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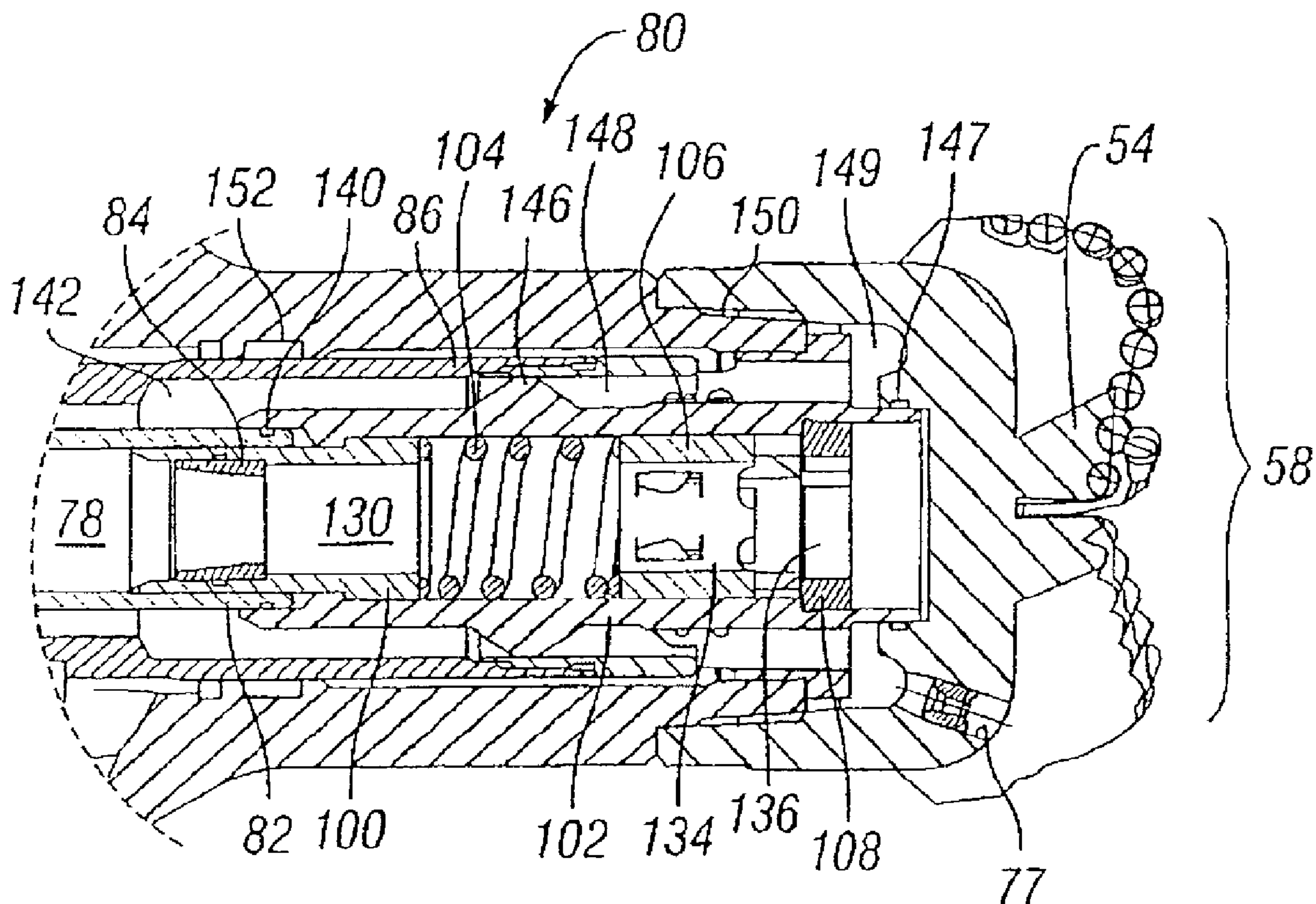
(71) Demandeur/Applicant:
SMITH INTERNATIONAL, INC., US

(72) Inventeurs/Inventors:
CAMPBELL, JOHN E., US;
DEWEY, CHARLES H., US;
UNDERWOOD, LANCE D., US;
SCHMIDT, RONALD G., US

(74) Agent: SMART & BIGGAR

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(57) Abrégé/Abstract:

An expandable drilling apparatus is deployed upon a distal end of a drillstring and includes a cutting head and a substantially tubular main body adjacent the cutting head providing a plurality of axial recesses configured to receive arm assemblies configured to translate between a retracted and an extended position. A flow switch actuates the arm assemblies when a drilling fluid pressure exceeds an activation value and the drilling apparatus includes a biasing member to reset the arm assemblies when the drilling fluid pressure falls below a reset value.

Abstract

An expandable drilling apparatus is deployed upon a distal end of a drillstring and includes a cutting head and a substantially tubular main body adjacent the cutting head providing a plurality of axial recesses configured to receive arm assemblies configured to translate between a retracted and an extended position. A flow switch actuates the arm assemblies when a drilling fluid pressure exceeds an activation value and the drilling apparatus includes a biasing member to reset the arm assemblies when the drilling fluid pressure falls below a reset value.

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DRILLING AND HOLE ENLARGEMENT DEVICE

This is a Divisional of Canadian Patent Application No. 2573891 filed January 15, 2007.

Background of Invention

[0001] In the drilling of oil and gas wells, typically concentric casing strings are installed and cemented in the borehole as drilling progresses to increasing depths. Each new casing string is supported within the previously installed casing string, thereby limiting the annular area available for the cementing operation. Further, as successively smaller diameter casing strings are suspended, the flow area for the production of oil and gas is reduced. Therefore, to increase the annular space for the cementing operation, and to increase the production flow area, it is often desirable to enlarge the borehole below the terminal end of the previously cased borehole. By enlarging the borehole, a larger annular area is provided for subsequently installing and cementing a larger casing string than would have been possible otherwise. Accordingly, by enlarging the borehole below the previously cased borehole, the bottom of the formation can be reached with comparatively larger diameter casing, thereby providing more flow area for the production of oil and gas.

[0002] Various methods have been devised for passing a drilling assembly through a cased borehole, or in conjunction with expandable casing to enlarging the borehole. One such method involves the use of an underreamer, which has basically two operative states--a closed or collapsed state, where the diameter of the tool is sufficiently small to allow the tool to pass through the existing cased borehole, and an open or partly expanded state, where one or more arms with cutters on the ends thereof extend from the body of the tool. In this latter position, the underreamer enlarges the borehole diameter as the tool is rotated and lowered in the borehole.

[0003] A "drilling type" underreamer is one that is typically used in conjunction with a conventional "pilot" drill bit positioned below (*i.e.* downstream of) the underreamer. Typically, the pilot bit drills the borehole to a reduced gauge, while the underreamer, positioned behind the pilot bit, simultaneously enlarges the pilot borehole to full gauge. Formerly, underreamers of this type had hinged arms with roller cone cutters attached thereto. Typical former underreamers included swing out cutter arms that pivoted at an end opposite the cutting end of the cutting arms, with the cutter arms actuated by

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mechanical or hydraulic forces acting on the arms to extend or retract them. Representative examples of these types of underreamers are found in U.S. Patent Nos. 3,224,507; 3,425,500 and 4,055,226. In some former designs, the pivoted arms could break and fall free of the underreamer during the drilling operation, thereby necessitating a costly and time consuming "fishing" operation to retrieve them from the borehole before drilling could continue. Accordingly, prior art underreamers may not be capable of underreaming harder rock formations, may have unacceptably slow rates of penetration, or their constructed geometries may not be capable of handling high fluid flow rates. The vacant pocket recesses also tend to fill with debris while the cutters are extended, thereby hindering the desired collapse of the arms at the conclusion of the operation. If the arms do not fully collapse, the drill string may hang up when a trip out of the borehole is attempted.

[0004] Furthermore, conventional underreamers include cutting structures that are typically formed of sections of drill bits rather than being specifically designed for the underreaming function. As a result, the cutting structures of most underreamers do not reliably underream the borehole to the desired gauge diameter. Also, adjusting the expanded diameter of a conventional underreamer requires replacement of the cutting arms with larger or smaller arms, or replacement of other components of the underreamer tool. It may even be necessary to replace the underreamer altogether with one that provides a different expanded diameter.

[0005] Moreover, many underreamers are constructed to expand when drilling fluid is pumped through the drill string at elevated pressures with no indication that the tool is in the fully expanded position. Furthermore, many expandable downhole tools expand from a retracted state to an extended state through the rupture of a shear member within the tool. Consequently, once the shear member is ruptured, pressurized fluid flow through the tool will bias the cutting arms toward expansion. As such, a return to the "original" operating state whereby the cutting arms remain retracted at pressures below the rupture pressure is no longer possible. Therefore, it would be advantageous for a drilling operator to have the ability to control not only when the underreamer expands and retracts, but also have the ability to know the status of such expansion.

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[0006] Another method for enlarging a borehole below a previously cased borehole section involves the use of a winged reamer behind a conventional drill bit. In such an assembly, a conventional pilot drill bit is disposed at the distal end of the drilling assembly with the winged reamer disposed at some distance behind the drill bit. The winged reamer generally comprises a tubular body with one or more longitudinally extending "wings" or blades projecting radially outward from the tubular body. Once the winged reamer passes through any cased portions of the wellbore, the pilot bit rotates about the centerline of the drilling axis to drill a lower borehole on center in the desired trajectory of the well path, while the eccentric winged reamer follows the pilot bit and engages the formation to enlarge the pilot borehole to the desired diameter.

[0007] Yet another method for enlarging a borehole below a previously cased borehole section includes using a bi-center bit, which is a one-piece drilling structure that provides a combination underreamer and pilot bit. The pilot bit is disposed on the lowermost end of the drilling assembly, and the eccentric underreamer bit is disposed slightly above the pilot bit. Once the bi-center bit passes through any cased portions of the wellbore, the pilot bit rotates about the centerline of the drilling axis and drills a pilot borehole on center in the desired trajectory of the well path, while the eccentric underreamer bit follows the pilot bit engaging the formation to enlarge the pilot borehole to the desired final gauge. The diameter of the pilot bit is made as large as possible for stability while still being capable of passing through the cased borehole. Examples of bi-center bits may be found in U.S. Patent Nos. 6,039,131 and 6,269,893.

[0008] As described above, winged reamers and bi-center bits each include eccentric underreamer portions. Because of this design, off-center drilling is required to drill out the cement and float equipment to ensure that the eccentric underreamer portions do not damage the casing. Accordingly, it is desirable to provide an underreamer that collapses while the drilling assembly is in the casing and that expands to underream the previously drilled borehole to the desired diameter below the casing.

[0009] Further, due to directional tendency problems, these eccentric underreamer portions have difficulty reliably underreaming the borehole to the desired gauge diameter. With respect to a bi-center bit, the eccentric underreamer bit tends to cause the pilot bit to wobble and undesirably deviate off center, thereby pushing the pilot bit away from the preferred trajectory of the wellbore. A similar problem is experienced with winged reamers, which are only capable of underreaming the borehole to the desired gauge if the pilot bit remains centralized in the borehole during drilling. Accordingly, it is desirable to provide an underreamer that remains concentrically disposed within the borehole while underreaming the previously drilled borehole to the desired gauge diameter.

[0010] Furthermore, it is conventional to employ a tool known as a "stabilizer" in drilling operations. In standard boreholes, traditional stabilizers are located in the drilling assembly behind the drill bit to control and maintain the trajectory of the drill bit as drilling progresses. Traditional stabilizers control drilling in a desired direction, whether the direction is along a straight borehole or a deviated borehole.

[0011] In a conventional rotary drilling assembly, a drill bit may be mounted onto a lower stabilizer, which may be disposed approximately 5 or more feet above the bit. Typically the lower stabilizer is a fixed blade stabilizer and includes a plurality of concentric blades extending radially outwardly and azimuthally spaced around the circumference of the stabilizer housing. The outer edges of the blades are adapted to contact the wall of the existing cased borehole, thereby defining the maximum stabilizer diameter that will pass through the casing. A plurality of drill collars extends between the lower and other stabilizers in the drilling assembly. An upper stabilizer is typically positioned in the drill string approximately 30-60 feet above the lower stabilizer. There could also be additional stabilizers above the upper stabilizer. The upper stabilizer may be either a fixed blade stabilizer or, more recently, an adjustable blade stabilizer capable of allowing its blades to collapse into the housing as the drilling assembly passes through the narrow gauge casing and subsequently expand in the borehole below. One type of adjustable concentric stabilizer is manufactured by Andergauge U.S.A., Inc., Spring, Tex. and is described in U.S. Patent No. 4,848,490. Another type of adjustable concentric

stabilizer is manufactured by Halliburton, Houston, Tex. and is described in U.S. Patent Nos. 5,318,137, 5,318,138, and 5,332,048.

[0012] In operation, if only the lower stabilizer is provided, a "fulcrum" effect may occur because gravity displaces the lower stabilizer such that it acts as a fulcrum or pivot point for the bottom hole assembly. Alternatively, in rotary steerable and positive displacement mud motor applications, the fulcrum effect may also result from the bending loads transferred across the lower stabilizer from a directional mechanism. Namely, as drilling progresses in a deviated borehole, for example, the weight of the drill collars behind the lower stabilizer forces the stabilizer to push against the lower side of the borehole, thereby creating a fulcrum or pivot point for the drill bit. Accordingly, the drill bit tends to be lifted upwardly at a trajectory known as the build angle. Therefore, a second stabilizer is provided to offset the fulcrum effect. As the drill bit builds due to the fulcrum effect created by the lower stabilizer, the upper stabilizer engages the lower side of the borehole, thereby causing the longitudinal axis of the bit to pivot downwardly so as to drop angle. A radial change of the blades of the upper stabilizer can control the pivoting of the bit on the lower stabilizer, thereby providing a two-dimensional, gravity based steerable system to control the build or drop angle of the drilled borehole as desired.

Summary of Invention

[0013] According to one aspect of the invention, an expandable drilling apparatus is deployed upon a distal end of a drillstring and configured to drill a formation. The drilling apparatus preferably includes a cutting head to drill the formation and a substantially tubular main body adjacent the cutting head, wherein the main body provides at least one axial recess configured to receive an arm assembly, wherein the arm assembly is configured to translate between a retracted position and an extended position. Preferably, drilling apparatus includes a flow switch to actuate the arm assembly between the retracted and extended positions, wherein the arm assemblies are configured to extend when a drilling fluid pressure exceeds an activation value. Furthermore, the drilling

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apparatus preferably includes a biasing member configured to reset the arm assembly into the retracted position when the drilling fluid pressure falls below a reset value; wherein the arm assembly comprises multiple arm segments, wherein
5 each segment translates from the retracted position to the expanded position along linear grooves of differing slope.

[0014] According to another aspect of the invention, an expandable drilling apparatus connected to a drillstring includes a cutting head disposed upon a distal end of a
10 substantially tubular main body, wherein the main body provides a plurality of axial recesses adjacent to the cutting head. Additionally, the drilling apparatus preferably includes a plurality of arm assemblies retained within the axial recesses, wherein the arm assemblies are
15 configured to translate from a retracted position to an extended position along a plurality of grooves formed into walls of the axial recesses, wherein the arm assemblies are configured to translate from a retracted position to an extended position along a plurality of grooves formed into
20 walls of the axial recesses. Furthermore, the drilling apparatus preferably includes a piston configured to thrust the arm assemblies into the extended position when a pressure of fluids flowing through the drillstring is increased. Preferably, the arm assemblies include
25 stabilizer pads upstream from and adjacent to underreamer cutters.

