Title: DRILLING FLUID CIRCULATION SYSTEM AND METHOD

Abstract: The present invention provides drilling systems for drilling wellbores. The drilling system includes an umbilical that passes through a wellhead and carries a drill bit. A drilling fluid system supplies drilling fluid into an annulus (supply line) between the umbilical and the wellbore, which discharges at the drill bit bottom and returns to the wellhead through the umbilical (return line) carrying the drill cuttings. A fluid circulation device, such as a turbine or centrifugal pump, is operated in the return line to provide the primary motive force for circulating drilling fluid through a fluid circuit formed by the supply line and return line. Optionally, a secondary fluid circulation device can be used to provide localized flow control or suction pressure to improve bit cleaning.
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NOVEL WELLBORE FLUID CIRCULATION SYSTEM AND METHOD

BACKGROUND OF THE INVENTION

Field of the Invention

This invention relates generally to oilfield wellbore drilling systems and more particularly to drilling fluid circulation systems that utilize a wellbore fluid circulation device to optimize drilling fluid circulation.

Background of the Art

Oilfield wellbores are drilled by rotating a drill bit conveyed into the wellbore by a drill string. The drill string includes a drill pipe (tubing) that has at its bottom end a drilling assembly (also referred to as the "bottomhole assembly" or "BHA") that carries the drill bit for drilling the wellbore. The drill pipe is made of jointed pipes. Alternatively, coiled tubing may be utilized to carry the drilling of assembly. The drilling assembly usually includes a drilling motor or a "mud motor" that rotates the drill bit. The drilling assembly also includes a variety of sensors for taking measurements of a variety of drilling, formation and BHA parameters. A suitable drilling fluid (commonly referred to as the "mud") is supplied or pumped under pressure from a source at the surface down the tubing. The drilling fluid drives the mud motor and then discharges at the bottom of the drill bit. The drilling fluid returns uphole via the annulus between the drill string and the wellbore inside and carries with it pieces of formation (commonly referred to as the "cuttings") cut or produced by the drill bit in drilling the wellbore.

For drilling wellbores under water (referred to in the industry as "offshore" or "subsea" drilling) tubing is provided at a work station (located on a vessel or platform). One or more tubing injectors or rigs are used to move the tubing into and out of the wellbore. In riser-type drilling, a riser, which is formed by joining sections of casing or pipe, is deployed between the drilling vessel and the wellhead equipment at the sea bottom and is utilized to guide the tubing to the wellhead. The riser also serves as a conduit for fluid returning from the wellhead to the sea surface.
During drilling with conventional drilling fluid circulation systems, the drilling operator attempts to carefully control the fluid density at the surface so as to control pressure in the wellbore, including the bottomhole pressure. Referring to Figure 1A, there is shown a surface pump P1 at the surface S1 for pumping a supply fluid SF1 via a drill string DS1 into a wellbore W1. The return fluid RF1 flows up an annulus A1 formed by the drill string DS1 and wall of the wellbore W1. The drilling fluid in the annulus A1 carries with it the cuttings C1 generated by the cutting action of a drill bit (not shown). The drill string DS1 is shown separately from the wellbore W1 to better illustrate the flow path of the circulating drilling fluid. Typically, the operator maintains the hydrostatic pressure of the drilling fluid in the wellbore above the formation or pore pressure to avoid well blow-out. Under this regime, the surface pump P1 has the burden of flowing the drilling fluid down the drill string DS1 and also upwards along the annulus A1. Accordingly, the surface pump P1 must overcome the frictional losses along both of these paths. Moreover, the surface pump P1 must maintain a flow rate in the annulus A1 that provides sufficient fluid velocity to carry entrained cuttings C1 to the surface. Thus, in this conventional arrangement, the pumping capacity of the surface pump P1 is typically selected to (i) overcome frictional losses present as the drilling fluid flows through the drill string DS1 and the annulus A1; and (ii) provide a flow velocity or flow rate that can carry or lift the cuttings C1 through the annulus A1. It will be appreciated that such pumps must have relatively large pressure and flow rate capacities. Furthermore, these relatively large pressures can damage the exposed formation F1 (or “open hole”) below the casing CA1. For instance, the fluid pressure needed to provide the desired fluid flow rate can fracture the rock or earth forming the wall of the wellbore W1 and thereby compromise the integrity of the wellbore W1 at the exposed and unprotected formation F1.

In another conventional drilling arrangement shown in Figure 1B, there is shown a pump P2 at the surface for pumping a supply fluid SF2 via an annulus A2 into a wellbore W2. The return fluid RF2 flows up the drill string DS2 carrying with it the entrained cuttings C2. In this regime, the surface pump P2 also has the burden of flowing the drilling fluid down the drill string DS2 and also upwards along the annulus A2. Accordingly, the surface
pump P2 must overcome the frictional losses along both of these paths. Further, because the cross-sectional area of the drill string DS2 is smaller than the cross sectional area of the annulus A2, the density of the return fluid RF2 and cuttings C2 flowing in the drill string DS2 is higher than the density of the return fluid RF1 and cuttings in the annulus A1 of Figure 1A under similar drilling conditions (e.g., the same rate of penetration (ROP)). This higher fluid density requires a correspondingly higher pressure differential and flow rate in order to lift the cuttings C2 to the surface S2. Thus, in this conventional arrangement, the pumping capacity of the surface pump P2 is typically selected to (i) overcome frictional losses present as the drilling fluid flows through the annulus A and the drill string DS2; and (ii) provide a flow velocity or flow rate that can carry or lift the cuttings C2 through the annulus A2. It will be appreciated that such pumps must also have relatively large pressure and flow rate capacities.

