluid A is caused to exit through the plurality of jet ports 62 and is directed against the casing 16 or ported sub 22 for cutting the jetted openings 58.

When the jet valve 64 is open, such as during normal treatment operations or when delivering fluid for actuating sleeves 26 or the like, treatment fluid F can be delivered through the bore 13 of the coiled tubing 20 and through the fluid jet assembly 60 to the fluid ports 42 therebelow.

In an embodiment, the jet valve 64 further comprises a ball seat 66 located in the BHA's bore 11, downhole of the fluid jetting apparatus 60 and uphole of the treatment sub 40.

In use for creating the jetted openings 58, the BHA 10 is positioned in the wellbore 18 adjacent the zone of interest and the sealing element 38 and resettable anchoring elements 44 are set against the sleeve 26 which cannot be actuated or against the bare casing 16. The sealing element 38 is actuated to seal the treatment annulus 14 below the treatment sub 40. A ball 68 is dropped through the bore 13 of the coiled tubing 20 into the bore 11 of the BHA 10, as is conventionally known for prior art sleeve shifting operations. The ball 68 seals at the ball seat 66 to close the jet valve 64 for temporarily blocking the flow of fluid below the fluid jetting apparatus 60. The abrasive fluid A is then delivered to the fluid jetting apparatus 60.

Thereafter, as shown in Fig. 7, the jet valve 64 is openable by releasing the ball 68 from the ball seat 62 to permit fluid flow through the coiled tubing 20 to the BHA 10 therebelow. One method of removing or releasing the ball 68 is by reverse circulation to surface S, wherein a fluid is delivered to the treatment annulus 14, enters the fluid ports 42 and lifts the ball 68 to surface within the bore 13 of the coiled tubing 20.

Another method for opening the jet valve 64 is to release or remove the ball 68 either through pressure or flow management to a storage trap. For example, a release mechanism, including a resilient ball seat 66, can be used to permit the ball 68 to be forced, at a threshold pressure, through the ball seat 66, the released ball 68 thereafter being retained or sequestered out of the flow of fluid, such as in a ball cage positioned downhole from the treatment sub 40. In yet a further embodiment, the ball 68 can be reverse circulated out of the ball seat 66, but retained downhole and out of the flow of fluid, such as in a recess.

In a fracturing operation, using an embodiment comprising the fluid jetting apparatus 60 and following cutting of the jetted openings 58, where treatment fluid F is applied to the formation through the coiled tubing 20, minor amounts of treatment fluid F may also leak or pass from the coiled tubing 20 to the treatment annulus 14 through the plurality of jet ports 62 in the fluid jetting assembly 60. Applicant believes the overall loss of treatment fluid F is small compared to the major volume which is delivered to the fluid ports 42 in the treatment sub 40. Advantageously, the small amount of treatment fluid F exiting the plurality of jet ports 62 may act to clear any debris, such as cement, in the treatment annulus 14 following actuation of the sleeve 26.

In embodiments, the sleeves 26 can be rotationally actuated to open the treatment ports 24, such as to align sleeve ports 70 in the sleeves 26 with the treatment ports 24. Alternatively, the sleeves 26 can be sliding or shifting sleeves 26 which are moved axially within the ported sub 22 for opening the treatment ports 24. In embodiments, the sleeve 26 can be actuated by shifting to align the sleeve ports 70 with the treatment ports 24 to permit fluid connection between the coiled tubing 20, the treatment annulus 14 and the formation 12. In embodiments, the sleeve 26 is instead actuated by shifting the sleeve 26 axially past the treatment ports 24, for exposing the treatment ports 24 and providing fluid communication between the coiled tubing 20, the treatment annulus 14 and the formation 12.

In an embodiment, the resettable sealing element 38 and resettable anchoring elements 44 are set and engage an inner surface 72 of the sleeve 26 for enabling actuation of the sleeve 26.

In one approach, the coiled tubing 20 is used to apply a force to the BHA 10 which causes the sealing element 38 to expand and engage the inner surface 72 of the sleeve 26 and further actuates the resettable anchoring elements 44 to also engage the sleeve 26. Continued force on the BHA 10 causes the sleeve 26 to shift axially therein and open the treatment ports 24. Alternatively, application of fluid pressure, acting against the sealing element 38 acts to assist or provide substantially the entirety of the force to release the sleeve 26 from the ported sub 22, such as to overcome shear pins operatively connected therebetween, and to axially shift the sleeve 26.

In an embodiment, having reference again to Fig. 2B, the sealing element 38 is a packer which is actuated to engage the casing 16 or the sleeve 26 and seal the treatment annulus 14 between the BHA 10 and the sleeve 26. The resettable anchoring elements 44 are a series of slips which are actuated, such as by a cone 74. Once actuated the cone 74 moves axially into the slips 44, driving the slips 44 outward into engagement with the casing 16 or the sleeve 26 thereabout for gripping the casing 16 or for gripping the sleeve 26 for actuation by axial shifting of the sleeve 26. The actuation can be controlled with a J-slot arrangement or other suitable mode selection apparatus, for retaining the slips 44 in a ready-mode, a set mode, and a release mode, as is understood in the art.

Alternatively, other means or actuating tools may be used to rotate or axially shift the sleeve 26.