[0014a] According to another aspect of the invention, an expandable drilling apparatus deployed upon a distal end of a drillstring and configured to drill a formation, the
30 expandable drilling apparatus comprising: a cutting head to drill the formation; a substantially tubular main body adjacent the cutting head, the main body providing at least one axial recess configured to receive an arm assembly; the

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arm assembly configured to translate between a retracted position and an extended position; a flow switch to actuate the arm assembly between the retracted and extended positions; wherein the flow switch comprises: a bore
5 providing an aperture in communication with a hydraulic chamber configured to extend the arm assembly; a flow tube slidably engaged within the bore isolating the aperture from drilling fluids when in a deactivated position; wherein the aperture is in communication with the drilling fluids in the
10 bore when the flow tube is in an activated position; a second biasing member extending between the flow tube and a spring retainer within the bore, the biasing member configured to bias the flow tube into the deactivated position; a nozzle disposed within the flow tube, the nozzle
15 configured to transmit a force to the flow tube corresponding to the drilling fluid pressure; and the force displacing the flow tube into the activated position when the drilling fluid pressure exceeds the activation value; wherein the arm assemblies are configured to extend when a
20 drilling fluid pressure exceeds an activation value; and a biasing member configured to reset the arm assembly into the retracted position when the drilling fluid pressure falls below a reset value.

[0015] According to another aspect of the invention, a
25 switch to divert drilling fluids from a bore of a downhole apparatus includes the bore providing an aperture in communication with a device to be activated and a flow tube slidably engaged within the bore isolating the aperture from the drilling fluids when in a deactivated position, wherein
30 the aperture is in communication with drilling fluids in the

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bore when the flow tube is in an activated position.

Additionally, the switch preferably includes a biasing member extending between the flow tube and a spring retainer within the bore, wherein the biasing member is configured to

5 bias the flow tube into the deactivated position.

Additionally, the switch preferably includes a nozzle disposed within the flow tube, wherein the nozzle is configured to transmit a force to the flow tube

corresponding to a pressure of drilling fluids flowing

10 therethrough with the force displacing the flow tube into the activated position when the pressure of the drilling fluids flowing therethrough exceed an activation value.

[0016] According to another aspect of the invention, a method of drilling a borehole includes disposing a drilling assembly having expandable arm assemblies adjacent to a cutting head upon a distal end of a drillstring.

Additionally, the method preferably includes drilling a pilot bore with the cutting head with the expandable arm assemblies in a retracted position. Furthermore, the method

20 preferably includes increasing pressure of drilling fluids and activating a flow switch within the drilling assembly to expand the expandable arm assemblies, underreaming the pilot bore with cutting elements of the expandable arm assemblies, and stabilizing the drilling assembly with stabilizer pads of the expandable arm assemblies; using the cutting head and the expandable arm assemblies as a single fulcrum point in a directional drilling operation.

[0016a] According to another aspect of the invention, a switch to divert drilling fluids from a bore of a downhole apparatus, the switch comprising: the bore providing an aperture in communication with a device to be activated; a flow tube slidably engaged within the bore isolating the aperture from the drilling fluids when in a deactivated

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position; the aperture in communication with drilling fluids in the bore when the flow tube is in an activated position; a biasing member extending between the flow tube and a spring retainer within the bore, the biasing member
5 configured to bias the flow tube into the deactivated position; a nozzle disposed within the flow tube, the nozzle configured to transmit a force to the flow tube corresponding to a pressure of drilling fluids flowing therethrough; and the force displacing the flow tube into
10 the activated position when the pressure of the drilling fluids flowing therethrough exceed an activation value.

Brief Description of Drawings

[0017] Figure 1 is a sectioned view of a drilling assembly in a retracted position in accordance with an
15 embodiment of the present invention.

[0018] Figure 1A is a close-up view of a portion of the drilling assembly of Figure 1.

[0019] Figure 2 is an end view drawing of the drilling assembly of Figure 1.

20 [0020] Figure 3 is an alternative sectioned view of a portion of the drilling assembly of Figure 1.

[0021] Figure 4 is a close-up detail view of a lower portion of a flow switch of the drilling assembly of Figure 1.

25 [0022] Figure 5 is a close-up detail view of an extension assembly of the drilling assembly of Figure 1.

[0023] Figure 6 is a cross-sectional view of the drilling assembly of Figure 1 taken at 6-6.

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[0024] Figure 7 is a cross-sectional view of the drilling assembly of Figure 1 taken at 7-7.

[0025] Figure 8 is a cross-sectional view of the drilling assembly of Figure 1 taken at 8-8.

5 [0026] Figure 9 is a cross-sectional view of the drilling assembly of Figure 1 taken at 9-9.

[0027] Figure 10 is a cross-sectional view of the drilling assembly of Figure 1 taken at 10-10.

[0028] Figure 11 is a sectioned view drawing of the
10 drilling assembly of Figure 1 in a fully extended position.

- [0029] Figure 12 is an isometric view of the drilling assembly of Figure 1 in the fully extended position.
- [0030] Figure 13 is an exploded isometric view of the extension assembly of Figures 1 and 11.
- [0031] Figure 14 is an isometric view of an arm assembly of the drilling assembly of Figures 1 and 11.
- [0032] Figure 15 is a cross-sectional view of the drilling assembly of Figure 11 taken at 15-15.
- [0033] Figure 16 is a cross-sectional view of the drilling assembly of Figure 11 taken at 16-16.
- [0034] Figure 17 is a cross-sectional view of a first alternative arm assembly extension mechanism in a retracted position in accordance with an embodiment of the present invention.
- [0035] Figure 18 is a cross-sectional view of the extension mechanism of Figure 18 in an extended position.
- [0036] Figure 19 is a cross-sectional view of a second alternative arm assembly extension mechanism in a retracted position in accordance with an embodiment of the present invention.
- [0037] Figure 20 is a cross-sectional view of the extension mechanism of Figure 19 in an extended position.

Detailed Description

- [0038] Embodiments of the invention relate generally to a drilling assembly to be used in subterranean drilling. More particularly, certain embodiments of the present invention generally include a drilling assembly that includes a pilot bit portion and an expandable underreamer/stabilizer portion within close axial proximity to one another to simultaneously underream the pilot bore. Furthermore, some embodiments of the present

invention include a flow switch to actuate the expansion of the expandable underreamer/stabilizer portion, such that an operator may discern with an increased degree of accuracy whether the drilling assembly is fully expanded or retracted. Furthermore, some embodiments of the present invention include an expandable drilling assembly that is capable of being reset to its original condition following expansion while remaining downhole. Furthermore, some embodiments of the present invention include an arrangement for an expandable stabilizer/cutter assembly wherein the cutter assembly is capable of expanding into the formation ahead of the stabilizer. United States Patent No. 6,732,812, incorporated by reference in its entirety herein, discloses an expandable downhole tool for use in a drilling assembly positioned within a wellbore.

[0039] Referring now to Figure 1, a drilling assembly 50 in accordance with an embodiment of the present invention is shown. Drilling assembly 50 is shown having a substantially tubular main body 52, a cutting head 54, a flex member 55, and a drillstring connection 56. While drillstring connection 56 is depicted as a rotary threaded connection, it should be understood by one of ordinary skill in the art that any method of connecting drilling assembly 50 with the remainder of the drillstring (not shown) may be employed, so long as rotational and axial loads may be transmitted therethrough. Furthermore, it should be understood that the term "drillstring" may be used to describe any apparatus or assembly that may be used to thrust and rotate drilling assembly 50. Particularly, the drillstring may comprise mud motors, bent subs, rotary steerable systems, drill pipe rotated from the surface, coiled tubing or any other drilling mechanism known to one of ordinary skill. Furthermore, it should be understood that the drillstring may include additional components (*e.g.* MWD/LWD tools, stabilizers, and weighted drill collars, etc.) as needed to perform various downhole tasks.

[0040] Cutting head 54 is depicted with a cutting structure 58 including a plurality of polycrystalline diamond compact ("PDC") cutters 60 and fluid nozzles 62. While drilling assembly 50 depicts a PDC cutting head 54, it should be understood that any cutting assembly known to one of ordinary skill in the art, including, but not limited to, roller-cone bits and impregnated natural diamond bits, may be used. As drilling assembly 50 is rotated and thrust into the formation, cutters 60 scrape and gouge away at the formation

while fluid nozzles 62 cool, lubricate, and wash cuttings away from cutting structure 58. Tubular main body 52 includes a plurality of axial recesses 64 into which arm assemblies 66 are located. Arm assemblies 66 are configured to extend from a retracted (shown) position to an extended position (Figure 11) when cutting elements 68 and stabilizer pads 70 of arm assemblies are to be engaged with the formation.

[0041] Arm assemblies 66 travel from their retracted position to their extended position along a plurality of grooves 72 within the wall of axial recesses 64. Corresponding grooves (73 of Figure 14) along the outer profile of arm assemblies 66 engage grooves 72 and guide arm assemblies 66 as they traverse in and out of axial recesses 64. While three arm assemblies 66 are depicted in figures of the present disclosure, it should be understood that any number of arm assemblies 66 may be employed, from a single arm assembly 66 to as many arm assemblies 66 as the size and geometry of main body 52 may accommodate. Furthermore, while each arm assembly 66 is depicted with both stabilizer pads 70 and cutting elements 68, it should be understood that arm assemblies 66 may include stabilizer pads 70, cutting elements 68, or a combination thereof in any proportion appropriate for the type of operation to be performed. Additionally, arm assembly 66 may include various sensors, measurement devices, or any other type of equipment desirably retractable and extendable from and against the borehole upon demand.

[0042] In operation, cutting structure 58 is designed and sized to cut a pilot bore, or a bore that is large enough to allow drilling assembly 50 in its retracted (Figure 1) state and remaining components of the drillstring to pass therethrough. In circumstances where the borehole is to be extended below a string of casing, the geometry and size of cutting structure 58 and main body 52 is such that entire drilling assembly 50 may pass clear of the casing string without becoming stuck. Once clear of the casing string or when a larger diameter borehole is desired, arm assemblies 66 are extended and cutting elements 68 disposed thereupon (in conjunction with stabilizer pads 70) underream the pilot bore to the final gauge diameter.

[0043] Preferably, drilling assembly 50 uses hydraulic energy to extend arm assemblies 66 from and into axial recesses 64 within main body 52. Drilling fluid is a necessary component of virtually all drilling operations and is delivered downhole from the surface at elevated pressures through a bore of the drillstring. Similarly, drilling assembly 50 includes a through bore 74, through which drilling fluids flow through drillstring connection 56 and main body 52 and out fluid nozzles 62 of cutting head 54 to lubricate cutters 60. As with other downhole drilling devices, the fluid exiting the bore at the bottom of the drillstring returns to the surface along an annulus formed between the borehole and the outer profile of the drillstring and any tools attached thereto.

[0044] Because of flow restrictions and differential areas between the bore and the annulus of drillstring components, the annulus return pressure is typically significantly lower than the bore supply pressure. This differential pressure between the bore and annulus is referred to as the pressure drop across the drillstring. Therefore, for every drillstring configuration, a characteristic pressure drop exists that may be measured and monitored at the surface. As such, if leaks in drill pipe connections, changes in the drillstring flowpath, or clogs within fluid pathways emerge, an operator monitoring the drillstring pressure drop from the surface will notice a change and may take action if necessary.

[0045] Similarly, drilling assembly 50 will desirably exhibit characteristic pressure drop profiles at various stages of operation downhole. When drilling with arm assemblies 66 in their retracted state within axial recesses 64, drilling assembly 50 will exhibit a pressure drop profile corresponding to that retracted state. When the operator desires to extend arm assemblies 66, the pressure and/or flow rate of drilling fluids flowing through bore 74 are increased to exceed a predetermined activation level. Once the activation level is exceeded, a flow switch activates a mechanism that will extend arm assemblies 66. Following such activation, a portion of the drilling fluids are diverted from through bore 74 of main body 52 to the annulus through a plurality of nozzles 76 located adjacent to axial recesses 64. As drilling fluids begin flowing through nozzles 76, the characteristic pressure drop of drilling assembly 50 changes to an intermediate profile such that the operator at the surface is aware the flow switch is activated and

underreaming has begun. Once arm assemblies 66 are fully extended, drilling assembly 50 is desirably constructed such that additional flow through an indication nozzle (77 of Figure 3) results and another pressure drop profile corresponding to the extended state is exhibited. When the drilling assembly 50 exhibits the expanded characteristic pressure drop profile, an operator monitoring at the surface is aware that arm assemblies 66 have fully extended. Additionally, it is desirable that the intermediate pressure drop profile of drilling fluids remains constant throughout the extension of arm assemblies, such that the surface operator observes a step-plateau change in pressure drop profile for drilling assembly 50.

[0046] When retraction of arm assemblies 66 is desired, the operator reduces (or completely cuts off) the pressure and/or flow rate of drilling fluids through bore 74 to a level below a predetermined reset level. Once decreased to the reset level, internal biasing mechanisms retract arm assemblies 66 and shut off flow between bore 74 and nozzles 76 and 77. Alternatively, the flow of drilling fluids through bore 74 can be cut off altogether. Following retraction, flow through nozzles 76 is halted and the operator may again observe the characteristic pressure drop profile associated with the retracted state across drilling assembly 50 and know that arm assemblies 66 are fully retracted. As with the extension process, an intermediate pressure drop profile will be observed while arm assemblies 66 are in the process of retracting, but not fully retracted. Once the operator observes the "retracted" characteristic pressure drop, they may proceed to raise the pressure and/or flow rate of drilling fluids through drilling assembly 50 up to the activation level without concern for extending arm assemblies 66.

[0047] Former flow switch mechanisms, particularly those employing shear members, do not have the ability to return to their original state following activation. As such, devices (e.g., expandable reamers, stabilizers, and drill bits) employing such mechanisms must be returned to the surface for re-configuration before they may be used up to their activation levels again without undesired activation of their components. Specifically, in the case of shear members, once ruptured, they must be replaced as they may be re-activated with even minimal pressure flows therethrough extending their components. Therefore, in circumstances where pressures are accidentally raised above the activation level, the

device must be retrieved and re-manufactured before operations may continue at pressure without extension. In contrast, flow switches in accordance with embodiments of the present invention allow the operator to back off pressure and let the device reset itself, thereby saving costly hours and expense to the drilling contractor. Once reset, elevated pressure flows will not affect arm assemblies 66 until the activation level is again exceeded.

[0048] Referring generally to Figures 1-10, an embodiment of drilling assembly 50 will be described in further detail. In Figure 1A, a close up view of the distal end of drilling assembly 50 detailing a flow switch 80 is shown. Figure 2 is an end view drawing of the distal end of drilling assembly 50 indicating the sectional view of Figures 1 and 1A at line 1-1. Similarly, Figure 3 is an alternative sectional view of the distal end of drilling assembly 50 taken along line 3-3 of Figure 2. Figure 4 is an enlarged view of a portion of flow switch 80 of drilling assembly indicated by item 4 on Figures 1 and 1A. Figure 5 is an enlarged view of a portion of drilling assembly indicated by item 5 on Figures 1 and 1A. Figure 6 is a sectional view of drilling assembly 50 taken at line 6-6 in figures 1 and 1A. Figure 7 is a sectional view of drilling assembly 50 taken at line 7-7 in Figures 1 and 1A. Figure 8 is a sectional view of drilling assembly 50 taken at line 8-8 in Figures 1 and 1A. Figure 9 is a sectional view of drilling assembly 50 taken at line 9-9 in Figures 1 and 1A. Figure 10 is a sectional view of drilling assembly 50 taken at line 10-10 in Figures 1 and 1A.

[0049] Referring now to Figures 1, 1A, 3, 4, 6, and 8-10 together, flow switch 80 includes a flow mandrel 82, a nozzle 84, and a piston 86. Mandrel 82 is housed within through bore 74 of main body 52, includes a central bore 78, and is anchored in place at its proximal end by a lock nut 88 in combination with a spring retainer 90. A spring 92 surrounds mandrel 82 and extends from spring retainer 90 to a spring sleeve 94. Spring sleeve 94 is connected at its distal end to a spring drive ring 96 positioned circumferentially around mandrel 82. Spring drive ring 96 includes a plurality of radial yoke-like extensions 98 engaged within arm assemblies 66. As such, when arm assemblies 66 are translated along grooves 72 in wall of axial recesses 64, radial extensions 98 and spring drive ring 96 thrust spring sleeve 94 upstream toward spring

retainer 90, compressing spring 92 in the process. Yoke-like construction enables spring drive ring 96 to be located underneath and within arm assemblies 66, thereby conserving axial length of drilling assembly 50. When arm assemblies 66 are fully extended, an arm stop ring 99 prevents over-extension. Therefore, when a force thrusting arm assemblies 66 into engagement is removed, compressed spring 92 in conjunction with spring sleeve 94, drive ring 96 and radial extensions 98 return arm assemblies 66 to their retracted (shown), equilibrium state.

