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(54) Title: APPARATUS AND METHOD FOR CONTROLLING FLUID FLOW IN A ROTARY DRILL BIT

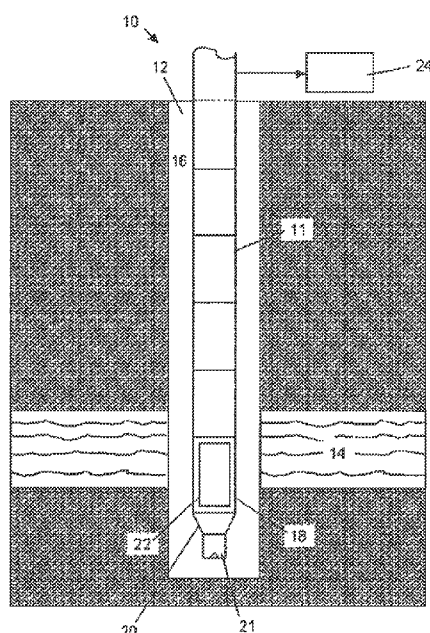


FIG. 1

(57) Abstract: An apparatus for drilling a borehole in an earth formation is disclosed. The apparatus includes: an earth-boring rotary drill bit including a bit body having a plurality of cutters engagable with a subterranean earth formation; a fluid conduit disposed in the bit body, the fluid conduit being in fluid communication with a source of drilling fluid and configured to receive a portion of the drilling fluid; a nozzle extending between the fluid conduit and a surface of the bit body, the nozzle configured to apply a stream of the portion of the drilling fluid to a first location of the surface; and a valve assembly including an actuator and a valve, the actuator configured to move the valve and divert a flow path of the portion of the drilling fluid, thereby diverting at least part of the stream to a second location on the surface.





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**APPARATUS AND METHOD FOR CONTROLLING FLUID FLOW
IN A ROTARY DRILL BIT**

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BACKGROUND

5 [0001] Rotary drill bits are commonly used for drilling boreholes or wells in earth formations. Examples of such rotary drill bits include roller cone bits that generally include three roller cones mounted on support legs extending from a bit body, and fixed cutter bits that generally include an array of cutting elements secured to a face region of the bit body. A hard, superabrasive material, such as mutually bonded particles of polycrystalline diamond,
10 may be provided on a surface of each cutting element to provide a cutting surface. Such cutting elements are often referred to as "polycrystalline diamond compact" (PDC) cutters.

 [0002] Rotary drill bits generally include one or more nozzles extending from a mud conduit through the drill bit to cool the cutters and remove cuttings from the drill bit. Mud or other fluid is pumped down a drillstring and into the drill bit where it flows out of the nozzles
15 and across the face of the cutters, cooling and cleaning them. The mud then flows up junk slots formed in the drill bit and into a borehole annulus, carrying the cuttings to the surface. The rate of fluid flow should be controlled in order to ensure that the correct components are cleaned and the fluid flow is sufficient to carry cuttings away from the drill bit. However, the number and configuration of the nozzles may be severely restricted due to the configuration
20 and size of the drill bit and due to the need to avoid interference between nozzles.

SUMMARY

 [0003] An apparatus for drilling a borehole in an earth formation includes: an earth-boring rotary drill bit including a bit body having a plurality of cutters engagable with a subterranean earth formation; a fluid conduit disposed in the bit body, the fluid conduit being
25 in fluid communication with a source of drilling fluid and configured to receive a portion of the drilling fluid; a nozzle extending between the fluid conduit and a surface of the bit body, the nozzle configured to apply a stream of the portion of the drilling fluid to a first location of the surface; and a valve assembly including an actuator and a valve, the actuator configured to move the valve and divert a flow path of the portion of the drilling fluid, thereby diverting
30 at least part of the stream to a second location on the surface.

[0004] A method of drilling a borehole in an earth formation includes: rotating a drill bit body including a plurality of cutters engagable with a subterranean earth formation; pumping a drilling fluid into a fluid conduit disposed in the drill bit body; receiving a portion of the drilling fluid in a nozzle extending between the fluid conduit and a surface of the drill bit body, and applying a stream of the portion of the drilling fluid from the nozzle to a first location of the surface; and actuating a valve assembly in operable communication with the nozzle and diverting at least part of the stream from a first location to a second location.

BRIEF DESCRIPTION OF THE DRAWINGS

[0005] The following descriptions should not be considered limiting in any way. With reference to the accompanying drawings, like elements are numbered alike:

FIG. 1 is a cross-sectional view of an exemplary embodiment of a well logging and/or drilling system;

FIG. 2 is a partial cross-sectional view of an exemplary embodiment of an earth-boring rotary drill bit of the system of **FIG. 1**;

FIG. 3 is a partial cross-sectional view of an exemplary embodiment of a nozzle of the drill bit of **FIG. 2** including a control valve assembly;

FIG. 4 is a partial cross-sectional view of an exemplary embodiment of an actuator of the control valve assembly of **FIG. 3**;

FIG. 5 is a perspective view of an exemplary embodiment of an actuator of the control valve assembly of **FIG. 3**;

FIG. 6 is a top view of exemplary embodiments of the control valve assembly of **FIG. 3**; and

FIG. 7 is a flow diagram illustrating a method of drilling a borehole in an earth formation.