The present invention addresses these and other drawbacks of conventional fluid circulation systems for supporting well construction activity.

**SUMMARY OF THE INVENTION**

The present invention provides wellbore systems for performing downhole wellbore operations for both land and offshore wellbores. Such drilling systems include a rig that moves an umbilical (e.g., drill string) into and out of the wellbore. A bottomhole assembly, carrying the drill bit, is attached to the bottom end of the drill string. A well control assembly or equipment on the wellhead receives the bottomhole assembly and the umbilical. A drilling fluid system supplies a drilling fluid via a fluid circulation system having a supply line and a return line. During operation, drilling fluid is fed into the supply line, which can include an annulus formed between the umbilical and the wellbore wall. This fluid washes and lubricates the drill bit and returns to the well control equipment carrying the drill cuttings via the return line, which can include the umbilical.

In one embodiment of the present invention, a fluid circulation device, such as a positive displacement or centrifugal pump, positioned along the return line provides the primary motive force for circulating the drilling fluid through the supply line and return line of the fluid circulation system. By "primary motive force," it is meant that operation of the fluid circulation device
provides the majority of the force or differential pressure required to circulate drilling fluid through the supply line and return line. In a separate arrangement, one or more supplemental fluid circulation devices are coupled to the supply line and/or return line to assist in circulating drilling fluid. By "supplemental," it is meant that these additional fluid circulation devices are task-specific (e.g., providing zones of higher or lower fluid pressure/flow rates, improve bit cleaning, and/or overcoming circulation losses in specific segments of the fluid circulation system), but primarily operate in cooperation with the fluid circulation device. The fluid circulation device can be any device adapted to actively induce flow or controlled movement of a fluid body or column. Such devices can include centrifugal pumps, positive displacement pumps, piston-type pumps, jet pumps, magnetohydrodynamic drives, and other like devices. In one embodiment of the present invention, the operation of the fluid circulation device is generally independent of the operation of the drill bit. For instance, the flow rate or pressure differential provided by the fluid circulation device can be controlled without necessarily adjusting the rotational speed of the drill bit or the driver (e.g., rotating drill string) rotating the drill bit. A controller in the system may be utilized to control the operation of the fluid circulation device according to programmed instructions and/or in response to a parameter of interest, which may be pressure, fluid flow, a characteristic of the wellbore fluid or the formation of any other suitable downhole or surface measured parameter.

The system also includes downhole devices for performing a variety of functions. Exemplary downhole devices include devices that control the drilling fluid flow rate and flow paths. For example, the system can include one or more flow-control devices that can stop the flow of the fluid in the umbilical and/or the annulus. Such flow-control devices can be configured to direct fluid from the annulus into the umbilical. Another exemplary downhole device can be configured for processing the cuttings (e.g., reduction of cutting size) and other debris flowing in the return line. For example, a comminution device can be disposed in the return line upstream of the fluid circulation device.

In one embodiment, sensors communicate with a controller via a telemetry system control the drilling activity according to one or more
parameters (e.g., a specified range of the wellbore pressure at a zone of interest or specified rate of penetration). The sensors are strategically positioned throughout the system to provide information or data relating to one or more selected parameters of interest such as drilling parameters, drilling assembly or BHA parameters, and formation or formation evaluation parameters. The controller suitable for drilling operations can include programs for maintaining drilling activity within the specified parameter or parameters. The controller may be programmed to activate downhole devices according to programmed instructions or upon the occurrence of a particular condition.

In one embodiment, a wellbore assembly utilizing a bit rotated by a downhole motor and a fluid circulation device driven by an associated motor. A power transmission line or conduit supplies power to the each of the motors. Additionally, the wellbore assembly can includes a controller coupled to sensors configured to measure one or more parameters of interest (e.g., pressure of the supply fluid). In one arrangement, the motors are variable speed electric motors that are adapted for use in a wellbore environment. Other embodiments of motors can be operated by pressurized gas, hydraulic fluid, and other energy streams supplied from a surface location. Other equally suitable arrangements can include a single motor (electric or otherwise) that drives both the bit and the fluid circulation device. In another embodiment, the wellbore system includes a downhole power unit for energizing one or more of the motors. The stored energy supply, in certain embodiments, is replenished from a surface source. Further, a plurality of fluid circulation devices can be positioned serially or in parallel along the return line.

Examples of the more important features of the invention have been summarized (albeit rather broadly) in order that the detailed description thereof that follows may be better understood and in order that the contributions they represent to the art may be appreciated. There are, of course, additional features of the invention that will be described hereinafter and which will form the subject of the claims appended hereto.
BRIEF DESCRIPTION OF THE DRAWINGS

For detailed understanding of the present invention, reference should be made to the following detailed description of the preferred embodiment, taken in conjunction with the accompanying drawing:

Figure 1A is a schematic illustration of one conventional arrangement for circulating fluid in a wellbore;

Figure 1B is a schematic illustration of another conventional arrangement for circulating fluid in a wellbore;

Figure 2 is a schematic illustration of an exemplary arrangement for circulating fluid in a wellbore according to one embodiment of the present invention;

Figure 3 is a schematic elevation view of well construction system using a fluid circulation device made in accordance with one embodiments of the present invention;

Figure 4 is a schematic illustration of one embodiment of an arrangement according to the present invention wherein a wellbore system uses a fluid circulation device energized by a surface source; and

Figure 5 is a schematic illustration of one embodiment of an arrangement according to the present invention wherein a wellbore system uses a fluid circulation device energized by a local (wellbore) source.