Advantageously, in all embodiments disclosed herein, upon removal of the BHA 10 or any actuation tools used to actuate the sleeves 26 after all zones of interest in the formation 12 have been treated or fractured, the wellbore 18 retains its full diameter. This is in direct contradistinction to other prior art, ball-drop-type sliding sleeve systems, wherein at least a plurality of ball seats and related hardware remain in the wellbore 18, restricting the wellbore diameter at least at intervals therealong. Although one can drill out the ball seats in such prior art systems, such drilling out is not efficient and requires additional trips into the wellbore 18 with addition tools. Applicant is aware that retrievable ball seats have been attempted, but apparently with limited success in the field for a variety of reasons.

Applicant believes that the industry may be reluctant to accept the use of sleeves 26 in cemented casing as it is thought that the cement 80 outside the sleeves 26 and treatment ports 24 has proven difficult to break down. In an embodiment, a chemical or fluid retarder R is located in the treatment ports 24 of the ported sub 22, the retarder R mixing with the cement 80 after the cement job is pumped so the cement 80 around the treatment ports 24 does not cure, does not fully cure or is otherwise weakened, such as preventing or disrupting the cement 80 from setting up, chemically or mechanically around the treatment ports 24. The release of the chemical or retarder R may be time or temperature actuated, or can be triggered upon contact with cement 80.

THE EMBODIMENTS IN WHICH AN EXCLUSIVE PROPERTY OR PRIVILEGE IS CLAIMED ARE DEFINED AS FOLLOWS:

1. A system for treatment of a formation from a wellbore cased with casing, the cased wellbore penetrating the formation, the system comprising:

a plurality of ported subs incorporated in the casing and forming a contiguous casing bore, each ported sub having

a plurality of treatment ports formed therethrough between the casing bore and the formation, and

at least a sleeve for selectively opening and closing the plurality of treatment ports; and

a bottom hole assembly (BHA) deployable on coiled tubing through the casing bore and forming a treatment annulus therebetween, treatment fluid being deliverable to the BHA through the coiled tubing, the BHA having at least:

a BHA bore contiguous with the coiled tubing;

a treatment sub having fluid ports therein for fluid communication between the BHA bore and the treatment annulus;

a resettable sealing element spaced downhole the treatment sub for releasably sealing the treatment annulus therebelow; and

a fluid block in the BHA bore downhole the treatment sub for blocking treatment fluid therebelow,

wherein when the sealing element seals the treatment annulus, treatment fluid is deliverable through the treatment ports either through the coiled tubing and fluid ports,

through the treatment annulus, or

through both the coiled tubing and fluid ports, and the treatment annulus.

2. The system of claim 1 wherein the plurality of ported subs are spaced along the cased wellbore, each ported sub incorporated therein by a casing collar at, at least, a downhole end thereof, the BHA further comprising:

a casing collar locator spaced downhole of the sealing element for detecting the casing collar of the ported sub for positioning the BHA relative to the treatment ports.

3. The system of claim 1 wherein the BHA further comprises:

a fluid jet assembly positioned uphole from the treatment sub and having a jet bore contiguous with the BHA bore and a plurality of jet ports therein for fluid communication between the BHA bore and the treatment annulus,

the fluid jet assembly comprising a jet valve which

when open, permits treatment fluid to be delivered through the coiled tubing, through the fluid jet assembly and to the fluid ports in the treatment sub below; and when closed, blocks the jet bore to deliver fluid from the coiled tubing and through the plurality of jet ports for cutting jetted openings through the cased wellbore to access the formation.

4. The system of claim 3 wherein a major volume of the treatment fluid is delivered to the fluid ports and a minor volume of the treatment fluid leaks through the plurality of jet ports.

5. The system of claim 4 wherein the minor volume of the treatment fluid clears debris from the treatment annulus.

6. The system of claim 1 further comprising a pressure equalization valve for equalizing pressure above and below the sealing element so as to permit downhole movement of the BHA within the cased wellbore.

7. The system of claim 6 wherein the fluid block comprises the pressure equalization valve.

8. The system of claim 1 wherein the fluid block comprises a one-way valve positioned in the BHA bore below the treatment sub for blocking fluid delivery downhole and permitting fluid flow uphole therethrough.

9. The system of claim 8 wherein the one-way valve is within the BHA bore at about the resettable sealing element.

10. The system of claim 1 wherein the resettable sealing element is a resettable packer.

11. The system of claim 1 wherein the casing is cemented into the wellbore, the system further comprising a chemical or fluid retarder positioned in the treatment ports to weaken cement thereabout.

12. The system of claim 3 wherein the jet valve comprises:

a ball seat in the BHA bore downhole of the plurality of jet ports and closable using a ball, deployable through the coiled tubing, to seat in the ball seat.

13. The system of claim 12 wherein the jet valve is openable by circulating fluid down the treatment annulus, through the fluid ports and into the treatment sub for unseating the ball from the ball seat and circulating the ball therein up the coiled tubing.

14. The system of claim 1 wherein the jet valve is openable by applying fluid pressure to the ball above a threshold pressure to open the ball seat and pass the ball therethrough.

15. The system of claim 1 wherein each of the plurality of sliding sleeves is about 3 feet in length.

16. A method of treating a formation comprising:

deploying a bottom hole assembly (BHA) on coiled tubing into a cased wellbore penetrating the formation and forming a treatment annulus therebetween

locating a ported sub in the cased wellbore, using the BHA for positioning fluid ports of a treatment sub adjacent treatment ports of the ported sub;

sealing the treatment annulus below the treatment sub;

actuating the ported sub to open the treatment ports; and

delivering treatment fluid to the opened treatment ports through either the coiled tubing to the fluid ports, through the treatment annulus or both.