DETAILED DESCRIPTION

[0006] Referring to **FIG. 1**, an exemplary embodiment of a well logging and/or drilling system **10** includes a drillstring **11** that is shown disposed in a borehole **12** that penetrates at least one earth formation **14** during a drilling, well logging and/or hydrocarbon production operation. The drillstring **11** includes a drill pipe, which may be one or more pipe sections or coiled tubing. A borehole fluid **16** such as a drilling fluid or drilling mud may be

pumped through the drillstring **11** and/or the borehole **12**. The well drilling system **10** also includes a bottomhole assembly (BHA) **18**.

[0007] As described herein, “borehole” or “wellbore” refers to a single hole that makes up all or part of a drilled well. As described herein, “formations” refer to the various features and materials that may be encountered in a subsurface environment. Accordingly, it should be considered that while the term “formation” generally refers to geologic formations of interest, that the term “formations,” as used herein, may, in some instances, include any geologic points or volumes of interest (such as a survey area).

[0008] In one embodiment, the BHA **18** includes a drill bit assembly **20** including a rotary drill bit **21** and associated motors adapted to drill through earth formations. Optionally, the BHA **18** includes one or more downhole tools **22** that include various sensors for measuring selected parameters of the drilling system, the borehole **12** and/or the formation **14**.

[0009] In one embodiment, a surface processing unit **24** is configured as a surface drilling control unit which controls various production and/or drilling parameters such as rotary speed, weight-on-bit, fluid flow parameters, pumping parameters and others and is configured to record and is optionally configured to display real-time data including formation evaluation data and drilling parameters such as vibration data. The BHA **18** and/or the downhole tool **22** is configured to communicate with the surface processing unit **24** via any suitable connection, such as a wired connection including a wireline or wired pipe, a fiber optic connection, a wireless connection and mud pulse telemetry. The surface processing unit **24** includes components as necessary to provide for storing and/or processing data collected from the downhole tool **22**. Exemplary components include, without limitation, at least one processor, storage, memory, input devices, output devices and the like.

[0010] Referring to **FIG. 2**, an exemplary embodiment of an earth-boring rotary drill bit **30** having a variable fluid nozzle is shown. Examples of suitable nozzles include threaded single-piece nozzles that are sealingly attached to a threaded inlet, fixed port nozzles, and multiple-piece nozzles including multiple nozzle conduits held in place by a nut or other fastener.

[0011] The drill bit **10** includes a bit body **32** secured to a shank **34**, such as a steel shank. The bit body **32** includes a crown **36** and a metal blank **38** that is partially embedded

in the crown 36. In one embodiment, the drill bit 10 is a polycrystalline diamond compact ("PDC") drill bit. Although the embodiments herein are described in conjunction with a PDC drill bit, such embodiments may be utilized with any suitable drill bit configuration, such as various types of fixed cutter and roller cone bits.

5 [0012] The bit body 32 is secured to the steel shank 34 by way of a threaded connection 40 and a weld 42 extending around the drill bit 30 on an exterior surface thereof along an interface between the bit body 32 and the steel shank 34. The steel shank 34 includes an API threaded connection portion 44 for attaching the drill bit 30 to the drillstring 11.

10 [0013] The bit body 32 includes a plurality of wings or blades 46, which are separated by external channels or conduits, also known as "junk slots" 48. One or more internal fluid passageways or nozzles 50 extend from a longitudinal bore 52, which extends through the steel shank 34 and partially through the bit body 32. A plurality of cutters 54 are provided on the bit body 32. In one embodiment, the cutters 54 are provided along each of the blades 46.

15 [0014] The nozzles 50 are disposed in the crown 36 in fluid communication with the bore 52 to allow a portion of the drilling fluid 16 to be diverted from the main fluid flow in the bore 52 and onto components of the crown 36. For example, each nozzle 50 is directed to a surface of the junk slot 48 and is directed to a selected blade 46 so that a cooling and/or cleaning flow of fluid is provided to the blade 46.

20 [0015] During drilling operations, the drill bit 30 is positioned at the bottom of the borehole 12 and rotated while the drilling fluid 16 is pumped to the bit body 32 through the longitudinal bore 52 and the nozzles 50. As the cutters 54 shear or scrape away the underlying earth formation, the formation cuttings mix with and are suspended within the drilling fluid 16 and are flushed from the junk slots 48 and into the annular space between the
25 wellbore 12 and the drillstring 11 to the surface.