DETAILED DESCRIPTION OF PREFERRED EMBODIMENTS

Referring initially to Figure 2, there is schematically illustrated a well construction facility 10 for forming a wellbore 12 in an earthen formation 14. The facility 10 includes a rig 16 and known equipment such as a wellhead, blow-out preventers and other components associated with the drilling, completion and/or workover of a hydrocarbon producing well. For clarity, these components are not shown. Moreover, the rig 16 may be situated on land or at an offshore location. In accordance with one embodiment of the present invention, the facility 10 includes a fluid circulation system 18 for providing drilling fluid to a downhole tool or drilling assembly 19. One exemplary fluid circulation system 18 includes a surface mud supply 20 that provides drilling fluid into a supply line 22. This drilling fluid circulates through the wellbore 12 and returns via a return line 24 to the surface. For clarity, the downward flow of drilling fluid is identified by arrow 26 and the upward flow of
drilling fluid is identified by arrow 28. The term "line" as used in supply line 22 and return line 24 should be construed in its broadest possible sense. A line can be formed of one continuous conduit, path or channel or a series of connected conduits, paths or channels suitable for conveying a fluid. The line can be co-axial or concentric with another line and include cross-flow subs. Moreover, the line can include man-made sections (tubulars) and/or earthen sections (e.g., an annulus). Conventionally, a casing 33 for providing structural integrity is installed in at least a portion the wellbore 12, the portion below the casing 33 being generally referred to as "open hole" or exposed formation 31. During drilling, the drilling fluid flowing uphill, shown by arrow 28, will have entrained rock and earth formed by a drill bit (also referred to as "return fluid"). In one exemplary arrangement, the supply line 22 can include an annulus 35 of the wellbore 12 and the return line 24 can include drill string, a coiled tubing, a casing, a liner, an umbilical, and/or other tubular member connecting a downhole tool, bottomhole assembly, or drilling assembly 19 to the rig 16.

In one embodiment, a fluid circulation device 30 is positioned in the return line 24 above or uphill of a well bottom 32. The fluid circulation device 30 provides the primary motive force for causing drilling fluid to flow or circulate down through the supply line 22 and up through the return line 24. By "primary motive force," it is meant that operation of the fluid circulation device provides the majority of the force or pressure differential required to circulate drilling fluid through the supply line 22, the BHA 19 and return line 24. In one arrangement, the operation of the fluid circulation device 30 is substantially independent of the operation of the drill bit (not shown) of the BHA 19. For example, the flow rate or pressure differential provided by the fluid circulation device 30 can be controlled without having to alter drill bit rotation (RPM). Thus, the operational parameters of the fluid circulation device can be controlled without necessarily reducing or increasing the rotational speed, torque, or other operational parameter of the bit or the drill string rotating the drill bit. Such an arrangement can, for instance, enable circulation of drilling fluid even when the drill bit either does not rotate or rotates a minimal amount. It should be understood that the fluid circulation device can be any device, arrangement, or mechanism adapted to actively
induce flow or controlled movement of a fluid body or column. Such devices can include mechanical, electro-mechanical, hydraulic-type systems such as centrifugal pumps, positive displacement pumps, piston-type pumps, jet pumps, magneto-hydrodynamic drives, and other like devices.

Operation of the fluid circulation device 30 creates, in certain arrangements, a pressure differential that causes the otherwise mostly static fluid column in the supply line 22 (along with drill cuttings) to be drawn across the BHA 19 and into the return line 24 at the vicinity of the well bottom 32. To the extent needed to maintain a specified flow rate, the fluid circulation device 30 can increase the flow rate of the fluid in the supply line 22 by increasing the pressure differential in the vicinity of the well bottom 32. The fluid circulation device 30 also provides sufficient "lifting" force to flow the return fluid and entrained cuttings to the surface through the return line 24. It should therefore be appreciated that the fluid circulation device 30 can actively induce fluid circulation in both the supply line 22 and the return line 24.

In one exemplary deployment, the mud supply 20 fills the supply line 22 with drilling fluid by allowing gravity to flow the drilling fluid toward the well bottom 32. Other suitable devices could include small surface pumps for providing pressure necessary to convey the drilling fluid to the inlet of supply line 22. In another exemplary arrangement, supplemental fluid circulation devices (not shown) can be coupled to the supply line 22 and/or return line 24 to assist in circulating drilling fluid. By "supplemental," it is meant that these additional fluid circulation devices circulate drilling fluid to provide a motive force to overcome specific factors but primarily operate in cooperation with the fluid circulation device 30. For example, a supplemental fluid circulation device can be coupled to the supply line 22 to vary the pressure or flow rate in the fluid column in the supply line 22 a predetermined amount; e.g., an amount sufficient to offset circulation losses in the supply line 22. Thus, in contrast to conventional fluid circulation systems, the burden of circulating drilling fluid into and out of the wellbore is taken up by a fluid circulation device disposed in the wellbore along the return line rather than by fluid circulation devices at the surface ends of the supply line 22 and the return line 24.
In certain embodiments, the system 10 can also include a controller 34 for controlling the fluid circulation device 30. An exemplary controller 34 controls the fluid circulation device 30 in response to signals transmitted by one or more sensors (not shown) that are indicative of one or more of: pressure, fluid flow, a formation characteristic, a wellbore characteristic and a fluid characteristic, a surface measured parameter or a parameter measured in the drill string. The controller 34 can include circuitry and programs that can, based on received information, determine the operating parameters that provide optimal drilling conditions (rate of penetration, well bore stability, optimized drilling flow rate, etc.)