[0050] Referring specifically to Figures 1A, 3, 4, 8, and 9, flow switch 80 includes a flow tube 100 slidably engaged within the distal end of mandrel 82 and a proximal end of a piston stop 102. Flow tube 100 includes nozzle 84 at its proximal end and abuts a spring 104 at its distal end. Spring 104 extends within piston stop 102 from flow tube 100 to a spring retainer 106 that is slidably engaged within piston stop 102 between a steady state position (shown) and a stop ring 108. Toggles 110 pivotally secured to piston stop 102, rotate about hinge pins 112. Toggles 110 prevent spring retainer 106 from sliding within piston stop 102 until piston 86 moves from its retracted (shown) state to its extended state as a result of increases in hydraulic fluid pressure thereagainst. To accomplish this, inward ends 113 of toggles 110 are positioned within apertures 114 of spring retainer 106 and outward ends 116 of toggles engage the end of piston 86 as shown in Figure 4. With piston 86 fully retracted, toggles 110 are unable to pivot about pins 112, such that apertures 114 of spring retainer 106 are unable to displace inward ends 113 of toggles 110. As a result of these restrictions, spring retainer 106 is unable to be displaced within piston stop 102 in the direction of stop ring 108, thereby maintaining the compressive load in spring 104.

[0051] Referring now to Figures 1, 1A, 3, 5, 7, and 13, an embodiment of extension assembly 120 will be described. Extension assembly 120 includes an arm drive ring 122, a plurality of arm drive sleeves 124, and a plurality of nozzles 76. When piston 86 is thrust upstream, the motion and force applied to piston 86 is, in turn, transferred to arm drive ring 122. Arm drive ring 122 is circumferentially disposed around piston 86 which is circumferentially disposed around mandrel 82 and within main body 52. As piston 86 thrusts arm drive ring 122 upstream towards drillstring connection 56, arm drive sleeves

124 surrounding radial extensions 126 of drive ring 122 engage distal ends of arm assemblies 66. As arm assemblies 66 are engaged by drive sleeves 124, they are thrust upstream and radially extended along grooves 72 of axial recesses 64. Furthermore, as piston 86 and arm drive ring 122 thrust arm assemblies 66 upstream, radial extensions 98 of spring drive ring 96 compress spring 92 surrounding mandrel 82. Once the thrusting force is removed from piston 86 and arm assemblies 66, spring drive ring 96 will act under the compressed load of spring 92 and retract arm assemblies 66.

[0052] Referring now to Figures 1, 1A, and 3-5, the operation of drilling assembly 50 will now be described. While in the retracted position (shown), drilling fluids flow through drilling assembly 50 from the drillstring through bore 74 and bore 78 of mandrel 82. A seal 128 located between spring retainer 90 and main body 52 prevents fluids from bypassing bore 78 of mandrel 82 and escaping through axial recesses 64. After flowing through bore 78, drilling fluids encounter nozzle 84 where they are accelerated and continue flowing through respective bores 130, 132, 134, and 136 of flow tube 100, piston stop 102, spring retainer 106, and stop ring 108. After exiting bore 136 of stop ring 108, the drilling fluids flow to a plenum 138 within cutting head 54, where they communicate with and flow through nozzles 62 adjacent to cutting structure 58.

[0053] Because of various sealing mechanisms, drilling fluid is not able to bypass fluid plenum 138 and nozzles 62 when drilling assembly 50 is in its retracted position. Particularly, a seal in groove 140 between mandrel 82 and piston stop 102 prevents fluid from escaping into a chamber 142 prematurely. As chamber 142 is in communication with the annulus through nozzles 76, arm drive ring 122, and a plurality of ports 144, seal in groove 140 prevents loss of drilling fluid pressure when drilling assembly 50 is retracted. Next, upset portion 146 of piston stop 102 forms a seal with inner diameter of piston 86 so that a chamber 148 formed between piston 86 and piston stop 102 cannot communicate with chamber 142. Additionally, a hydraulic seal in groove 147 isolates plenum 138 inside cutting head 54 from a chamber 149 in communication with chamber 148. Furthermore, seal grooves 152 and 153 containing wipers and seals (not shown), prevent drilling fluid from escaping between piston 86 and main body 52.

[0054] Finally, cutting head 54 is shown attached to main body 52 by means of an oilfield rotary threaded connection 150 approximately between chambers 148 and 149. Because such rotary connections are generally fluid-tight, substantially no drilling fluids escape drilling assembly 50 other than through nozzles 62 when in the retracted state. While a detachable rotary threaded connection 150 is shown, it should be understood that an integrally formed (*e.g.* welded, machined, etc.) cutting head 54 may also be employed. However, rotary threaded cutting head 54 has the advantage of being removable should cutting head 54 require replacement. Furthermore, because a reduced-height connection is used between cutting head 54 and the rest of drilling assembly 50, cutting head 54 is substantially unitary with expandable cutters 68 and stabilizers 70 such that an axial length therebetween is minimized. A reduced axial length (*e.g.* between 1-5 times the cutting diameter of cutting head 54) between the trailing edge of cutting head 54 and the leading edge of retracted arm assemblies 66 may be useful in reducing side loads experienced by cutters 68 during operation. Having cutting structures of cutter body 54 proximate and disposed upon the same tool as expandable cutters 68 allows cutting geometry 58 of cutting head 54 to be optimized (if desired) to correspond with the arrangement of cutter elements 68 on arm assemblies 66 to maximize cutting efficiency and durability while reducing vibrations within drilling assembly 50.

[0055] Referring now to Figures 11, 12, 15, and 16, drilling assembly 50 is shown in its fully extended state. When the drilling operator desires to extend arm assemblies 66, the pressure of drilling fluids flowing through the drillstring is increased to a point above a preselected activation value. The geometry of nozzle 84 within flow tube 100 and the spring constant of spring 104 within piston stop 102 are desirably selected to allow for displacement of flow tube 100 within piston stop 102 at the selected activation value. Once reached, fluid flowing across nozzle 84 at the activation pressure creates a resultant force large enough to displace flow tube 100 within mandrel 82 and piston stop 102 against spring 104. Concealed apertures 160 within distal end of mandrel 82, in communication with chamber 142 become exposed as flow tube 100 is displaced downstream. With apertures 160 exposed, drilling fluids within bore 78 of mandrel 82 communicate with nozzle 76 through ports 144 and chamber 142. At this point, the

characteristic pressure drop of drilling assembly 50 changes to an intermediate profile, detectable at the surface by an operator. Once the intermediate profile is observed, the operator knows the activation of drilling assembly 50 has begun as with apertures 160 exposed, fluid is able to escape from bore 78 to the annulus through nozzles 76.

[0056] To fully extend arm assemblies 66 of drilling assembly 50, the pressure of drilling fluids may be maintained or increased so that the pressure across piston 86 between seals 152 and 153 is enough to create enough resultant force in piston to overcome the force of spring 92. As piston 86 is thrust upstream by fluid pressure in chamber 142 acting across seals 152 and 153, the distal end of piston 86 pulls away from outward ends 116 of toggles 110. With piston 86 no longer restraining outward ends 113, toggles 110 pivot around pins 112 thereby allowing spring retainer 106 to be displaced within piston stop 102 until it contacts stop ring 108. With spring retainer 106 displaced into stop ring 108, the compressive load within spring 104 is reduced, thereby preventing flow tube 100 from oscillating back and forth within piston stop 102. Nonetheless, as arm assemblies 66 are thrust upstream by piston 86 in conjunction with drive ring 122, grooves 72 within wall of axial recesses 64 cooperate with corresponding grooves 73 to radially expand arm assemblies 66 until stop ring 99 is encountered as shown in Figure 11.

[0057] Referring specifically to Figure 11, the drilling assembly 50 is shown in the fully expanded state. As can be seen in Figure 11, with arms fully extended, the distal end of piston 86 is completely clear of portion 146 of piston stop 102. In this position, chambers 142, 148, and 149 are all in fluid communication with each other such that pressurized drilling fluids from bore 78 can communicate with them through apertures 160. Therefore, with arm assemblies 66 fully extended, an indication nozzle 77 (visible in Figure 3) in communication with chamber 149 is activated such that drilling fluids flowing through bore 78 may escape therethrough. Therefore, when fully activated, drilling assembly 50 will exhibit yet another characteristic pressure drop, one associated with the fully-expanded state. An operator at the surface will be able to observe the change in the pressure drop profile and will know that the drilling assembly 50 is ready to be operated in the extended state.

[0058] Of particular note, with spring retainer 106 thrust into stop ring 108, the amount of pressure required to maintain flow switch 80 in the fully open position is reduced as the amount of force required to overcome spring 104 is reduced. Therefore, when fully extended, the amount of pressure required to keep flow tube 100 compressed against spring 104 in order to expose apertures 160 is likewise reduced but, as a general rule, the higher pressures are typically maintained. As such, the pressure of drilling fluids necessary to keep arm assemblies 66 extended only needs to be sufficient to overcome the force of compressed spring 92.

[0059] When retraction of arm assemblies 66 is desired, the pressure of drilling fluids is reduced to a reset level (or cut-off completely) so that spring 92 retracts arm assemblies 66 through spring drive ring 96. The retraction of arm assemblies 66 thrusts piston 86 downstream such that it re-engages upset portion 146 of piston stop 102 and outward ends 116 of toggles 110. As such, spring retainer 106 is driven back to its original position and spring 104 likewise re-energized to thrust flow tube 100 upstream to cover apertures 160.

[0060] With arm assemblies 66 retracted, flow is again cut off to nozzles 76 and 77. Once retracted, the operator monitoring the pressure drop at the surface will be aware of the complete retraction of drilling assembly 50 when it exhibits the characteristic pressure drop associated with the retracted profile once again. If any debris or other matter is clogged within axial recesses 64, preventing the complete retraction of arm assemblies 66, the surface operator will be notified when the retracted pressure drop profile is not observed. In such a case the surface operator may attempt to cycle the drilling assembly 50 in an attempt to clear the obstruction. Once reset, the drilling assembly may be re-extended in the same manner as described above.

[0061] Referring now to Figures 17 and 18, an alternative arrangement for an arm assembly 180 is shown. Alternative arm assembly 180 includes an arm 182 having a cutting portion 184 and a stabilizer portion 186. As such, arm 182 translates from a retracted (Figure 17) position to an extended (Figure 18) position along a plurality of grooves 188 within a wall of an axial recess 190 of a drilling assembly. In some

circumstances, it is desirable for the cutting portion 184 of an arm assembly 180 to engage the borehole before stabilizer portion 186. Particularly, it has been observed that there is some difficulty in beginning a cut when stabilizer portion 186 and cutting portion 184 engage the formation simultaneously. Therefore, arm assembly 180 advantageously allows cutting portion 184 to engage the formation first by employing a radial configuration for grooves 188. Particularly, grooves 188 are constructed as concentric sections of circles having a common center 192 and a maximum radius 194. As such, when retracted within recess 190, arm 182 is positioned such that cutting portion 184 is extended slightly more outward than stabilizer portion 186. However, once extended, both cutting portion 184 and stabilizer portion 186 of arm 182 are at the same radial height.

[0062] Referring now to Figures 19 and 20, a second alternative arrangement for an arm assembly 200 is shown. Alternative arm assembly 200 includes two separate arms, a cutter arm 202 and a stabilizer arm 204, each extendable radially along its own set of linear grooves 206, and 208. As may be appreciated, the extension of cutter arm 202 ahead of stabilizer arm 204 is accomplished by having a steeper slope for stabilizer arm extension grooves 206 than cutter arm grooves 208. In addition, stabilizer arm 204 is installed in the arm pocket such that it is initially inboard of cutter arm 202. However, once extended, both cutter arm 202 and stabilizer arm 204 are at the same radial height. Therefore, cutter arm 202 will engage the formation before stabilizer arm 204.

[0063] Embodiments of the present invention described above have many advantages over the prior art. Particularly, the drilling assembly disclosed herein includes a bit, an underreamer, and a stabilizer within close axial proximity to one another. Advantageously, having an adjustable stabilizer proximate (e.g. axially spaced within 1-5 times the diameter of the pilot bit) to an underreamer prevents the underreamer from taking heavy side loads and assuming the role of a fulcrum in a directionally drilled wellbore. Having an adjustable stabilizer adjacent to the cutting structure of an underreamer prevents premature wear and damage to the cutting structure as a result of such side loading. Furthermore, having the pilot bit assembly proximate to the underreamer section further minimizes the fulcrum effect, thereby maximizing the life of

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the cutting structures of both the pilot bit and the underreamer. By making the pilot bit integral with the underreamer mechanism, the axial length between them is minimized.

[0064] Furthermore, the optional flex member located upstream of the stabilizer/underreamer mechanism enables larger build rates in directional drilling applications. The use of such a flex member is described by United States Patent Application Serial No. 11/334,707 (Publication No. 2007/6163810A1) entitled "Flexible Directional Drilling Apparatus and Method" filed on January 18, 2006 by inventors Lance Underwood and Charles Dewey, published June 19, 2007.

[0065] Depending on the geometry and type of equipment upstream of the flex member, the combination of the pilot bit, underreamer, and stabilizer may be treated together as a fulcrum in a directional drilling system, rather than each component as a single node in a flexible string. As such, additional expandable stabilizers, including those of the type described in U.S. Patent No. 6,732,817, may be located upstream of the drilling assembly to implicate a desired build angle in the trajectory of the drilling assembly.

[0066] Furthermore, the drilling assembly disclosed herein has the aforementioned benefit of distinct changes in the pressure drop profile to indicate the expansion status of the arm assemblies. Particularly, using the drilling assembly disclosed herein, a driller will be able to know, with some degree of accuracy, precisely when the arms are retracted, when they are fully extended, and when they are in transition from retracted to extended. As such, the operator will no longer have to guess or estimate what state the underreamer or stabilizer is in.

[0067] Finally, as mentioned above, the drilling assembly disclosed herein employs an actuation mechanism that not only indicates the status of actuation, but is also capable of being completely reset to its pre-activation state. Particularly, as outlined above, former actuation mechanisms could not be deactivated once activated, thereby reducing the flexibility of the bottom hole apparatus following activation. In contrast, using the actuation mechanism disclosed herein, downhole tools may return to their original state when their activated state is no longer needed. Therefore, if, after drilling an

underreamed hole for a particular distance, a non-underreamed borehole is desired, the drilling assembly of the present invention may drill such a borehole without the need to return to the surface for resetting first. While a hydraulic actuation mechanism and the benefits thereof have been described in detail, it should not be understood by one of ordinary skill in the art that such a mechanism is a required component of the drilling system disclosed herein. Alternatively, for certain circumstances, a simplified shear member activation mechanism may be used instead.

[0068] While preferred embodiments of this invention have been shown and described, modifications thereof may be made by one skilled in the art without departing from the spirit or teaching of this invention. The embodiments described herein are exemplary only and are not limiting. Many variations and modifications of the system and apparatus are possible and are within the scope of the invention. Accordingly, the scope of protection is not limited to the embodiments described herein, but is only limited by the claims which follow, the scope of which shall include all equivalents of the subject matter of the claims.

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CLAIMS:

1. A switch to divert drilling fluids from a bore of a downhole apparatus, the switch comprising:

the bore providing an aperture in communication
5 with a device to be activated;

a flow tube slidably engaged within the bore isolating the aperture from the drilling fluids when in a deactivated position;

the aperture in communication with drilling fluids
10 in the bore when the flow tube is in an activated position;

a biasing member extending between the flow tube and a spring retainer within the bore, the biasing member configured to bias the flow tube into the deactivated position;

15 a nozzle disposed within the flow tube, the nozzle configured to transmit a force to the flow tube corresponding to a pressure of drilling fluids flowing therethrough; and

the force displacing the flow tube into the
20 activated position when the pressure of the drilling fluids flowing therethrough exceed an activation value.