 [0016] At least one of the nozzles 50 includes a control valve assembly 56 that is configured to control the volume and/or direction of drilling fluid 16 flowing through the nozzle 50. The control valve assembly 56 includes an actuator 58 operably connected to a valve 60, such as via a piston. The valve 60 incorporates any suitable configuration, such as
30 a ball valve that is rotatable to control the flow of fluid 16 through the nozzle 50 and or the

direction of flow. Another example of the valve 60 is a louver-type valve that is rotatable to adjust the amount and direction of fluid flow through the nozzle 50.

[0017] The actuator 58 is of any suitable configuration sufficient to rotate or advance the valve 60 in the nozzle 50. Examples of actuators include electromagnetic (via a motor or solenoid), piezoelectric, thermal, mechanical, pneumatic and hydraulic actuating mechanisms or any combination thereof.

[0018] In one embodiment, the actuator 58 is a cam-type actuator having an eccentric shape such that rotation of the cam-type actuator 58 causes movement of the valve 60. In another embodiment, the actuator 58 includes a piezoelectric element configured to move the valve 60 in response to application of a voltage to the piezoelectric element, which is controlled for example by a monitoring device.

[0019] Referring to FIG. 3, an embodiment of the valve assembly 56 is shown. The valve assembly 56 includes a piston 62 and the valve 60. In this embodiment, the valve 60 is a piston head having a surface 64 that is inclined relative to a central axis of at least a portion of the nozzle 50. As the valve assembly 56 is actuated, the piston head 60 moves from a peripheral location in the nozzle 50 toward a central location in the nozzle 50, thereby diverting the flow of fluid 16 toward one side of the nozzle 50. Movement of the piston head 60 causes the fluid 16 to divert in its path so that a different blade 46 or other location of the drill bit 30 is exposed to the fluid stream emitted from the nozzle 50. In addition to diverting the path, movement of the piston head may also change the pressure and/or shape of the fluid stream exiting the nozzle 50.

[0020] In one embodiment, the valve assembly 56 includes a spring 66 or other elastic biasing member to return the valve 60 to a rest position after actuation. Exemplary rest positions include a peripheral position in the nozzle interior, a position at an interior wall of the nozzle 50 and an exterior position relative to the nozzle 50. The spring 66 is fixedly connected relative to the drill bit body 32 at one end and fixedly connected to the piston 62 and/or the valve 60 at another end.

[0021] In one embodiment, the valve 60 is movable in response to a rotation rate of the drill bit 30. For example, the spring 66 counteracts a degree of centrifugal force caused by rotation of the drill bit 30, an excess of which causes the spring 66 to deform and allows the valve 60 to displace in a radial direction away from the rotational axis of the drill bit 30.

Increasing the rotational rate of the drill bit 30 causes the valve 60 to displace farther into the nozzle 50, which in turn causes the valve 60 to divert the fluid flow.

[0022] The surface 64 and the valve 60 is configured in any suitable manner to cause a desired diversion of the fluid flow as the valve 60 is moved into the nozzle 50. For example, the valve may take any suitable shape, such as a cylinder or a ball. The valve 60 may include any number of passages therethrough to create one or more individual streams that are emitted from the nozzle 50 in one or more selected directions. In one embodiment, the surface 64 is tapered so that the valve 60 has a smaller radial thickness at an upstream end of the surface 64 than the radial thickness in a downstream end of the surface 64.

[0023] Referring to FIG. 4, in one embodiment, the actuator 58 is a mechanism for causing radial displacement of the valve 60 in response to changes in the rotational rate of the drill bit 30. The actuator 58 includes a first tapered member 68 and a second tapered member 70 positioned in slidable contact and orthogonal to the first tapered member 68. An exemplary shape of the tapered members 68 and 70 is a conical shape.

[0024] The first tapered member is positioned so that a portion of the first tapered member is tapered relative to the drill bit rotational axis. In one embodiment, the first tapered member 68 is symmetrical about the rotational axis of the drill bit 30 or an axis that is parallel to the rotational axis of the drill bit 30. The second tapered member 70 is positioned so that the members 68 and 70 are in slidable contact between their respective tapered surfaces. As the drill bit 30 rotates, the second tapered member 70 slides along the first tapered member 68 in response to a reactive centrifugal force. The second tapered member 70 moves in a direction having both vertical (i.e. parallel to the rotational axis) and radial components. The piston is operably connected to the second tapered member 70 and is movable along the radial direction. The spring 66 or other biasing member may be included to maintain a radial position of the valve 60 relative to a selected rotation rate. As the rotation rate increases, the valve 60 moves away from the center of the drill bit 30 in the radial direction, causing diversion of the fluid flow. As the rotation rate decreases, the spring 66 causes the valve to move toward the center of the drill bit to reduce diversion of the fluid flow. In one embodiment, the spring 66 and the valve 60 are configured to return the valve 60 to a rest position as the rotation rate equals or falls below a selected rotation rate.