Referring now to Figures 1A, 1B and 2, it will apparent to one skilled in the art that the Figure 2 embodiment of the present invention has a number of advantages over conventional drilling fluid circulation systems. First, in contrast to conventional arrangements wherein a surface pump must “push” fluid through both the supply line, the BHA and return line, the fluid circulation device 30, the device for providing the primary motive force for fluid circulation, is strategically positioned in the return line. Thus, the fluid circulation device 30 need only be configured to “push” fluid through the return line. A passive mechanism, such as gravity-assisted flow, can be use to flow drilling fluid along the annulus 35. Thus, because the fluid circulation device 30 actively flows drilling fluid through roughly half of the fluid circuit, the power requirements of the fluid circulation device 30 are reduced to some degree. Additionally, the fluid circulation device 30 primarily acts upon the fluid flowing through the return line 24 (e.g., an umbilical such as a drill string) not on the fluid flowing in the annulus and, in particular, the fluid flowing in the portion exposed to the formation 31. Thus, operation of the fluid circulation device 30 does not increase the fluid pressure in the drilling fluid residing in the open hole section 31 of the wellbore 12. Advantageously, therefore, circulation of drilling fluid is provided in the fluid circuit servicing the wellbore 32 without creating fluid pressures in the annulus 35 that could damage the earth and rock making up the formation. Stated differently, the fluid circulation device 30 is advantageously positioned to allow the primary motive force or differential needed to circulate drilling fluid to act upon fluid confined within the
return line 24 so as to maintain a relatively benign pressure in the fluid column in the annulus 34.

The numerous embodiments and adaptations of the present invention will be discussed in further detail below.

Referring now to Figure 3, there is schematically illustrated a system 100 for performing one or more operations related to the construction, logging, completion or work-over of a hydrocarbon producing well. In particular, Figure 3 shows a schematic elevation view of one embodiment of a wellbore drilling system 100 for drilling wellbore 32. The drilling system 100 includes a drilling platform 102. The platform 102 can be situated on land or can be a drill ship or another suitable surface workstation such as a floating platform or a semi-submersible for offshore wells. For offshore operations, additional known equipment such as a riser and subsea wellhead will typically be used. To drill a wellbore 32, well control equipment 104 (also referred to as the wellhead equipment) is placed above the wellbore 32. The wellhead equipment 104 includes a blow-out-preventer stack 106 and a lubricator (not shown) with its associated flow control.

This system 100 further includes a well tool such as a drilling assembly or a bottomhole assembly ("BHA") 108 at the bottom of a suitable umbilical such as umbilical 110. In one embodiment, the BHA 108 includes a drill bit 112 adapted to disintegrate rock and earth. The umbilical 110 can be formed partially or fully of drill pipe, metal or composite coiled tubing, liner, casing or other known members. Additionally, the umbilical 110 can include data and power transmission carriers such fluid conduits, fiber optics, and metal conductors. To drill the wellbore 32, the BHA 108 is conveyed from the drilling platform 102 to the wellhead equipment 104 and then inserted into the wellbore 32. The umbilical 110 is moved into and out of the wellbore 32 by a suitable tubing injection system.

In accordance with one aspect of the present invention, the drilling system 100 includes a fluid circulation system 120 that includes a surface mud system 122, a supply line 124, and a return line 126. The supply line 124 includes an annulus 35 formed between the umbilical 110 and the casing 128 or wellbore wall 130. During drilling, the surface mud system 122 supplies a drilling fluid to the supply line 124, the downward flow of the drilling
fluid being represented by arrow 132. The mud system 122 includes a mud pit or supply source 134. In exemplary offshore configurations, the source 134 can be at the platform, on a separate rig or vessel, at the seabed floor, or other suitable location. In one embodiment, the source 134 is a variable volume tank positioned at a seabed floor. While gravity may be used as the primary mechanism to induce flow through the umbilical 110, one or more pumps 136 may be utilized to assist the flow of the drilling fluid 35. The drill bit 112 disintegrates the formation (rock) into cuttings (not shown). The drilling fluid leaving the drill bit travels uphole through the return line 126 carrying the drill cuttings therewith (a “return fluid”). The return line 126 can convey the return fluid to a suitable storage tank at a seabed floor, to a platform, to a separate vessel, or other suitable location. In one embodiment, the return fluid discharges into a separator (not shown) that separates the cuttings and other solids from the return fluid and discharges the clean fluid back into the mud pit 134 at the surface or an offshore platform.

Once the well 32 has been drilled to a certain depth, casing 128 with a casing shoe 138 at the bottom is installed. The drilling is then continued to drill the well to a desired depth that will include one or more production sections, such as section 140. The section below the casing shoe 138 may not be cased until it is desired to complete the well, which leaves the bottom section of the well as an open hole, as shown by numeral 142.