17. The method of claim 16, before delivering the treatment fluid to the opened treatment ports wherein the BHA has a bore formed therethrough and a pressure equalization valve located therein, further comprising:

blocking the flow of treatment fluid through the BHA's bore below the treatment sub using the pressure equalization valve; and

following delivery of treatment fluid therethrough, opening the pressure equalization valve for moving the BHA in the cased wellbore.

18. The method of claim 16 wherein the locating of the ported sub comprises engaging a locating collar at a downhole end of the ported sub with a casing collar locator at downhole end of the BHA.

19. The method of claim 16, wherein delivering treatment fluid through the coiled tubing and fluid ports to the opened treatment ports further comprises delivering deadhead fluid through the treatment annulus.

20. The method of claim 16, wherein delivering treatment fluid to the plurality of treatment ports through the treatment annulus further comprises delivering a deadhead fluid through the coiled tubing.

21. The method of claim 16, wherein when the treatment ports fail to open, jetted openings are formed in the cased wellbore to access the formation using a fluid jet assembly comprising:

temporarily blocking fluid flow to the treatment sub;

delivering an abrasive fluid through a fluid jet assembly above the treatment sub for cutting one or more jetted openings therein; and

unblocking the fluid flow to the treatment sub to permit fluid flow to the fluid ports.

22. The method of claim 21 wherein

the temporary blocking of the fluid flow comprises deploying a ball down the coiled tubing to seal at a ball seat in a jet valve uphole of the treatment sub; and

the unblocking of the fluid flow comprises circulating the ball off of the ball seat.

23. The method of claim 22 wherein the circulating the ball off of the ball seat further comprises delivering fluid through the treatment annulus and through the delivery fluid for lifting and recirculating the ball up the coiled tubing.

24. The method of claim 21 wherein the method of unblocking the fluid flow comprises applying pressure at a threshold for passing the ball through the ball seat.

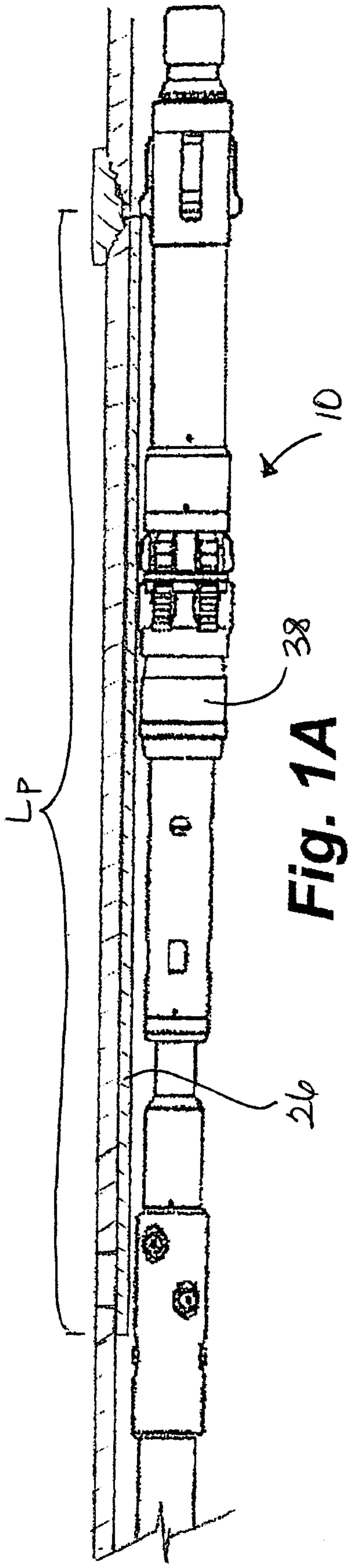

Fig. 1A
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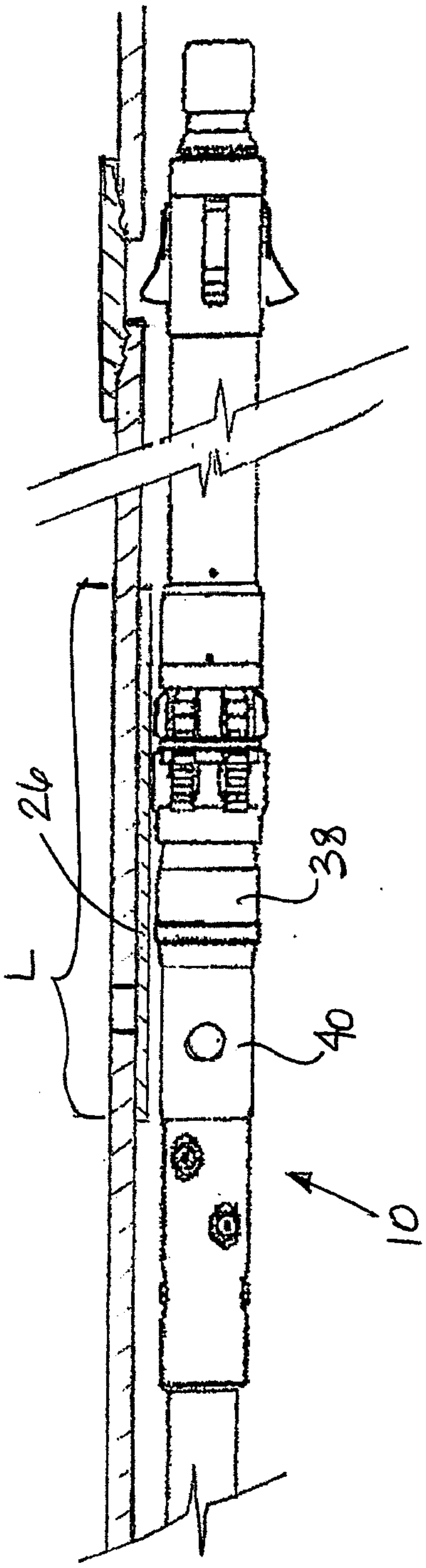