[0025] Referring to FIG. 5, in another embodiment, the actuator 58 is a cam-type actuator including at least one eccentrically shaped cam 74 operably connected to the piston 62. The cam 74 is rotatable about a rotating shaft or other member. The actuator 58 is operated by rotating the cam 74 to cause the piston 62 to move in a linear direction, such as a radial direction away from the rotational axis of the drill bit 30.

[0026] In one embodiment, the actuator 58 includes a cam assembly having a plurality of cams having at least two distinct cam profiles. For example, the cam assembly includes the first cam 74 and a second cam 76. The second cam 76 has a profile that is different than the first cam 74, so that rotation of the second cam 76 causes the piston 62 to move a different distance than rotation of the first cam 74. An adjustable pin 75 or other mechanism is included and is adjustable between a first and a second position in response to fluid pressure or actuation by a user or a processor. In one embodiment, a rocker arm is in contact with the piston 62 and has independently movable sections corresponding to each cam profile. In the first position, the pin 75 is disengaged so that only the first cam 74 is rotated, causing the valve 60 to move a first distance. In the second position, the pin 75 is engaged so that at least the second cam is rotated, causing the valve to move a second distance. An example of a cam assembly utilizing multiple cam profiles is included in the Variable Valve Timing and Lift Electronic Control (VTEC) automobile engine manufactured by Honda Motor Company.

[0027] Referring to FIG. 6, in one embodiment, the surface 64 includes at least one channel 72 or other feature therein for directing the path of the fluid 16. In one example, the channel 72 includes at least one two-way channel. In other examples, the channel 72 is a three-way, four-way or five-way channel. The configurations of the valve 60 and/or the surface 64 described herein are exemplary and non-limiting, as any number or shape of channels 72 or other features may be utilized.

[0028] Any of the channels may be shaped in such a manner as to control dispersion of the fluid stream that exits the nozzle 50. For example, the channels 72 can be tapered to control the spreading effect of the fluid stream.

[0029] In one embodiment, the control valve assembly 56 is connected in communication with a processor such as the surface processing unit 24 to allow for control of the valve assembly 56 by a user or directly by the processor. In another embodiment, the

control valve assembly **56** is self-contained within the drill bit **30** and automatically adjusts in response to the pressure of the drilling fluid **16** and/or the rotational rate of the drill bit **30**.

[0030] FIG. 7 illustrates a method **80** of drilling a borehole in an earth formation. The method **80** is used in conjunction with the drill bit **30** and the valve assembly **56**,
5 although the method **80** may be utilized in conjunction with any suitable combination of drill bits and valve assemblies. The method **80** includes one or more stages **81**, **82**, **83** and **84**. In one embodiment, the method **80** includes the execution of all of stages **81-84** in the order described. However, certain stages may be omitted, stages may be added, or the order of the stages changed.

10 [0031] In the first stage **81**, drilling is commenced by rotating the drill bit **30** and pumping drilling fluid through the conduit **52**.

[0032] In the second stage **82**, a portion of the drilling fluid **16** is diverted through the nozzle **50** and a fluid stream exits the nozzle **50** and is directed to a location of the drill bit **30**, such as one of the blades **46**. The location and shape of the stream is dependent on the
15 direction and configuration of the nozzle **50**.

[0033] In the third stage **83**, the valve **60** is actuated to adjust the stream. Adjustment of the stream may include adjusting the direction and/or shape of the stream to control the location on the drill bit surface that is affected by the stream.

[0034] In one embodiment, the valve **60** is actuated by an input signal provided by the
20 surface processing unit **24** or other processor. In another embodiment, actuation of the valve assembly **58** is adjusted in accordance with rotational speed of the drill bit **30**, such as the rotation (RPM) of the drill bit **30** in the case of a fixed cutter bit or the rotation of the individual cones in a roller cone bit. In another embodiment, the valve **60** is actuated automatically based on the rotational speed of the drill bit **30**.

25 [0035] In the fourth stage **84**, the fluid stream is directed away from the drill bit **30** via the junk slots **48** and into the annular region between the drillstring **11** and the borehole walls. The fluid stream, which includes cuttings from the drill bit, is further directed toward a surface location.

[0036] Generally, some of the teachings herein are reduced to instructions that are stored on machine-readable media. The instructions are implemented by a computer such as the surface processing unit 24 or other processor and provide operators with desired output.

5 [0037] The systems and methods described herein provide various advantages over prior art techniques, such as greater control over the direction and amount of fluid flow applied to the drill bit surface without the need to adjust or replace nozzles. Other advantages include a reduced number of nozzles required, allowing for improved design flexibility.