2. The switch of claim 1, wherein the spring retainer is slidably engaged within the bore.

3. The switch of claim 2, wherein a piston engaged
25 with the spring retainer is configured to retract when the pressure of the drilling fluids flowing through the bore of the downhole apparatus falls below a reset value.

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4. The switch of claim 1, wherein the nozzle and biasing member are replaceable to change the activation value.

REPLACEMENT SHEET

1/14

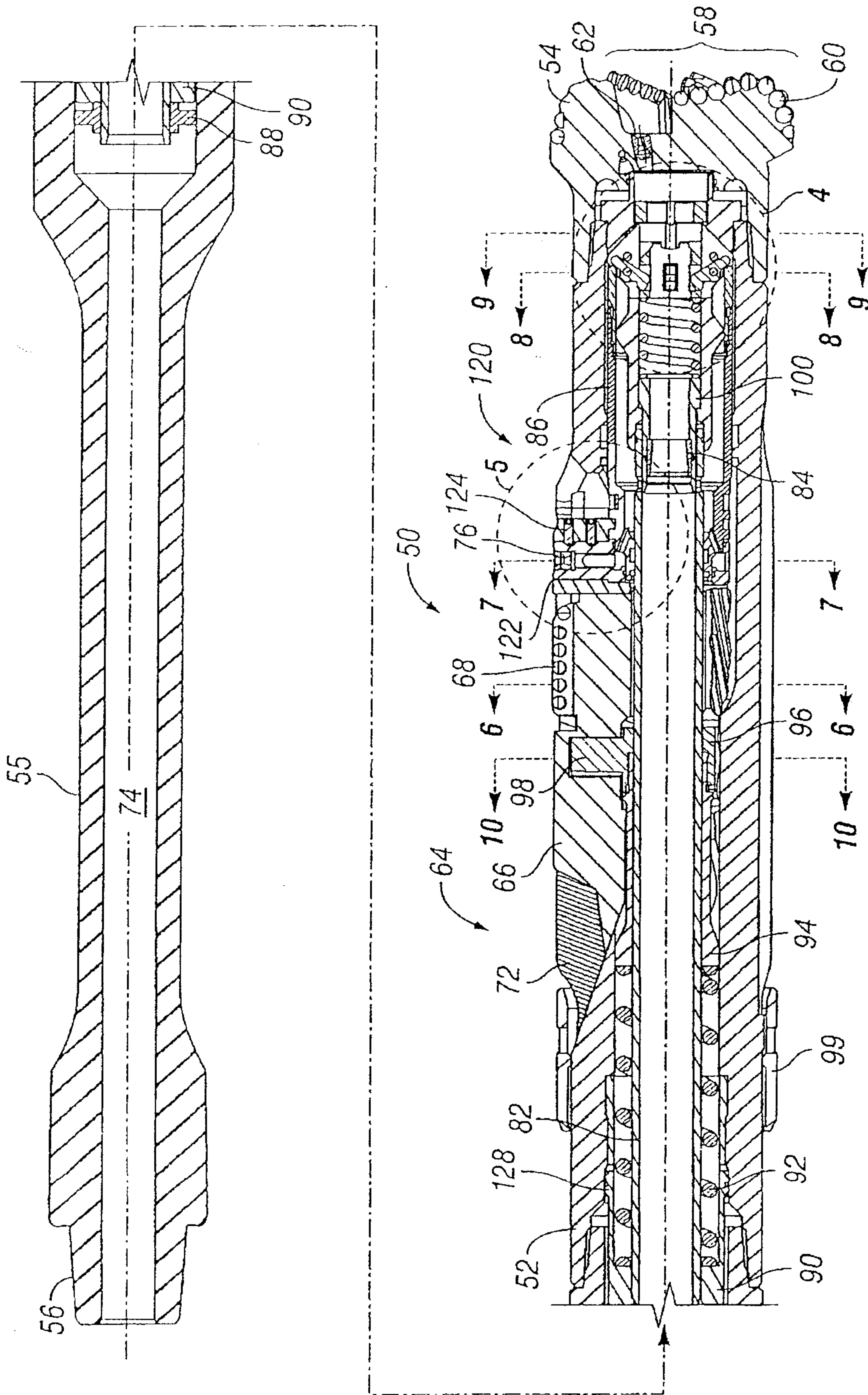


FIG. 1

REPLACEMENT SHEET

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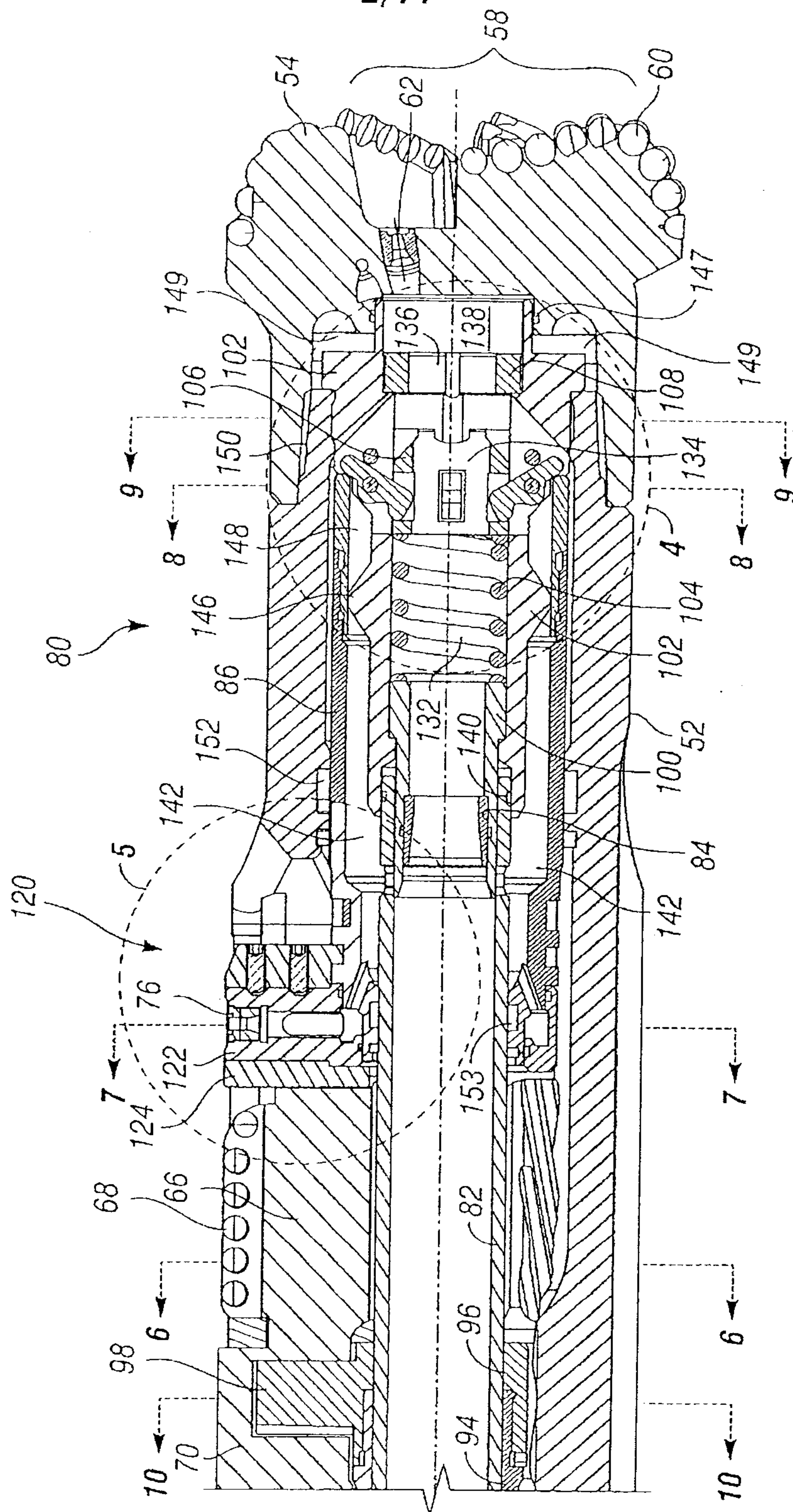


FIG. 1A

REPLACEMENT SHEET

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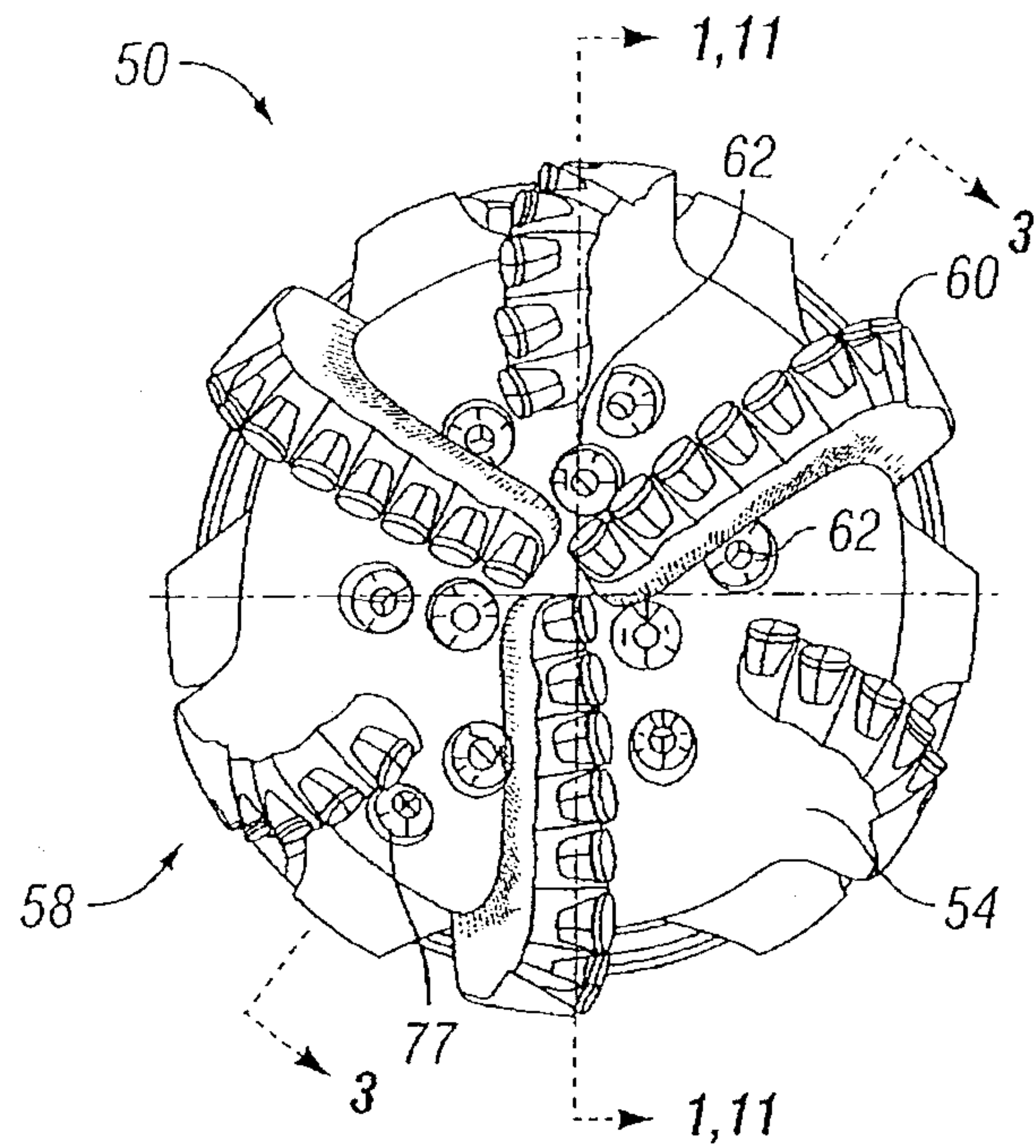