Fig. 1B

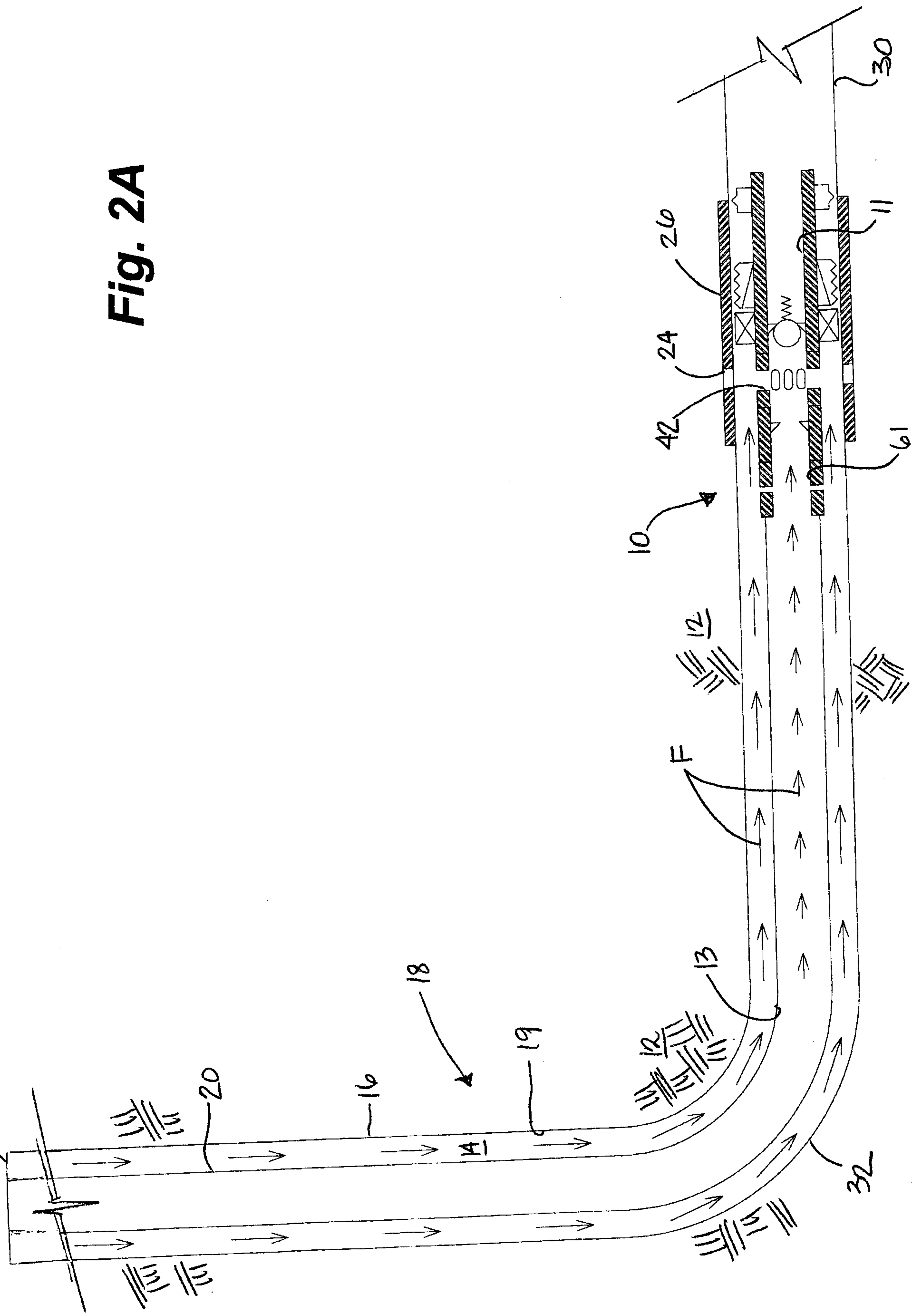

Fig. 2A

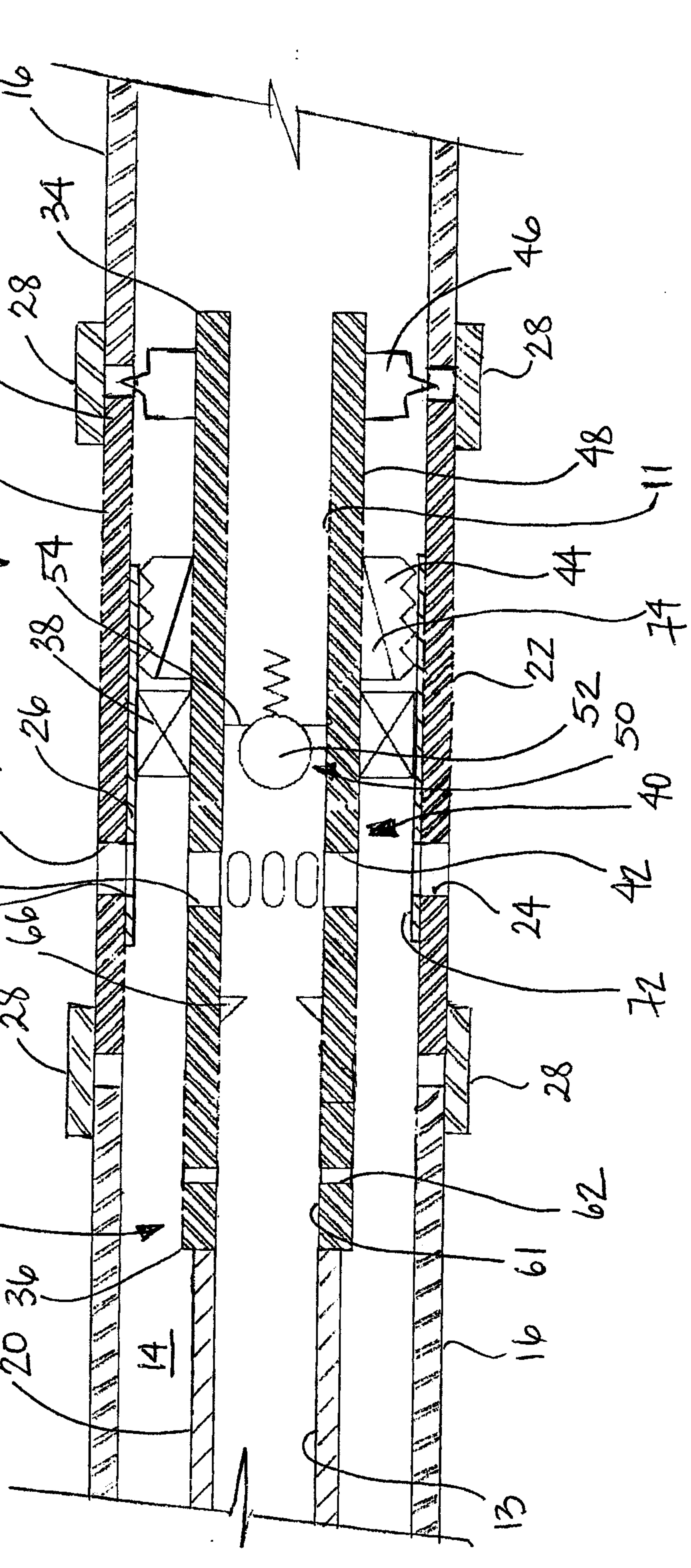
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FIG. 2B