As noted above, the present invention provides a drilling system for controlling bottomhole pressure at a zone of interest designated by the numeral 140 and also optimize drilling parameters such as drilling fluid flow rate and rate of penetration. In one embodiment of the present invention, a fluid circulation device 150 is fluidically coupled to return line 126 downstream of the zone of interest 140. The fluid circulation device is device that is capable of inducing flow of fluid in the supply line 124 and the return line 126, such as by creating a pressure differential “ΔP” across the device. Thus, the fluid circulation device 126 produces a sufficient suction pressure at the drill bit 112 to draw in the drilling fluid within the supply line 124 (annulus 91) and “lift” or flow the drilling fluid and entrained cuttings to the surface via the return line 126. Additionally, by producing a controlled pressure drop, the fluid circulation device 150 reduces upstream pressure, particularly in zone 140.
The fluid circulation device 150 in certain arrangements can be a suitable pump, e.g., a multi-stage centrifugal-type pump. Moreover, positive displacement type pumps such as a screw or gear type or moineau-type pumps may also be adequate for many applications. For example, the pump configuration may be single stage or multi-stage and utilize radial flow, axial flow, or mixed flow.

The system 100 also includes downhole devices that separately or cooperatively perform one or more functions such as controlling the flow rate of the drilling fluid and controlling the flow paths of the drilling fluid. For example, the system 100 can include one or more flow-control devices that can stop the flow of the fluid in the umbilical 110 and/or the annulus 35. Figure 1A shows an exemplary flow-control device 152 that includes a device 154 that can block the fluid flow within the umbilical 110 and a device 156 that blocks can block fluid flow through the annulus 35. The device 152 can be activated when a particular condition occurs to insulate the well above and below the flow-control device 152. For example, the flow-control device 152 may be activated to block fluid flow communication when drilling fluid circulation is stopped so as to isolate the sections above and below the device 152, thereby maintaining the wellbore below the device 152 at or substantially at the pressure condition prior to the stopping of the fluid circulation.

The flow-control devices 154, 156 can also be configured to selectively control the flow path of the drilling fluid. For example, the flow-control device 154 in the umbilical 110 can be configured to direct some or all of the fluid in the annulus 35 into umbilical 110. Such an operation may be used, for example, to reduce the density of the cuttings-laden fluid flowing in the umbilical 110. The flow-control device 156 may include check-valves, packers and any other suitable device. Such devices may automatically activate upon the occurrence of a particular event or condition.

The system 100 also includes downhole devices for processing the cuttings (e.g., reduction of cutting size) and other debris flowing in the umbilical 110. For example, a comminution device 160 can be disposed in the umbilical 110 upstream of the fluid circulation device 150 to reduce the size of entrained cutting and other debris. The comminution device 160 can use known members such as blades, teeth, or rollers to crush, pulverize or
otherwise disintegrate cuttings and debris entrained in the fluid flowing in the umbilical 110. The comminution device 160 can be operated by an electric motor, a hydraulic motor, by rotation of drill string or other suitable means. The comminution device 160 can also be integrated into the fluid circulation device 150. For instance, if a multi-stage turbine is used as the fluid circulation device 150, then the stages adjacent the inlet to the turbine can be replaced with blades adapted to cut or shear particles before they pass through the blades of the remaining turbine stages.

Sensors $S_{1-n}$ are strategically positioned throughout the system 100 to provide information or data relating to one or more selected parameters of interest (pressure, flow rate, temperature). In one embodiment, the devices 20 and sensors $S_{1-n}$ communicate with a controller 170 via a telemetry system (not shown). Using data provided by the sensors $S_{1-n}$, the controller 170 can, for example, maintain the wellbore pressure at zone 140 at a selected pressure or range of pressures and/or optimize the flow rate of drilling fluid. The controller 170 maintains the selected pressure or flow rate by controlling the fluid circulation device 150 (e.g., adjusting amount of energy added to the return line 126) and/or other downhole devices (e.g., adjusting flow rate through a restriction such as a valve).

When configured for drilling operations, the sensors $S_{1-n}$ provide measurements relating to a variety of drilling parameters, such as fluid pressure, fluid flow rate, rotational speed of pumps and like devices, temperature, weight-on bit, rate of penetration, etc., drilling assembly or BHA parameters, such as vibration, stick slip, RPM, inclination, direction, BHA location, etc. and formation or formation evaluation parameters commonly referred to as measurement-while-drilling parameters such as resistivity, acoustic, nuclear, NMR, etc. One exemplary type of sensor is a pressure sensor for measuring pressure at one or more locations. Referring still to Fig. 1A, pressure sensor $P_1$ provides pressure data in the BHA, sensor $P_2$ provides pressure data in the annulus, pressure sensor $P_3$ in the supply fluid, and pressure sensor $P_4$ provides pressure data at the surface. Other pressure sensors may be used to provide pressure data at any other desired place in the system 100. Additionally, the system 100 includes fluid flow
sensors such as sensor V that provides measurement of fluid flow at one or more places in the system.

Further, the status and condition of equipment as well as parameters relating to ambient conditions (e.g., pressure and other parameters listed above) in the system 100 can be monitored by sensors positioned throughout the system 100: exemplary locations including at the surface (S1), at the fluid circulation device 150 (S2), at the wellhead equipment 104 (S3), in the supply fluid (S4), along the umbilical 110 (S5), at the well tool 108 (S6), in the return fluid upstream of the fluid circulation device 150 (S7), and in the return fluid downstream of the fluid circulation device 150 (S8). It should be understood that other locations may also be used for the sensors S1-n.