[0038] In support of the teachings herein, various analyses and/or analytical components may be used, including digital and/or analog systems. The system may have components such as a processor, storage media, memory, input, output, communications link (wired, wireless, pulsed mud, optical or other), user interfaces, software programs, signal processors (digital or analog) and other such components (such as resistors, capacitors, inductors and others) to provide for operation and analyses of the apparatus and methods disclosed herein in any of several manners well-appreciated in the art. It is considered that
15 these teachings may be, but need not be, implemented in conjunction with a set of computer executable instructions stored on a computer readable medium, including memory (ROMs, RAMs), optical (CD-ROMs), or magnetic (disks, hard drives), or any other type that when executed causes a computer to implement the method of the present invention. These instructions may provide for equipment operation, control, data collection and analysis and
20 other functions deemed relevant by a system designer, owner, user or other such personnel, in addition to the functions described in this disclosure.

[0039] Further, various other components may be included and called upon for providing aspects of the teachings herein. For example, a sample line, sample storage, sample chamber, sample exhaust, pump, piston, power supply (e.g., at least one of a
25 generator, a remote supply and a battery), vacuum supply, pressure supply, refrigeration (i.e., cooling) unit or supply, heating component, motive force (such as a translational force, propulsional force or a rotational force), magnet, electromagnet, sensor, electrode, transmitter, receiver, transceiver, controller, optical unit, electrical unit or electromechanical unit may be included in support of the various aspects discussed herein or in support of other
30 functions beyond this disclosure.

[0040] One skilled in the art will recognize that the various components or technologies may provide certain necessary or beneficial functionality or features. Accordingly, these functions and features as may be needed in support of the appended claims and variations thereof, are recognized as being inherently included as a part of the teachings herein and a part of the invention disclosed.

[0041] While the invention has been described with reference to exemplary embodiments, it will be understood by those skilled in the art that various changes may be made and equivalents may be substituted for elements thereof without departing from the scope of the invention. In addition, many modifications will be appreciated by those skilled in the art to adapt a particular instrument, situation or material to the teachings of the invention without departing from the essential scope thereof. Therefore, it is intended that the invention not be limited to the particular embodiment disclosed as the best mode contemplated for carrying out this invention, but that the invention will include all embodiments falling within the scope of the appended claims.

CLAIMS

1. An apparatus for drilling a borehole in an earth formation, the apparatus comprising:
an earth-boring rotary drill bit including a bit body having a plurality of cutters
engagable with a subterranean earth formation;
5 a fluid conduit disposed in the bit body, the fluid conduit being in fluid
communication with a source of drilling fluid and configured to receive a portion of the
drilling fluid;
a nozzle extending between the fluid conduit and a surface of the bit body, the nozzle
configured to apply a stream of the portion of the drilling fluid to a first location of the
10 surface; and
a valve assembly including an actuator and a valve, the actuator configured to move
the valve and divert a flow path of the portion of the drilling fluid, thereby diverting at least
part of the stream to a second location on the surface.
2. The drill bit of claim 1, further comprising a processor configured to control at least
15 one of rotation of the bit body and actuation of the valve assembly.
3. The drill bit of claim 1, wherein the rotary drill bit is a polycrystalline diamond
compact ("PDC") drill bit.
4. The drill bit of claim 1, wherein the bit body includes a plurality of blades, the first
location is on at least one of the plurality of blades, and the second location is on at least
20 another of the plurality of blades.
5. The drill bit of claim 1, wherein diverting the at least part of the stream includes
changing at least one of a direction, shape and pressure of the at least part of the stream.
6. The drill bit of claim 1, wherein the valve is selected from at least one of a ball valve
and a louver-type valve.
- 25 7. The drill bit of claim 1, wherein the actuator is selected from at least one of a
mechanical actuator, a piezoelectric actuator and a cam-type actuator.
8. The drill bit of claim 1, further comprising a piston in operable connection with the
actuator and the valve, wherein the valve is a piston head having a surface inclined relative to

a central axis of at least a portion of the nozzle and the piston head is movable between a peripheral location and a central location of the nozzle.

9. The drill bit of claim 8, wherein the valve includes at least one feature on the surface configured to direct a flow of the drilling fluid.

5 10. The drill bit of claim 1, further comprising a biasing member fixedly connected to the bit body and to the valve, the biasing member configured to bias the valve toward a rest position.

11. The drill bit of claim 1, wherein the valve is configured to move from a first position toward a second position in response to a change in a rotational rate of the bit body.

10 12. The drill bit of claim 11, wherein the actuator includes a first member and a second member, the first tapered member having a first tapered portion in slidable contact with a second tapered portion of the second member, and the first tapered portion is tapered relative to a rotational axis of the bit body.

13. The drill bit of claim 1, wherein the actuator includes a plurality of cams having at
15 least two distinct cam profiles.