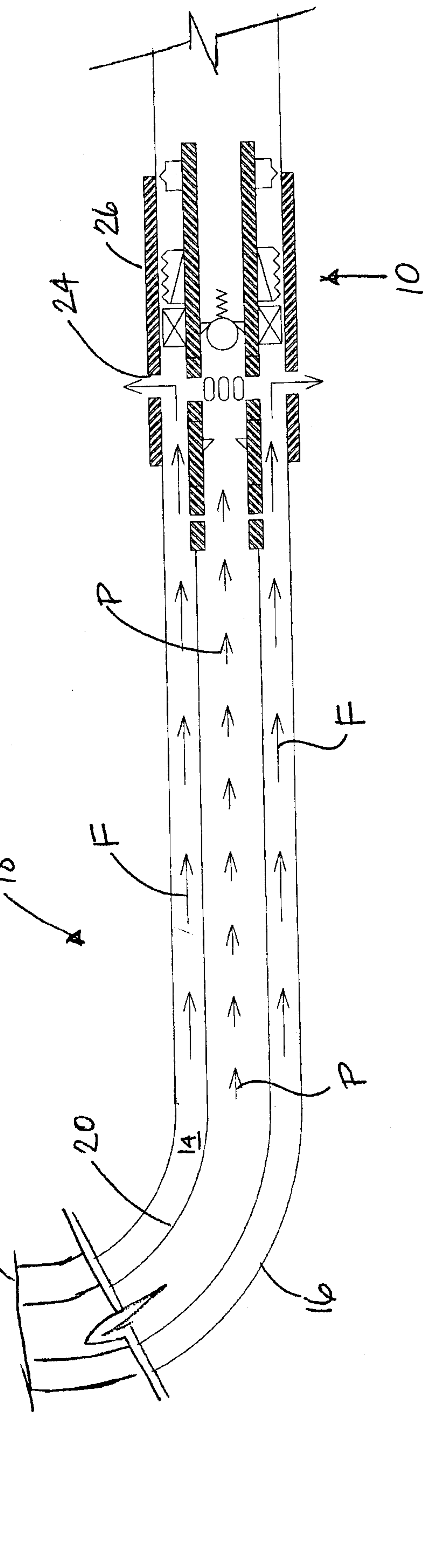

Fig. 3

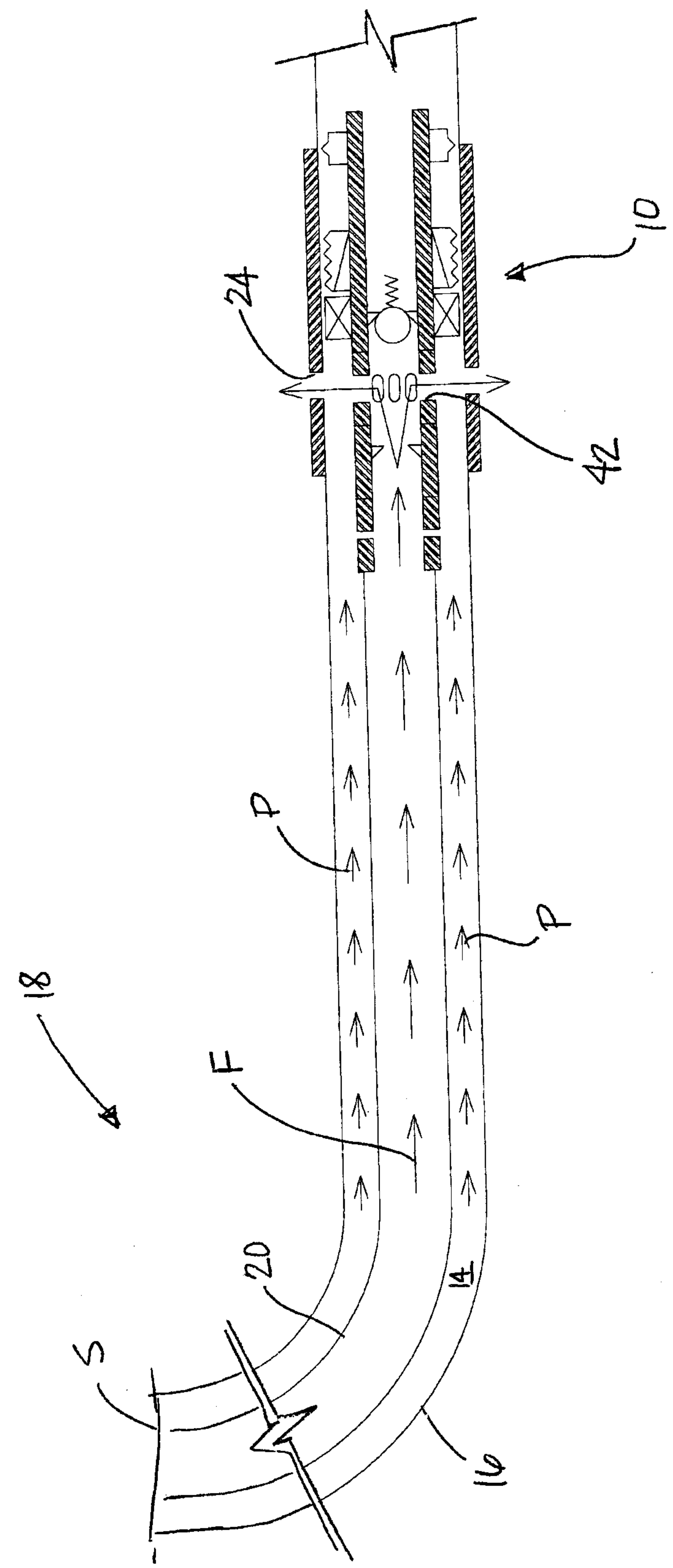