FIG. 2

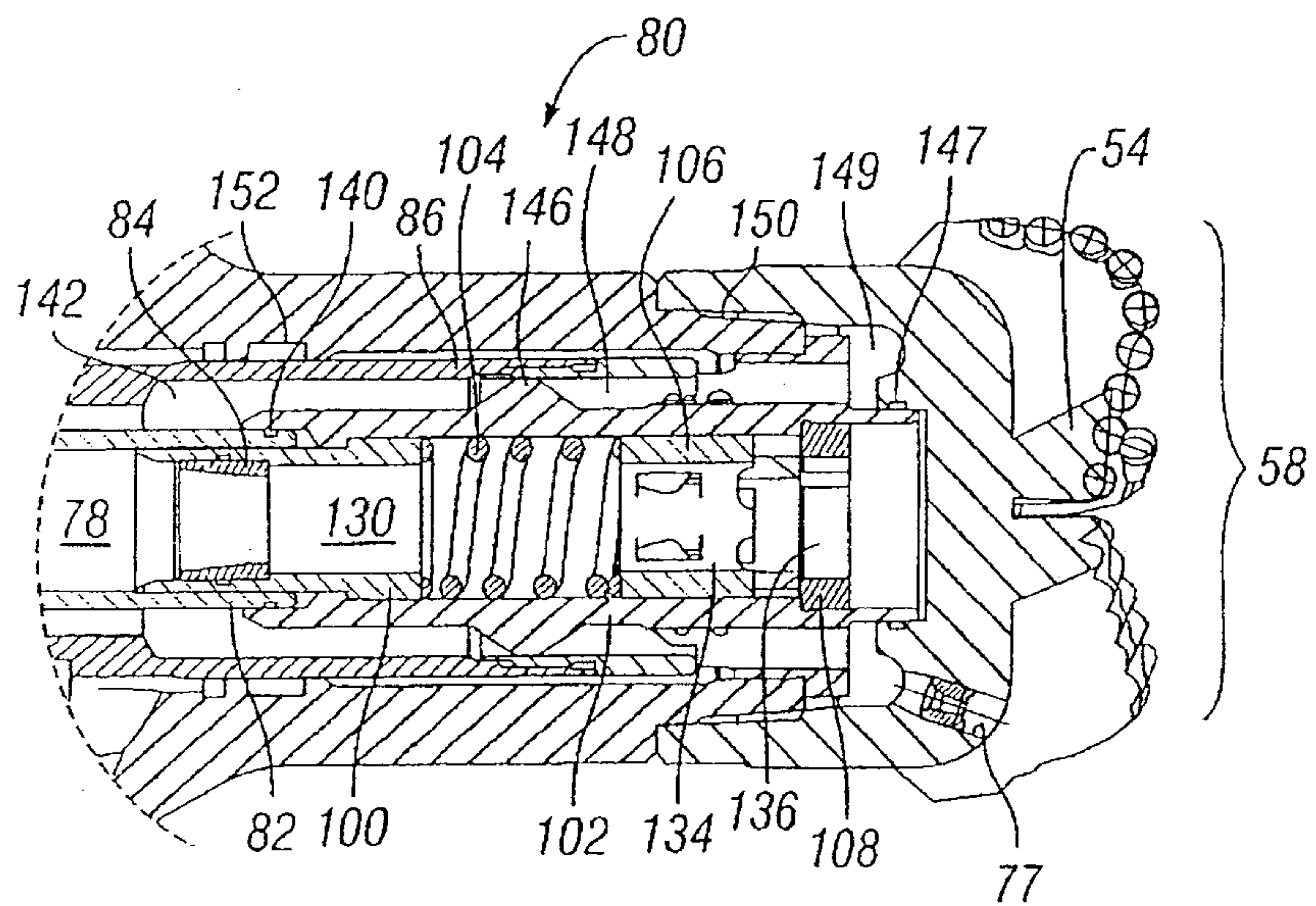


FIG. 3

REPLACEMENT SHEET

4/14

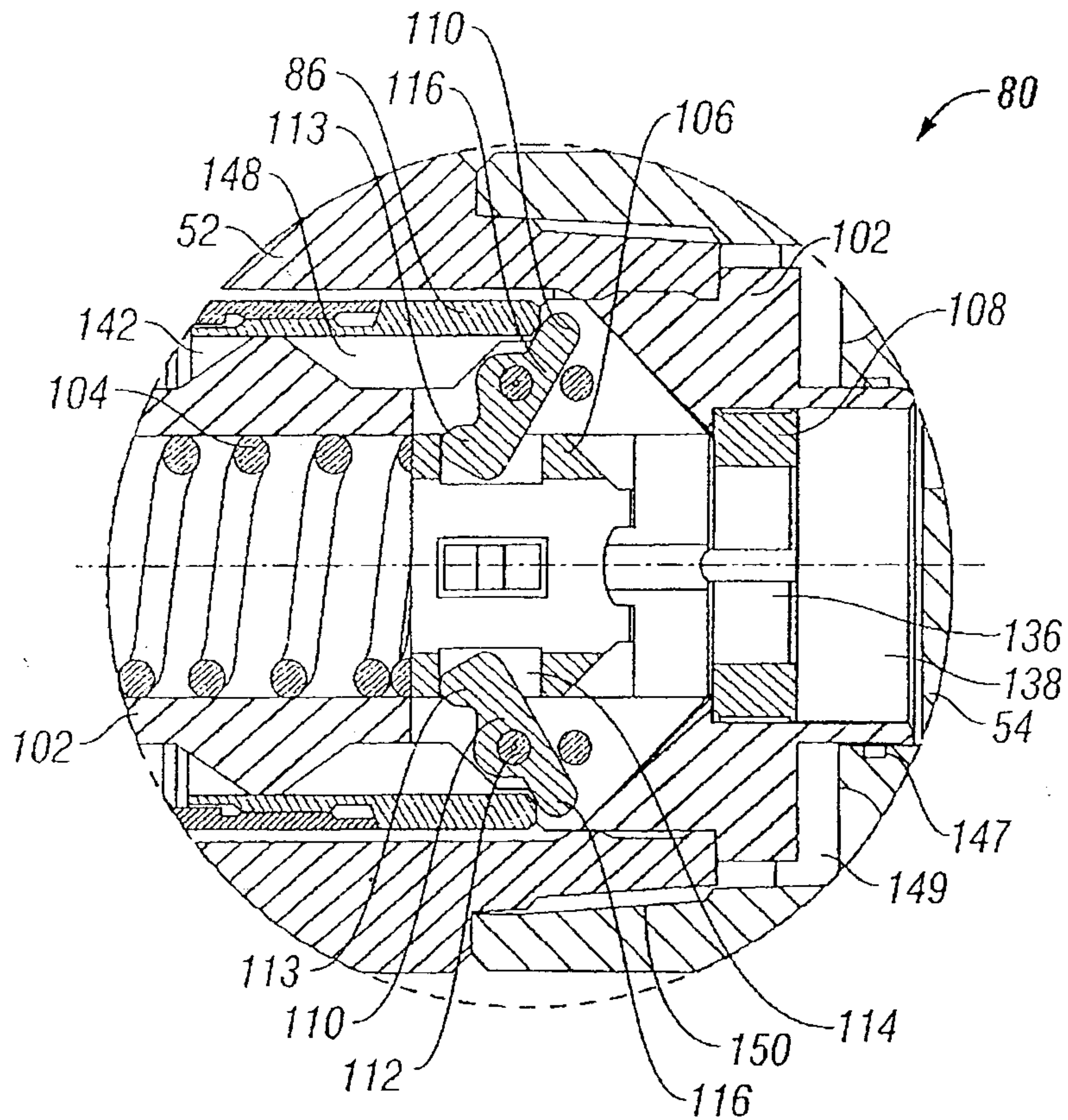


FIG. 4

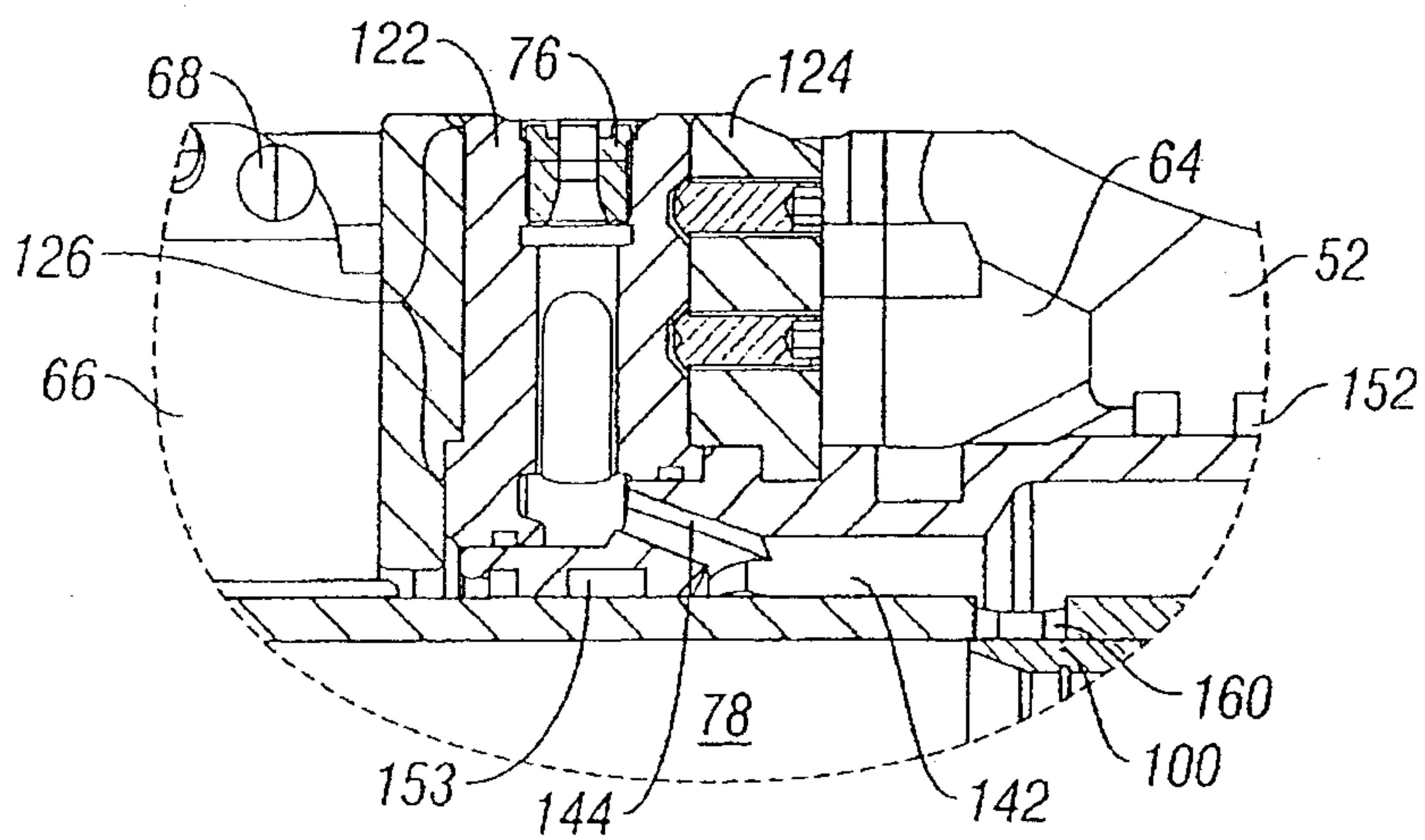


FIG. 5

REPLACEMENT SHEET

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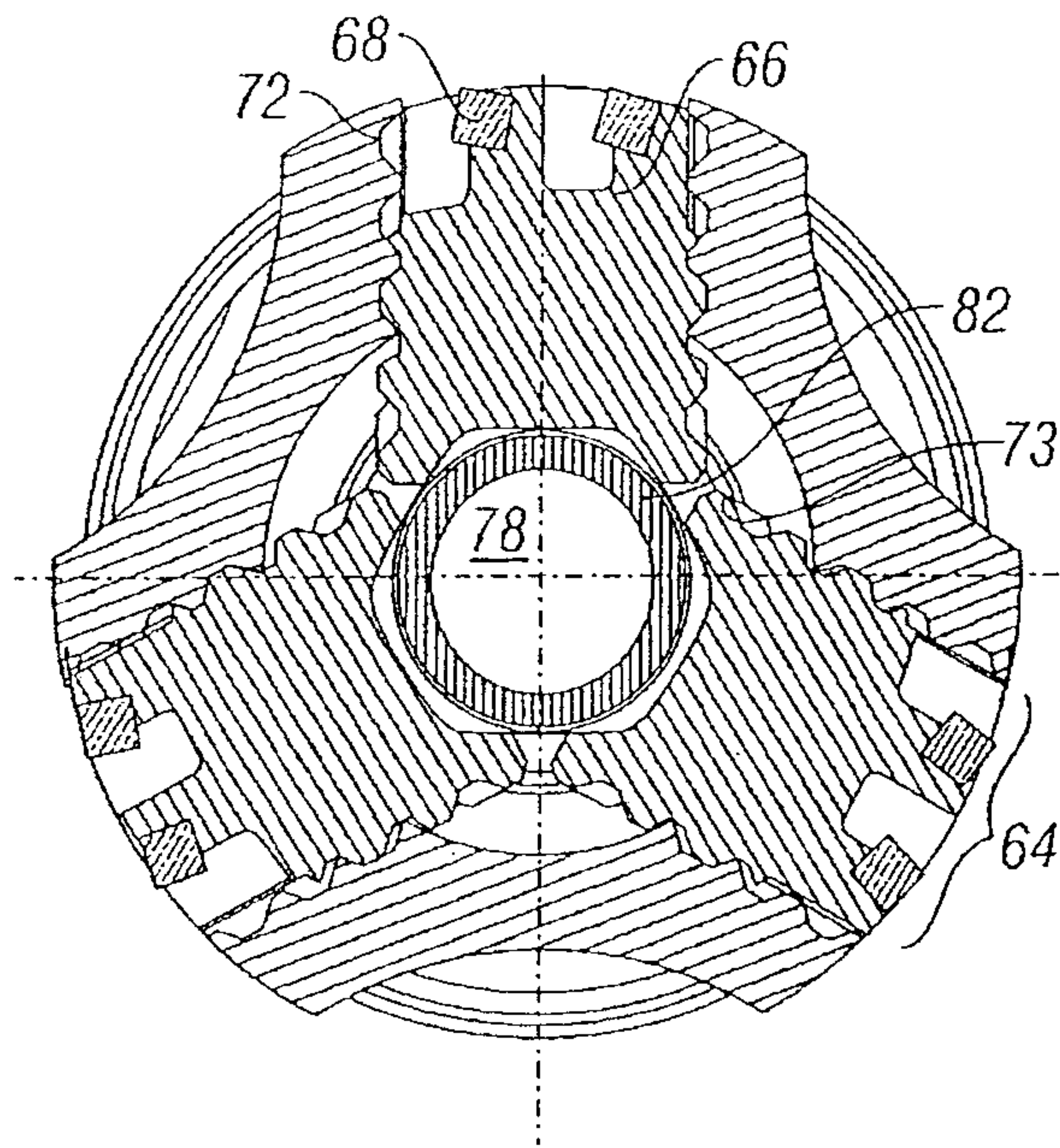