The controller 170 for suitable for drilling operations can include programs for maintaining the wellbore pressure at zone 140 at under-balance condition, at at-balance condition or at over-balanced condition. The controller 170 includes one or more processors that process signals from the various sensors in the drilling assembly and also controls their operation. The data provided by these sensors S1-n and control signals transmitted by the controller 170 to control downhole devices such as devices 150-158 are communicated by a suitable two-way telemetry system (not shown). A separate processor may be used for each sensor or device. Each sensor may also have additional circuitry for its unique operations. The controller 170, which may be either downhole or at the surface, is used herein in the generic sense for simplicity and ease of understanding and not as a limitation because the use and operation of such controllers is known in the art. The controller 170 can contain one or more microprocessors or micro-controllers for processing signals and data and for performing control functions, solid state memory units for storing programmed instructions, models (which may be interactive models) and data, and other necessary control circuits. The microprocessors control the operations of the various sensors, provide communication among the downhole sensors and provide two-way data and signal communication between the drilling assembly 30, downhole devices such as devices 150-158 and the surface equipment via the two-way telemetry. In other embodiments, the controller 170 can be a hydro-mechanical device that incorporates known mechanisms (valves, biased
members, linkages cooperating to actuate tools under, for example, preset conditions).

For convenience, a single controller 170 is shown. It should be understood, however, that a plurality of controllers 170 can also be used. For example, a downhole controller can be used to collect, process and transmit data to a surface controller, which further processes the data and transmits appropriate control signals downhole. Other variations for dividing data processing tasks and generating control signals can also be used. In general, however, during operation, the controller 170 receives the information regarding a parameter of interest and adjusts one or more downhole devices and/or fluid circulation device 150 to provide the desired pressure or range or pressure in the vicinity of the zone of interest 140. For example, the controller 170 can receive pressure information from one or more of the sensors (S1-Sn) in the system 100.

As described above, the system 100 in one embodiment includes a controller 170 that includes a memory and peripherals 184 for controlling the operation of the fluid circulation device 150, the devices 154-158, and/or the bottomhole assembly 108. In Figure 1A, the controller 170 is shown placed at the surface. It, however, may be located adjacent the fluid circulation device 150, in the BHA 108 or at any other suitable location. The controller 170 controls the fluid circulation device to create a desired amount of ΔP across the device, which alters the bottomhole pressure accordingly. Alternatively, the controller 170 may be programmed to activate the flow-control devices 154-158 (or other downhole devices) according to programmed instructions or upon the occurrence of a particular condition. Thus, the controller 170 can control the fluid circulation device in response to sensor data regarding a parameter of interest, according to programmed instructions provided to said fluid circulation device, or in response to instructions provided to said fluid circulation device from a remote location. The controller 170 can, thus, operate autonomously or interactively.

During drilling, the controller 170 controls the operation of the fluid circulation device to create a certain pressure differential across the device so as to alter the pressure on the formation or the bottomhole pressure. The controller 170 may be programmed to maintain the wellbore pressure at a
value or range of values that provide an under-balance condition, an at-balance condition or an over-balanced condition. In one embodiment, the differential pressure may be altered by altering the speed of the fluid circulation device. For instance, the bottomhole pressure may be maintained at a preselected value or within a selected range relative to a parameter of interest such as the formation pressure. The controller 170 may receive signals from one or more sensors in the system 100 and in response thereto control the operation of the fluid circulation device to create the desired pressure differential. The controller 170 may contain pre-programmed instructions and autonomously control the fluid circulation device or respond to signals received from another device that may be remotely located from the fluid circulation device.

In certain embodiments, a secondary fluid circulation device 180 fluidically coupled to the return line 126 cooperates with the fluid circulation device 150 to circulate fluid through the fluid circulation system 120. In one arrangement, the secondary fluid circulation device 180 is positioned uphole or downstream of the fluid circulation device 150. Certain advantages can be obtained by dividing the work associated with circulating drilling fluid between two or more downhole fluid circulation devices. One advantage is that the power requirement (e.g., horsepower rating) for the fluid circulation device 150, which is disposed further downhole that the secondary fluid circulation device 180, can be reduced. A related advantage is that two separate power supplies can be used to energize each of the devices 150, 180. For instance, a surface supplied energy stream (e.g., hydraulic fluid or electricity) can be used to energize the secondary fluid circulation device 180 and a local (wellbore) power supply (e.g., fuel cell) can be used to energize the fluid circulation device 150. Additionally, different types of devices can be used for each of the devices 150, 180. For instance, a centrifugal-type pump may be used for the fluid circulation device 150 and a positive displacement type pump may be used for the secondary fluid circulation device 180. It should also be appreciated that the devices 150, 180 (with the associated flow control devices) can be operated to control fluid flow and pressure (or other parameter of interest) in specified or pre-determined zones along the wellbore.
32, thereby providing enhanced control or management of the pressure gradient curve associated with the wellbore 32.

In certain embodiments, a near bit fluid circulation device 182 in fluid communication with the bit 112 provides a local fluid velocity or flow rate that assists in drawing drilling fluid and cuttings through the bit 112 and up towards the fluid circulation device 150. In certain instances, the flow rate needed to efficiently clean the well bottom of cuttings and drilling fluid is higher than that needed to circulate drilling fluid in the wellbore. In one arrangement, the near bit fluid circulation device 182 is positioned sufficiently proximate to the bit 112 to provide a localized flow rate functionally effective for drawing cuttings and drilling fluid away from the bit 112 and into the return line 116. As is known, efficient bit cleaning leads to high rates of penetration, improved bit wear, and other desirable benefits that result in lower overall drilling costs. In one conventional arrangement, the surface pumps are configured to provide this higher pressure differential, which exposes the open hole portions of the wellbore 32 to potentially damaging higher drilling fluid pressures. In another conventional arrangement, the surface pumps are run to provide only the pressure needed to circulate drilling fluid at the cost of, for example, reduced rates of penetration. As can be appreciated, the near bit fluid circulation device 182 can be configured to provide a flow rate that efficiently cleans the bit 112 of cuttings while the fluid circulation device 150 provides the primary motive force for circulating drilling fluid in the fluid circulation system 120. The near bit fluid circulation device 182 can be operated in conjunction with or independently of the fluid circulation devices 150, 180. For instance, the near bit fluid circulation device 182 can have a dedicated power source or use the power source of the fluid circulation device 150. Additionally, as noted earlier, different types of devices can be used for each of the devices 150, 180, 182. It should therefore be appreciated that the near bit fluid circulation device 182 can be configured to provide a localized flow rate to optimize bit cleaning whereas the other fluid circulation devices 150,180 can be configured to optimize the lifting of the return fluid to the surface.