14. A method of drilling a borehole in an earth formation, the method comprising:
rotating a drill bit body including a plurality of cutters engagable with a subterranean earth formation;

pumping a drilling fluid into a fluid conduit disposed in the drill bit body;

20 receiving a portion of the drilling fluid in a nozzle extending between the fluid conduit and a surface of the drill bit body, and applying a stream of the portion of the drilling fluid from the nozzle to a first location of the surface; and

actuating a valve assembly in operable communication with the nozzle and diverting at least part of the stream from a first location to a second location.

25 15. The method of claim 14, wherein actuating the valve assembly includes changing at least one of a fluid pressure and a rotational rate of the drill bit body.

16. The method of claim 14, further comprising directing the portion of the drilling fluid away from the drill bit into an annular region between a drillstring and a wall of the borehole.

17. The method of claim 14, wherein diverting the at least part of the stream includes changing at least one of a direction, shape and pressure of the at least part of the stream.

18. The method of claim 14, wherein the valve assembly includes an actuator selected from at least one of a mechanical actuator, a piezoelectric actuator and a cam-type actuator.

5 19. The method of claim 18, wherein the cam-type actuator includes at least one cam, and actuating the valve assembly includes rotating the cam between a first position and a second position.

20. The method of claim 14, wherein the valve assembly includes a valve having a surface inclined relative to a central axis of at least a portion of the nozzle, and actuating the
10 valve assembly includes moving the valve from a peripheral location toward a central location of the nozzle.