Fig. 4

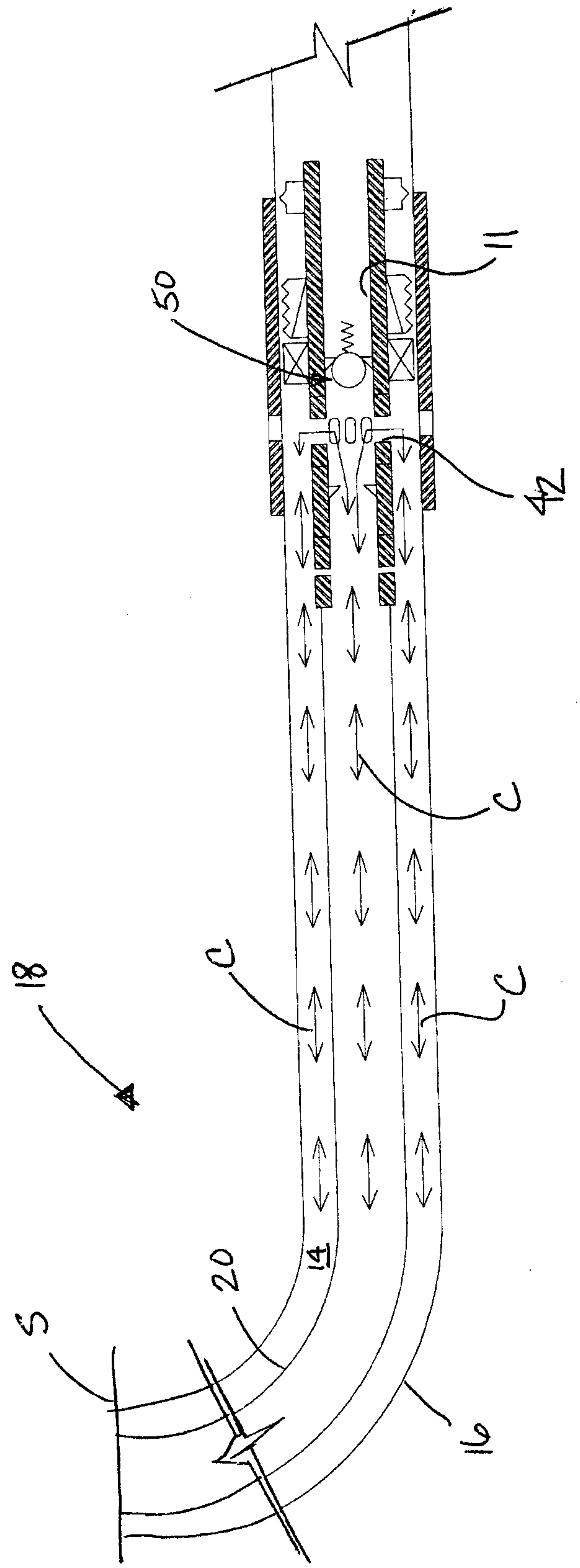

Fig. 5

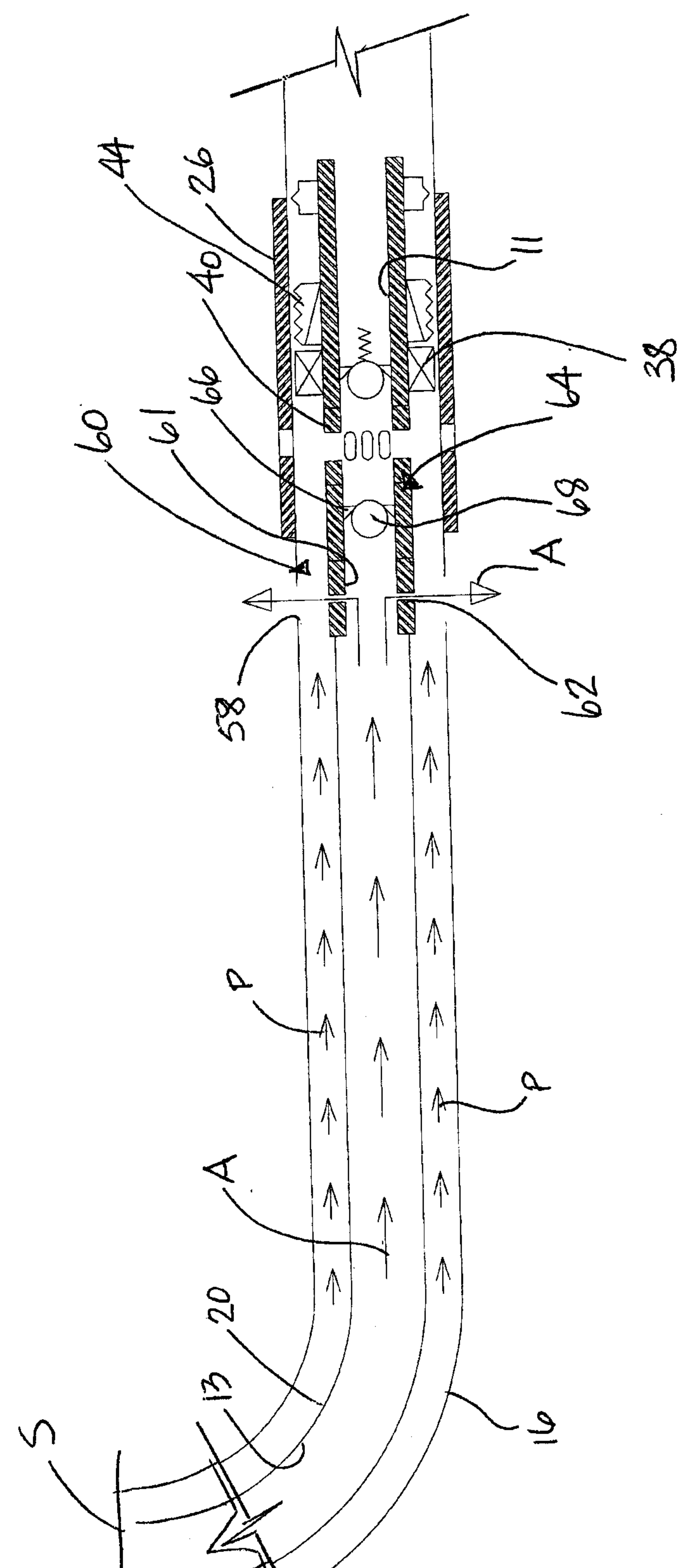