FIG. 6

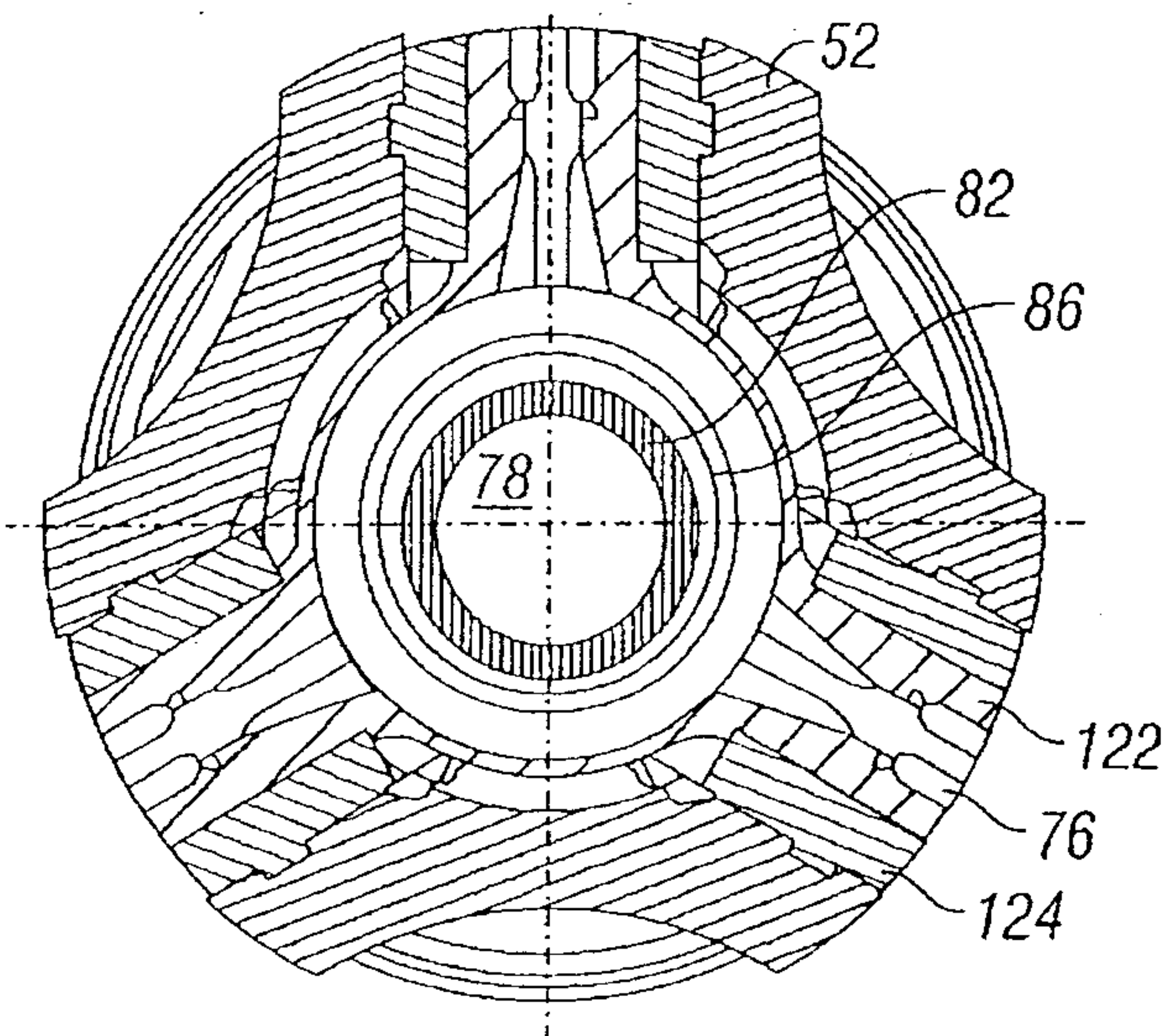


FIG. 7

REPLACEMENT SHEET

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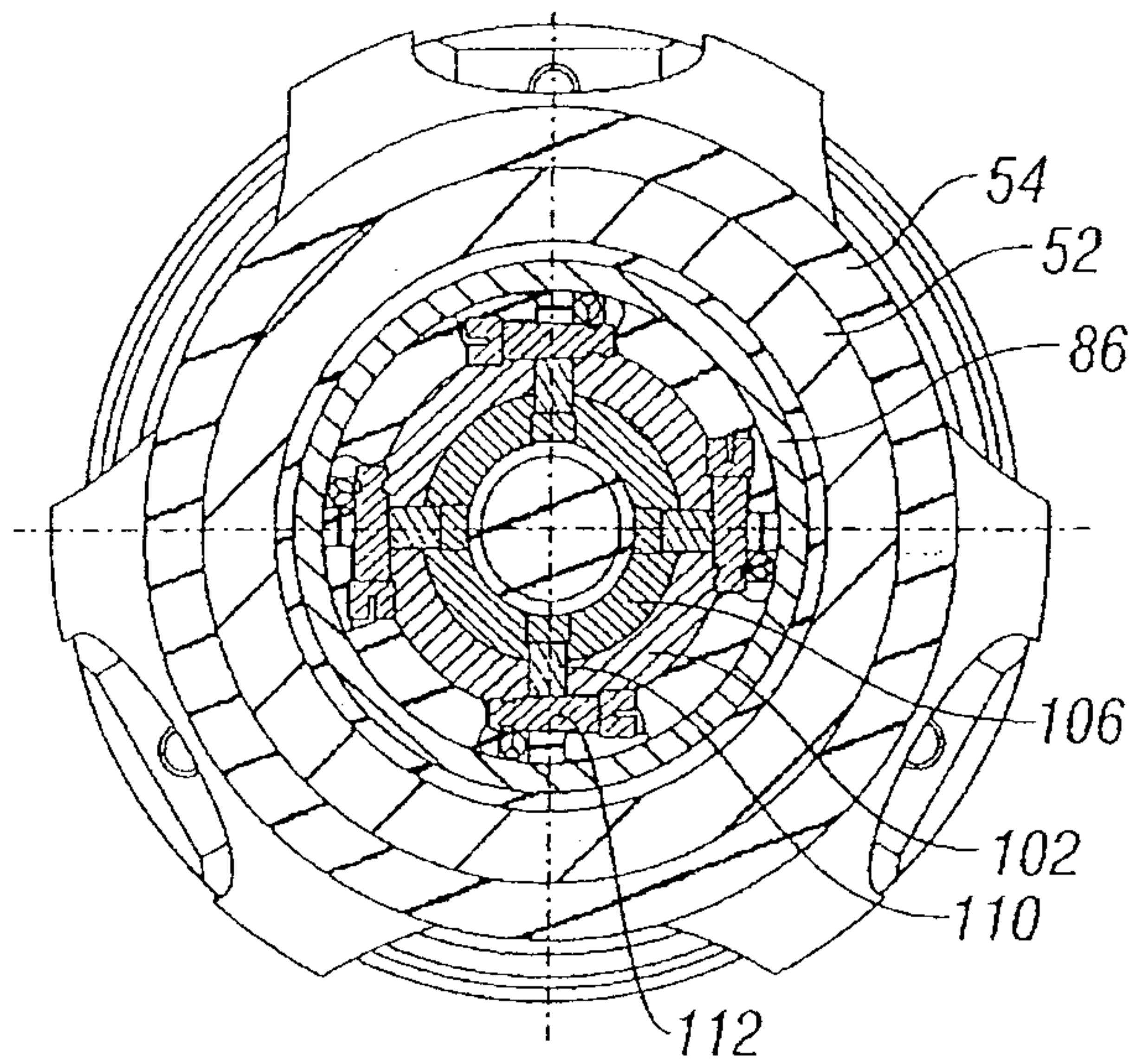


FIG. 8

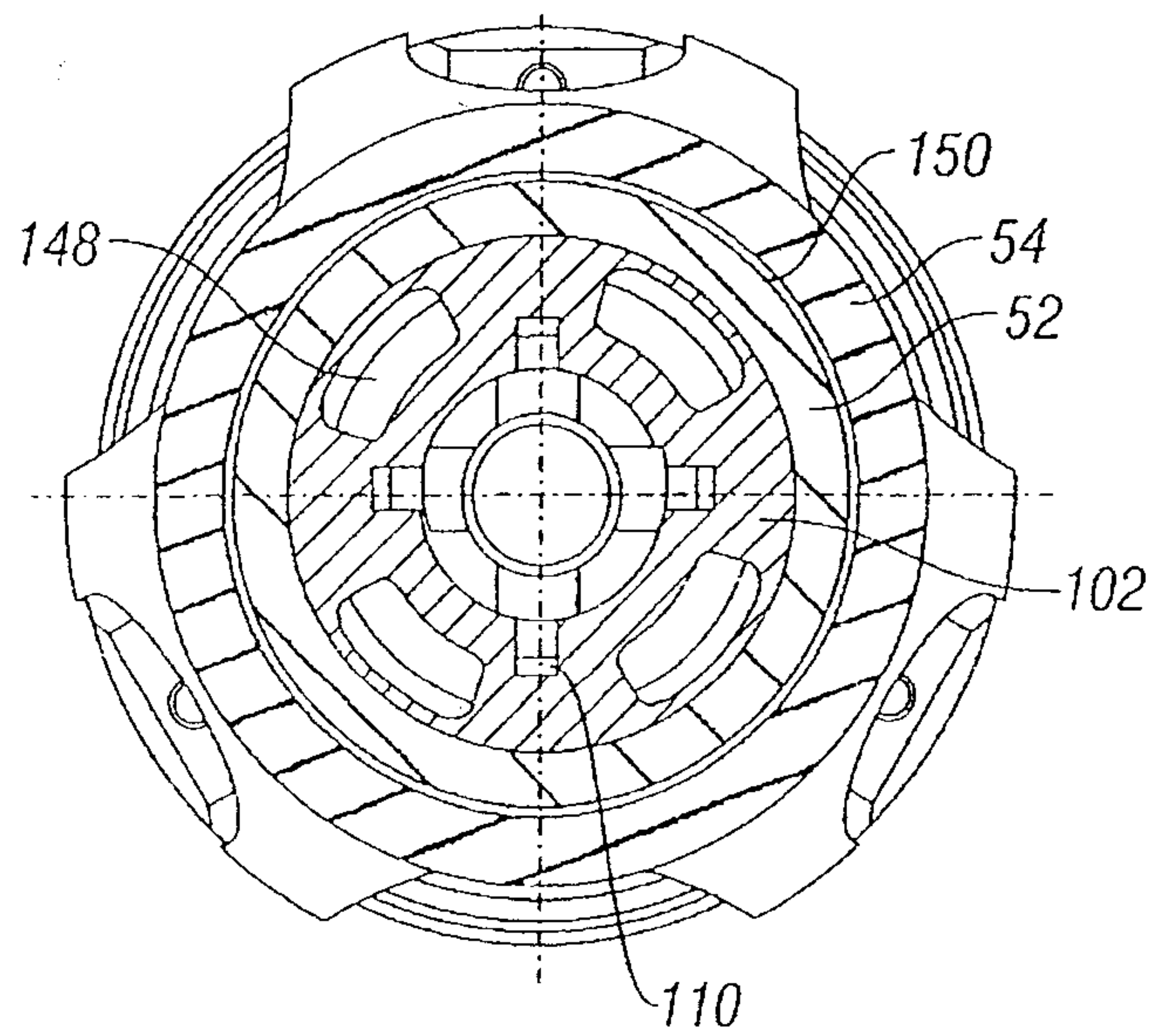


FIG. 9

REPLACEMENT SHEET

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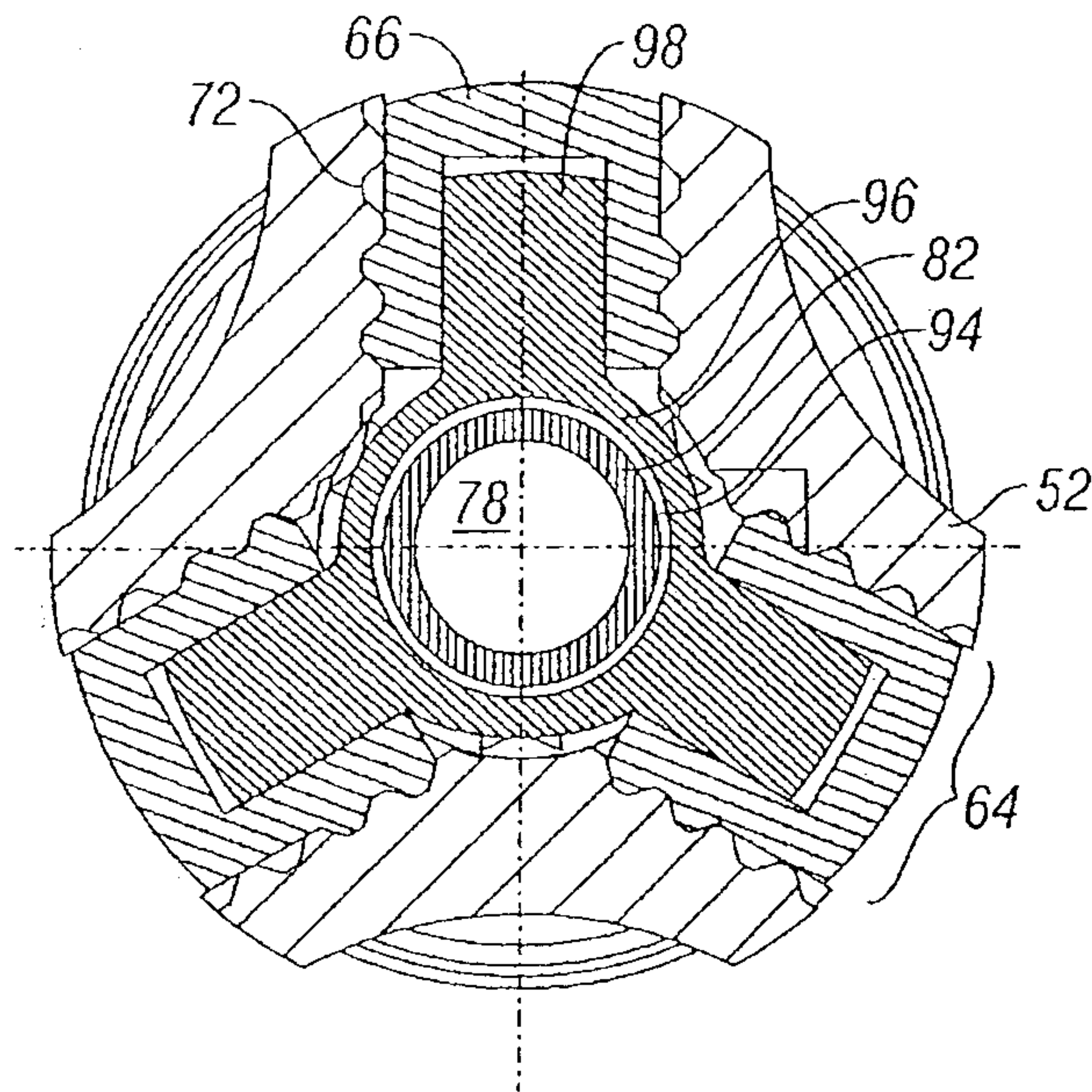


FIG. 10

REPLACEMENT SHEET

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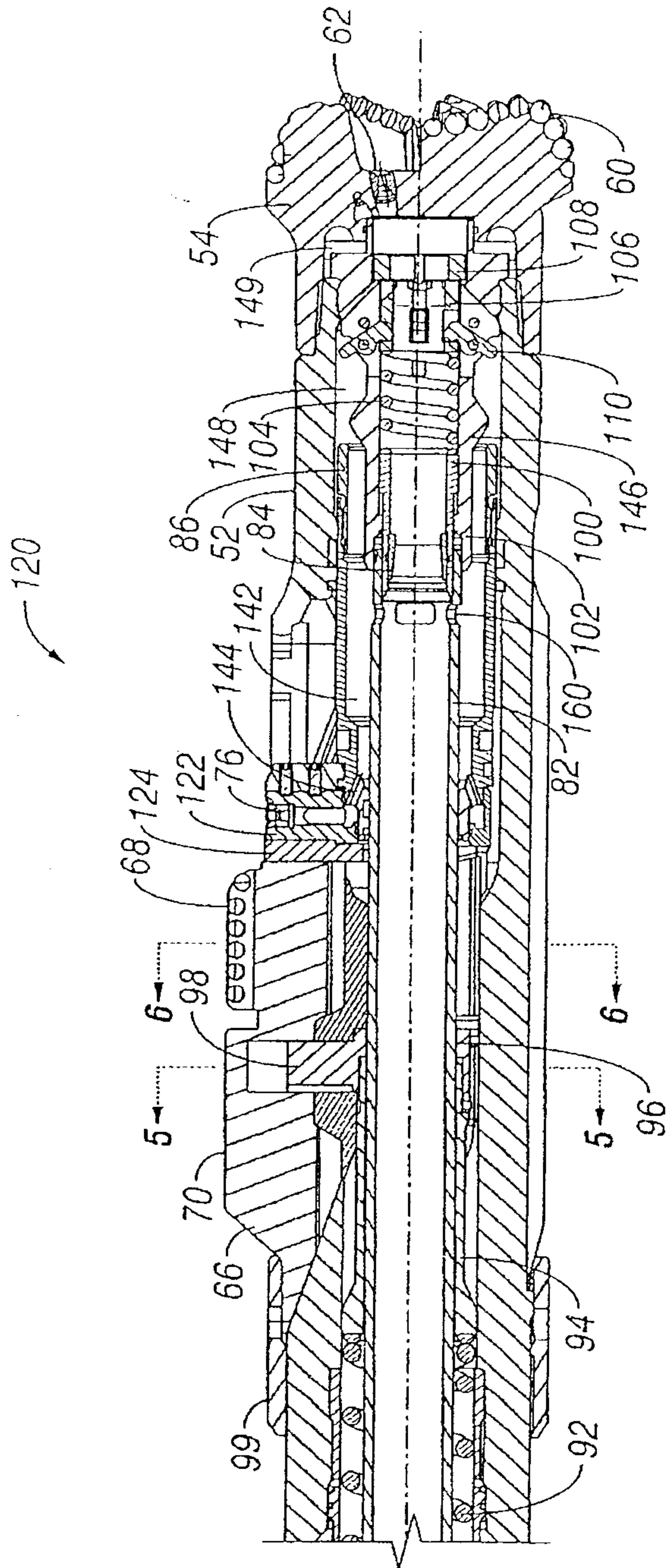


FIG. 11

REPLACEMENT SHEET

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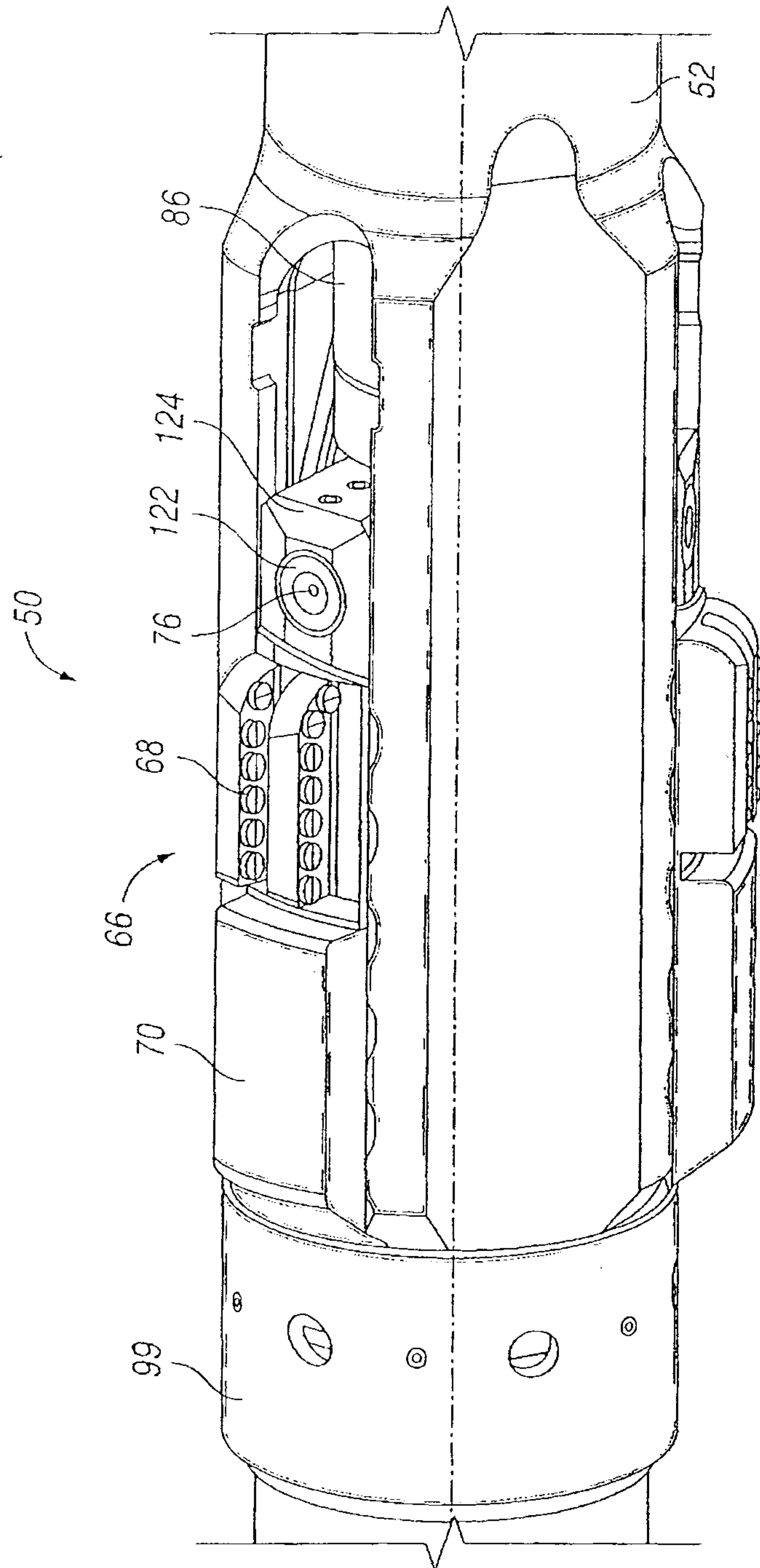