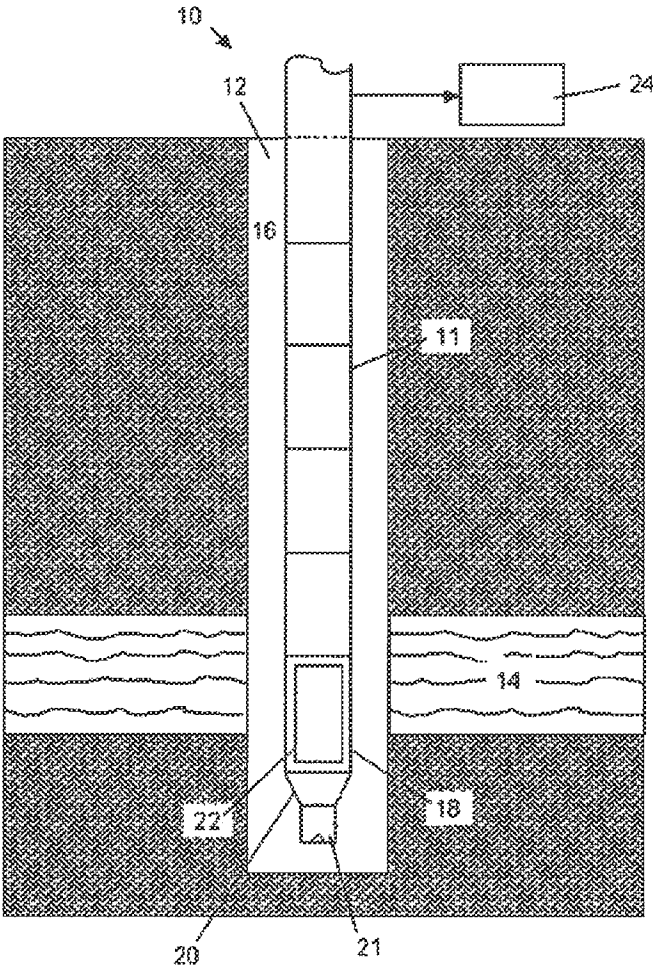


FIG. 1

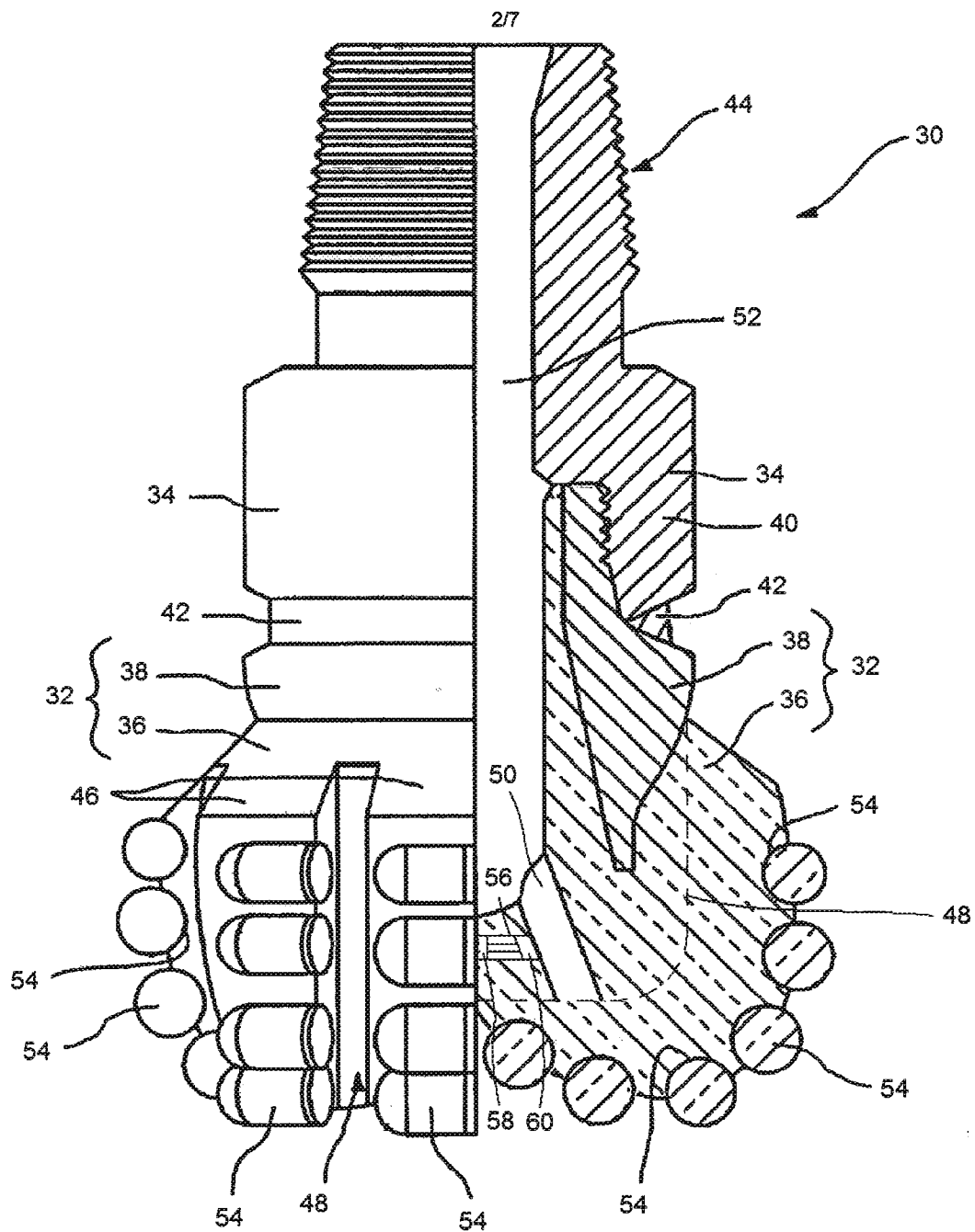


FIG. 2

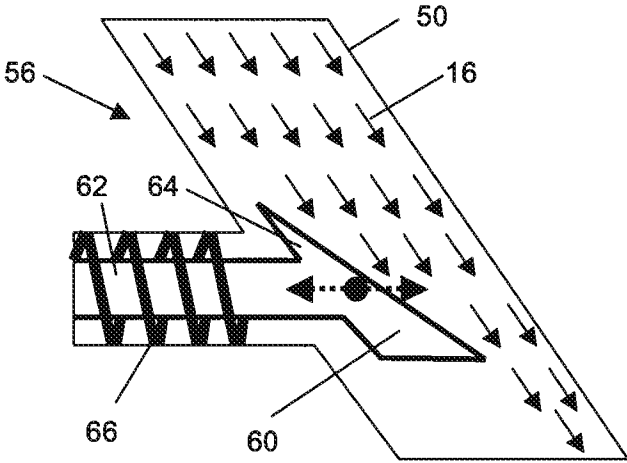


FIG. 3

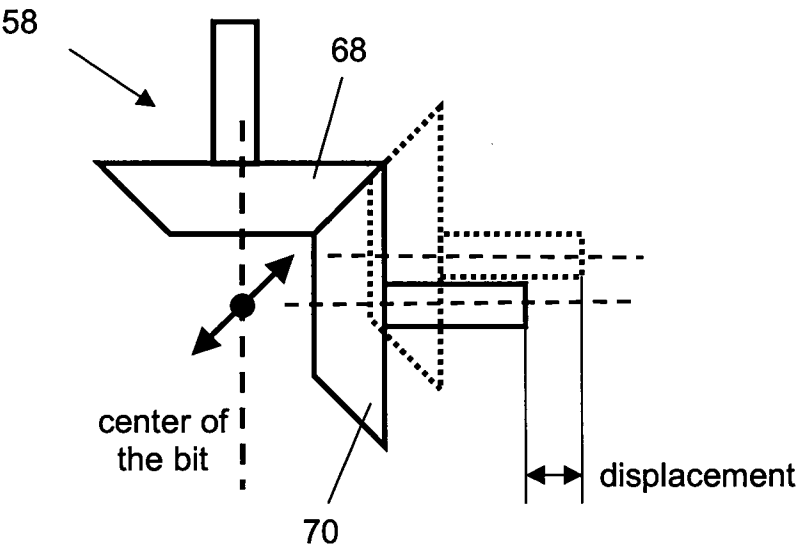


FIG. 4