Fig. 6

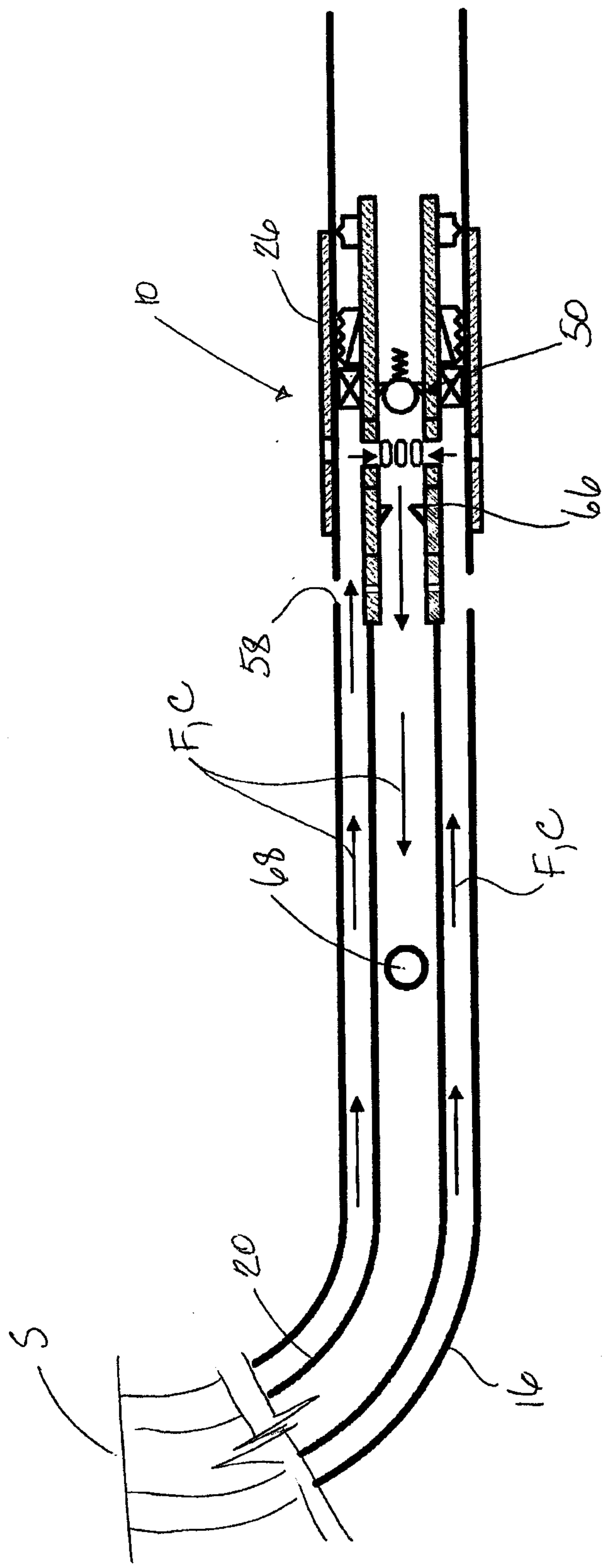

Fig. 7