FIG. 12

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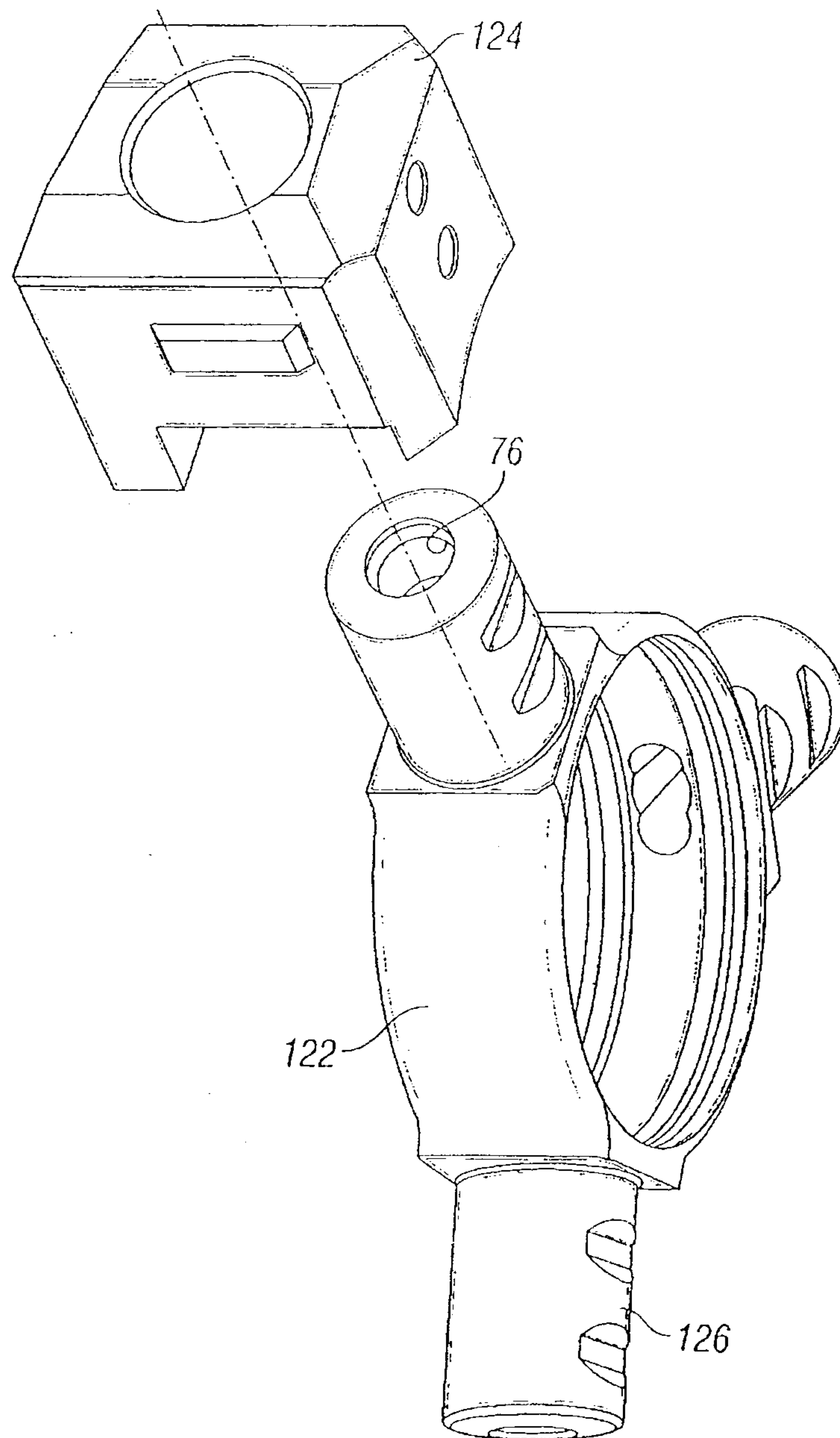


FIG. 13

REPLACEMENT SHEET

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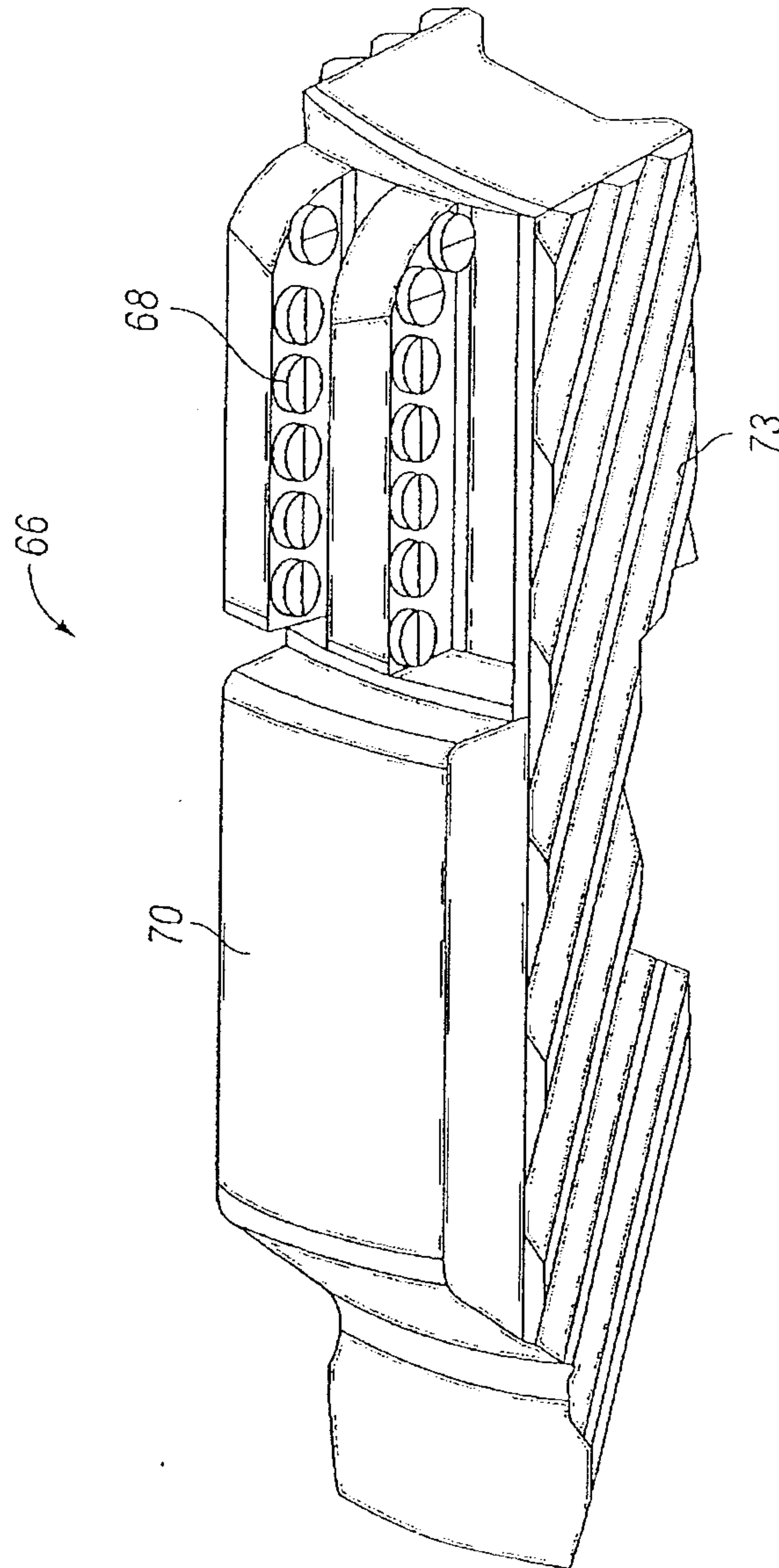


FIG. 14

REPLACEMENT SHEET

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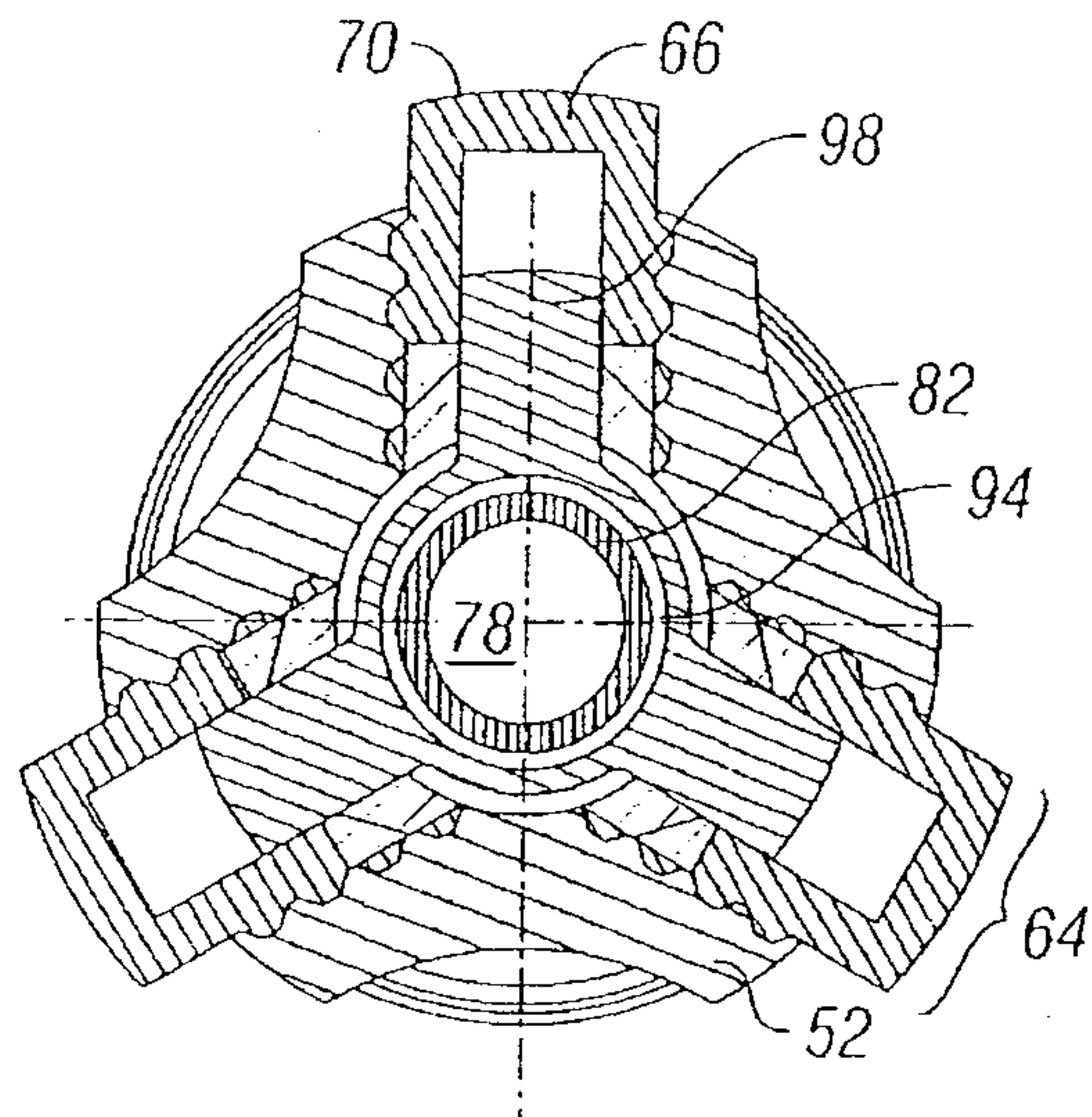