Referring now to Figure 4, there is schematically illustrated one exemplary well bore assembly 200 utilizing a bit 202 rotated by a downhole motor 204 and a fluid circulation device 206 driven by an associated motor
208. A power transmission line or conduit 210 supplies power to the motors 204, 208. Additionally, the wellbore assembly 200 includes a controller 212, a sensor 214 to measure one or more parameters of interest (e.g., pressure) of the return fluid 215 in the return line 126 (umbilical 110), and a sensor 216 to measure one or more parameters of interest (e.g., pressure) of the supply fluid 217 in the supply line 124 (annulus 91). In one arrangement, the motors 204, 208 are variable speed electric motors that are adapted for use in a wellbore environment. It should be appreciated that an electrical drive provides a relatively simple method for controlling the fluid circulation device. For instance, varying the speed of the electrical motor will directly control the speed of the rotor in the fluid circulation device, and thus the pressure differential across the fluid circulation device. For such motors, the power transmission line 210 can include embedded metal conductors provided in the umbilical 110 to convey electrical power from a surface location (not shown) to the motors 204, 208 and other equipment (e.g., the controller 212). Because electric motors are usually more efficient at higher speeds, a suitable fluid circulation device 206 can include a centrifugal type pump or turbine that likewise operate more efficiently at higher speeds. Other embodiments of motors can be operated by pressurized gas, hydraulic fluid, and other energy streams supplied from a surface location, such energy streams being readily apparent to one of ordinary skill in the art. Where appropriate, a positive displacement pump may be used in the fluid circulation device 206. In one mode of operation, the controller 212 receives signal input from the sensors 214, 216, as well as other sensors S1-S8 (Figure 3). The power transmission line 210 can be configured to carry communication signals for enabling two-way telemetric communication between a controller 242 and the surface as well as other downhole equipment. Based on the received sensor data, the controller 212 controls the motors 204, 208 to obtain a bit rotation speed and/or pump flow rate/pressure differential that optimizes one or more selected drilling parameters (e.g., rate of penetration). Other modes of operation have been previously discussed and will not be repeated.

It should be appreciated that Figure 4 illustrated merely one exemplary wellbore assembly. Other equally suitable arrangements can include a single motor (electric or otherwise) that drives both the bit and the fluid circulation
device. If the bit and pump are to rotate at different speeds, then a suitable speed/torque conversion unit (not shown) can be used to provide a fixed or adjustable speed/torque differential. Alternatively, multiple motors may be used to drive the fluid circulation device and/or the drill bit. By speed/torque conversion unit it is meant known devices such as variable or fixed ratio mechanical gearboxes, hydrostatic torque converters, and a hydrodynamic converters. The controller 212 can optionally be programmed to operate such a speed/torque conversion unit. Still other embodiments can include one or more devices that provide mechanical weight on bit; e.g., thrusters and anchor assemblies. As is known, thrusters can provide an axial thrusting force that urges a drill bit into a formation and thereby enhances bit penetration. Anchors typically engage a wellbore wall with retractable members such as pads to absorb the reaction force produced by the thruster. Thrusters and associated anchors are known in the art and will not be discussed in further detail. Moreover, if the umbilical 110 is drill string, then surface rotation of the drill string 110 can be used to either exclusively or cooperatively rotate the bit 202. Still further, in yet another embodiment not shown, a cross-flow sub proximate to the drill bit is used to channel fluid from the annulus into the umbilical. Thus, in a conventional manner, the drilling fluid exits the nozzles of the drill bit and enters the annulus with the entrained cuttings. Thereafter, the fluid and entrained cuttings are channeled into the umbilical by the cross-flow sub.

Referring now to Figure 5, there is schematically illustrated another exemplary wellbore assembly 230 utilizing a bit 232 rotated by a downhole motor 234 and a fluid circulation device 236 driven by an associated motor 238. A signal transmission line 240 enables two-way telemetric communication between a controller 242 and the surface and can optionally be configured to transfer power in a manner described below. The wellbore assembly 230 also includes a sensor 244 to measure one or more parameters of interest (e.g., pressure) of the return fluid 215 in the return line (umbilical 110) and a sensor 246 to measure one or more parameters of interest (e.g., pressure) of the supply fluid 217 in the supply line 124 (annulus 91). Advantageously, the wellbore system 230 includes a downhole power unit 248 for energizing the motors 238, 234. In one arrangement wherein the
motors 238, 234 are electric, the power unit 248 supplies electrical power by converting a stored energy supply (e.g., a combustible fluid, hydrogen, methanol, or charges of compressed fluids) into electricity. For example, the power unit 248 can include a fuel cell or an internal combustion engine-generator set. The stored energy supply, in certain embodiments, is replenished from a surface source (not shown) via the line 240. The power supply can also include a geothermal energy conversion unit or other known systems for generating the power used to energize the motors 238, 234. In other arrangements wherein the motor 238, 234 are hydraulic, a suitable hydraulic fluid can be stored in the power unit 248. Moreover, an intermediate device, such as an electrically-driven pump, can be used to pressurize and circulate this hydraulic fluid.