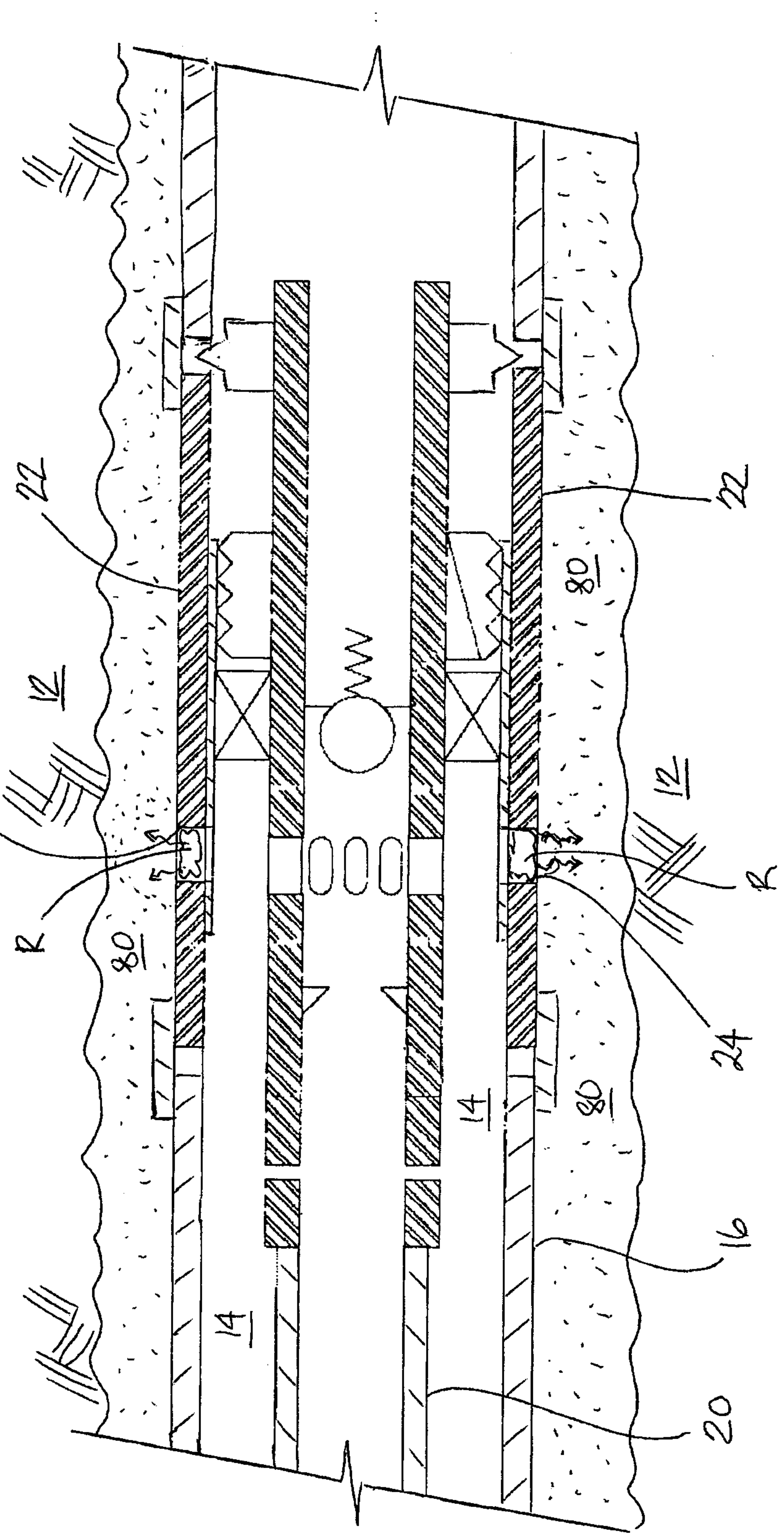

FIG. 8

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