FIG. 15

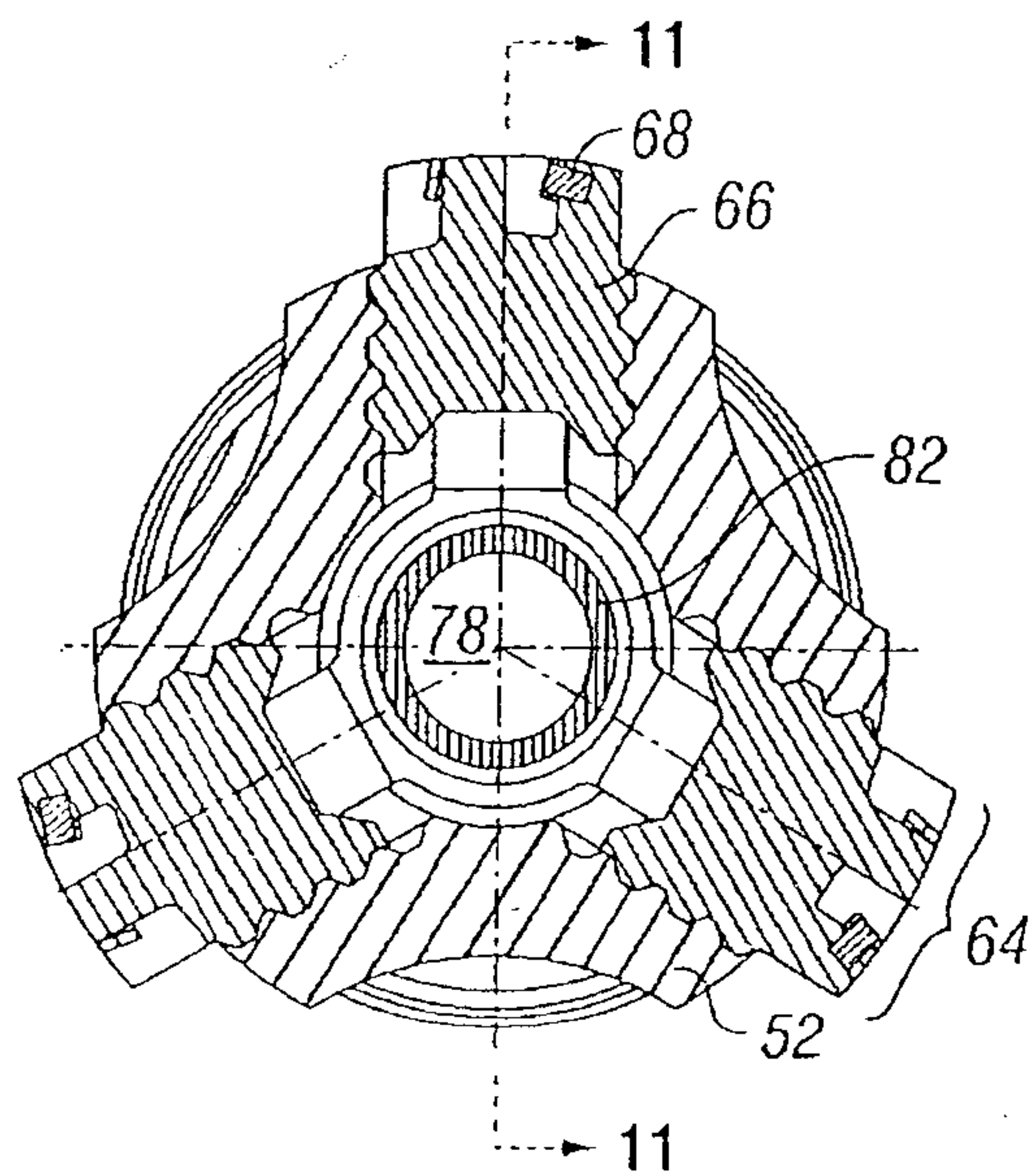


FIG. 16

REPLACEMENT SHEET

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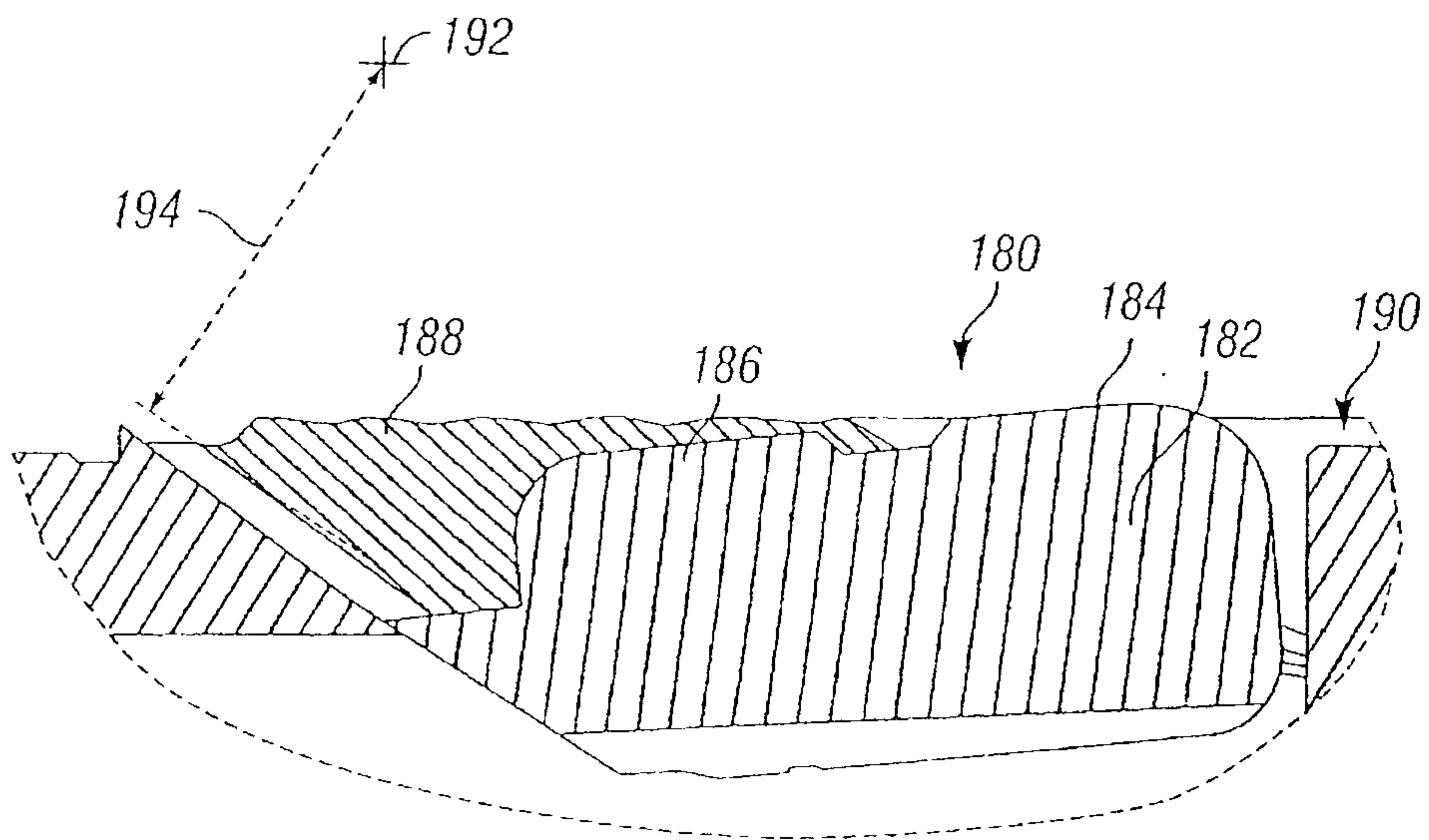


FIG. 17

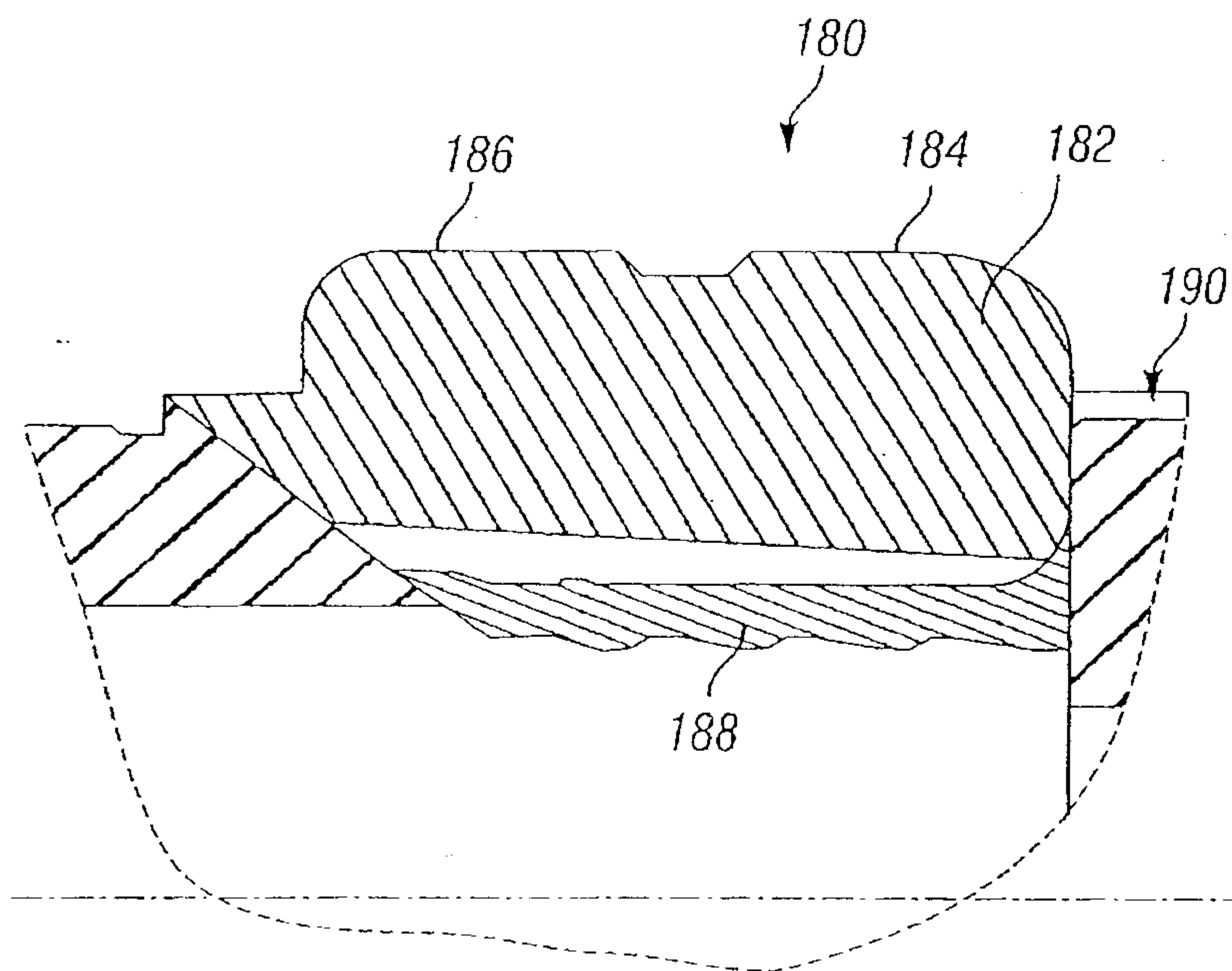


FIG. 18

REPLACEMENT SHEET

14/14

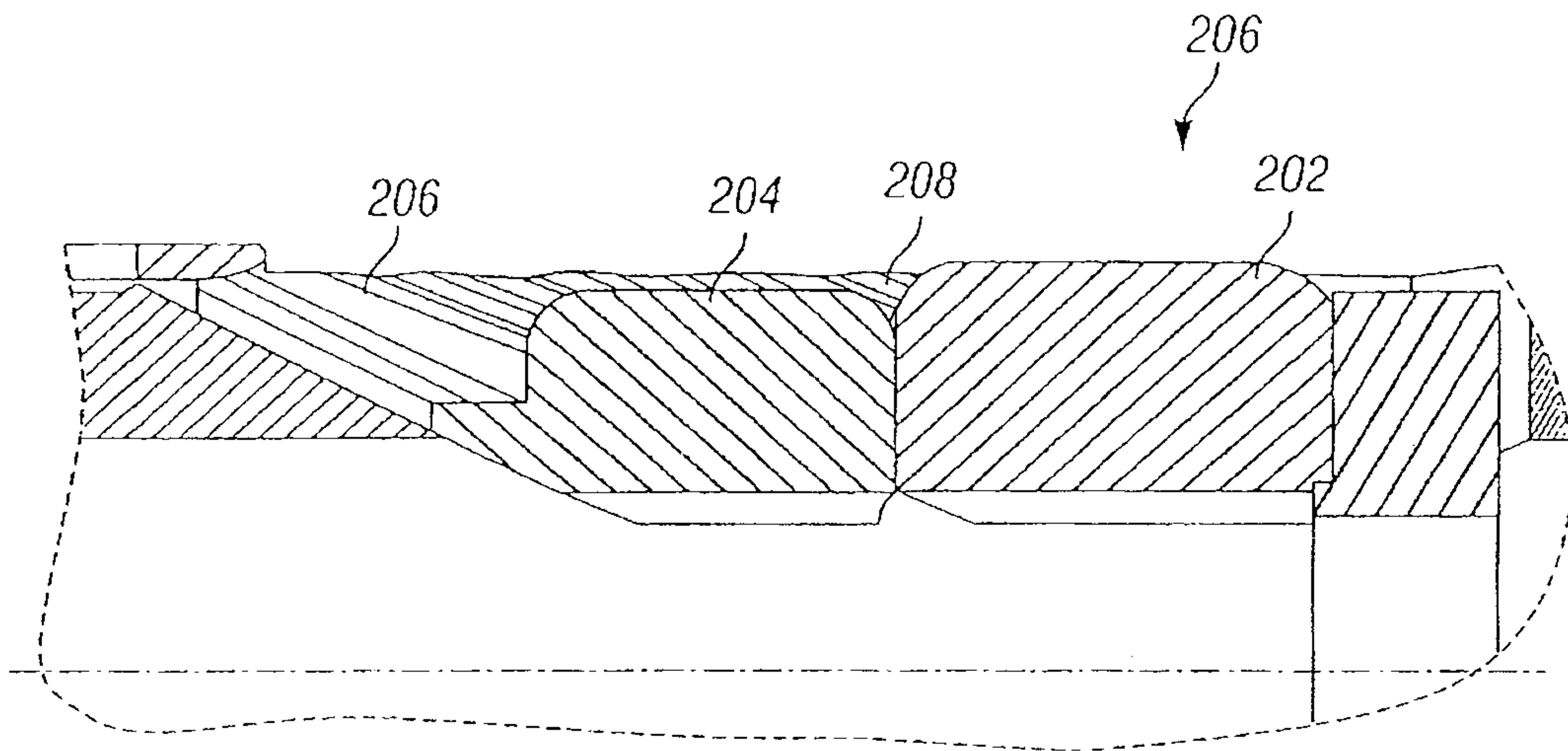


FIG. 19

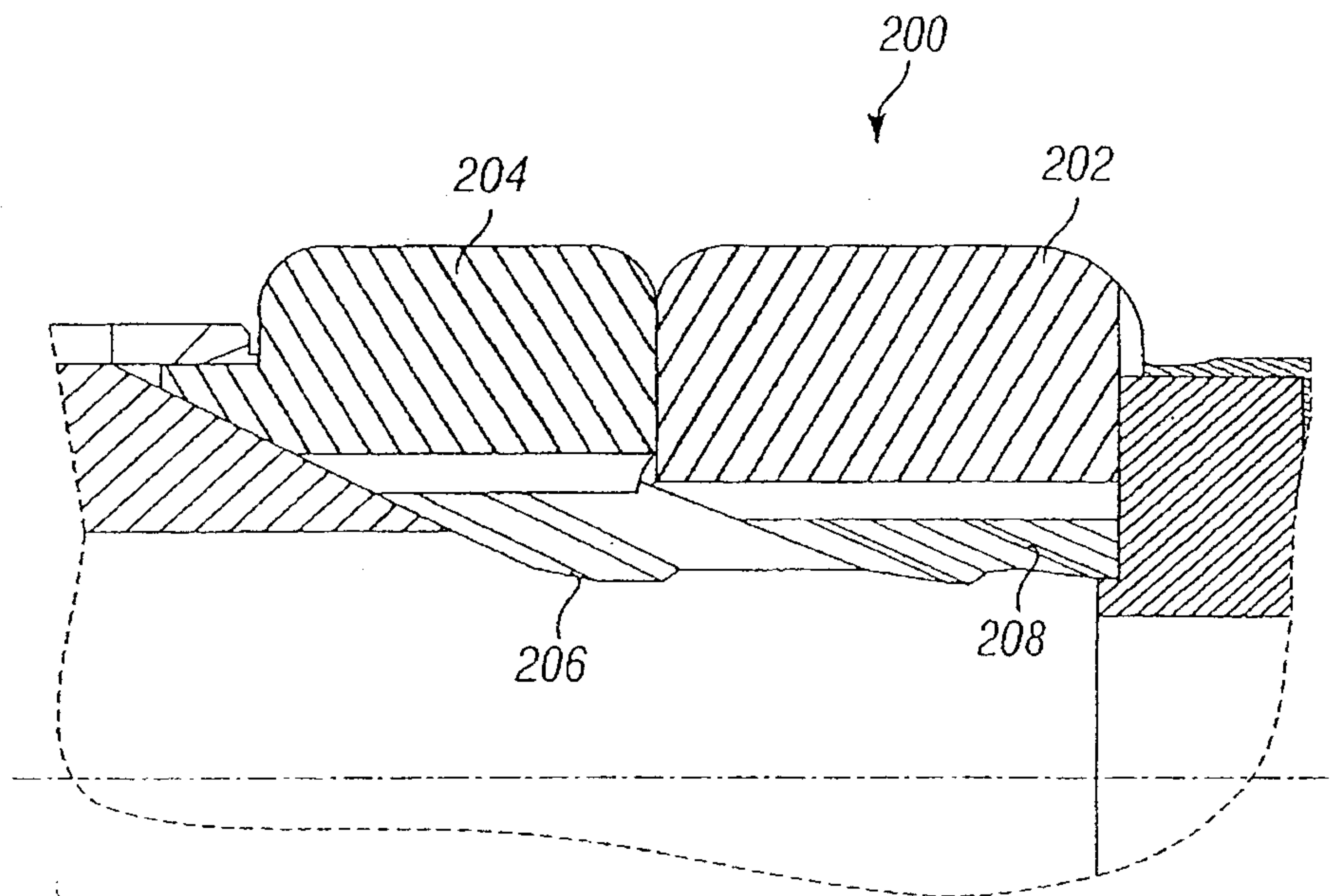


FIG. 20