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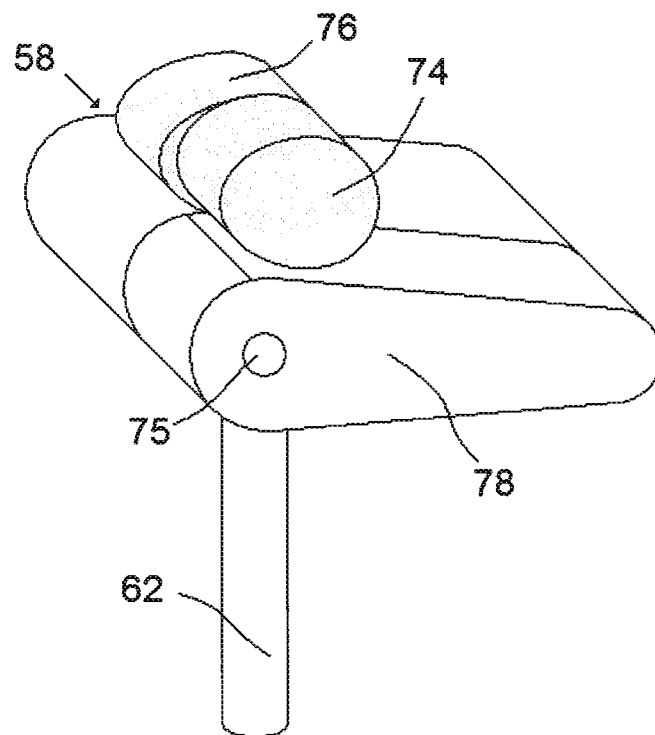


FIG. 5

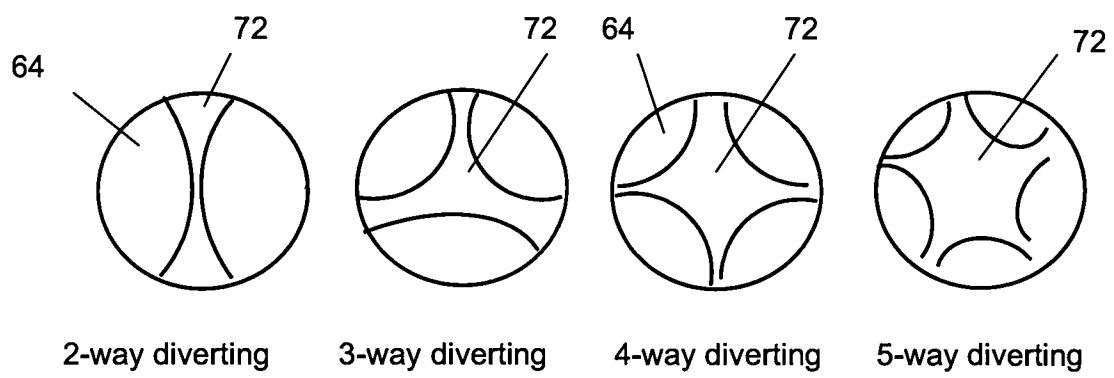


FIG. 6

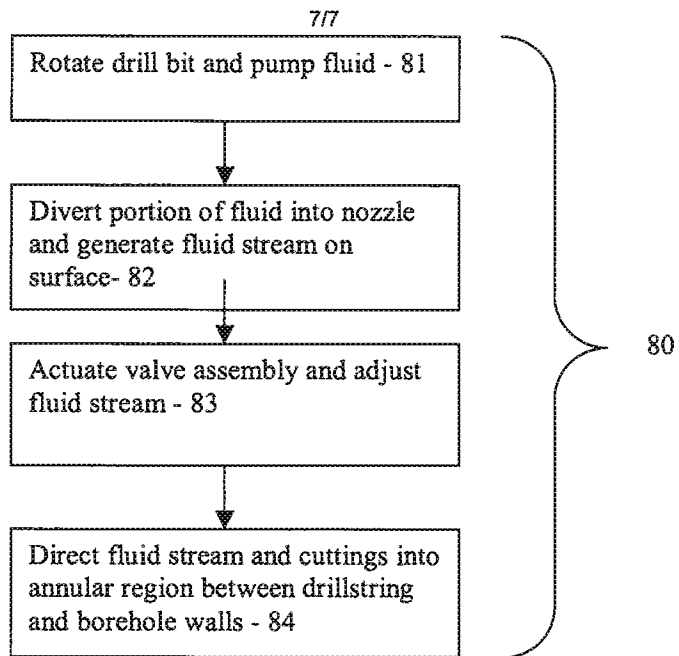


FIG. 7