It should be understood that the Figure 4 and 5 arrangements can readily be modified to include any or all of the earlier described features; e.g., a plurality of fluid circulation devices positioned serially or in parallel along the return line.

It will be appreciated that many variations to the above-described embodiments are possible. For example, bypass devices, cross-flow subs and conduits (not shown) can be provided to selectively channel fluid around the fluid circulation device. The fluid circulation device is not limited to merely positive displacement pumps and centrifugal type pump. For example, a jet pump can be used. In an exemplary arrangement, a portion of the supply fluid is accelerated by a nozzle and discharged with high velocity into the return line, thereby effecting a reduction in annular pressure. Pumps incorporating one or more pistons, such as hammer pumps, may also be suitable for certain applications. Additionally, a clutch element can be added to the shaft assembly connecting the drive to the pump to selectively couple and uncouple the drive and pump of a fluid circulation device. Further, in certain applications, it may be advantageous to utilize a non-mechanical connection between the drive and the pump. For instance, a magnetic clutch can be used to engage the drive and the pump. In such an arrangement, the supply fluid and drive and the return fluid and pump can remain separated. The speed/torque can be transferred by a magnetic connection that couples
the drive and pump elements, which are separated by a tubular element (e.g., drill string).

While the foregoing disclosure is directed to the preferred embodiments of the invention, various modifications will be apparent to those skilled in the art. It is intended that all variations within the scope and spirit of the appended claims be embraced by the foregoing disclosure.
CLAIMS

WHAT IS CLAIMED IS:

1. A method for drilling a wellbore having a fluid circuit whereby a drilling fluid is supplied to a drill bit and the drilling fluid with entrained cuttings (the "return fluid") is returned from the drill bit to a surface location, the method comprising:
   (a) positioning a fluid circulation device in the return fluid, the fluid circulation device providing the primary motive force for flowing the return fluid from the drill bit to the surface location.

2. The method according to claim (1) wherein the fluid circuit includes a supply line and a return line, and further comprising:
   (a) supplying drilling fluid to the drilling assembly via the supply line; and
   (b) returning the return fluid to the surface location via the return line.

3. The method according to claim (2) wherein the supply line includes at least an annulus of the wellbore.

4. The method according to claims (2)-(3) wherein the return line includes one of (i) drill string, (ii) a coiled tubing, (iii) a casing, (iv) a liner, and (iv) a tubular member.

5. The method according to claims (1)-(4) wherein the fluid circulation device is selected from one of (a) a positive displacement pump, (b) a centrifugal type pump, (c) a Moineau-type pump, and (d) a jet pump.

6. The method according to claims (1)-(5) further comprising driving the fluid circulation device with a drive assembly selected from one of (a) a positive displacement drive, (b) a turbine drive, (c) an electric motor, (d) a hydraulic motor, and (e) a Moineau-type motor.

7. The method according to claims (1)-(6) further comprising reducing the size of cuttings entrained in the return fluid with a comminution device.

8. The method according to claims (2)-(7) further comprising positioning a pump in the supply line to providing a supplemental motive force for circulating the drilling fluid.

9. The method according to claim (8) wherein the supply line includes at least an annulus of the wellbore.
10. The method according to claims (1)-(9) further comprising energizing the fluid circulation device with one of (i) a fuel cell; (ii) hydraulic fluid; (iii) geothermal power; (iv) surface supplied electrical power; and (v) compressed gas.

11. The method according to claims (1)-(10) further comprising rotating the drill bit rotated by a motor that is operated by one of (i) a fuel cell; (ii) hydraulic fluid; (iii) geothermal power; and (iv) surface supplied electrical power.

12. The method according to claims (1)-(11) further comprising rotating the drill bit and driving the fluid circulation device with a same motor.

13. The method according to claims (1)-(12) further comprising providing a localized flow rate proximate to the drill bit that is functionally effective to wash the drill bit of cuttings.

14. The method according to claims (1)-(13) wherein the drilling assembly includes a drill bit, and further comprising: rotating the drill bit with a drill string at least partially formed of a liner.

15. The method according to claims (1)-(14) wherein the surface location is an offshore platform.

16. The method according to claims (1)-(15) further comprising positioning a secondary fluid circulation device in serial alignment with the fluid circulation device, the fluid circulation device and the secondary fluid circulation device cooperating to provide the primary motive force for flowing the return fluid from the drill bit to the surface location.

17. The method according to claim (1)-(16) further comprising operating the fluid circulation device substantially independent of drill bit rotation.

18. A system for drilling a wellbore, comprising:

   (a) a fluid circuit for supplying a drilling fluid to a drill bit and returning the drilling fluid with entrained cuttings (the "return fluid") from the drill bit to the surface; and

   (b) a fluid circulation device in the return fluid, said fluid circulation device providing the primary motive force for flowing the return fluid to the surface.

19. The system according to claim (18) wherein said fluid circuit includes a supply line for conveying drilling fluid to said drill bit and a return line for returning the return fluid to the surface.
20. The system according to claim (19) wherein said supply line comprises at least an annulus of the wellbore.

21. The system according to claims (19)-(20) wherein said return line comprises one of (i) drill string, (ii) a coiled tubing, (iii) a casing, (iv) a liner, and (iv) a tubular member.

22. The system according to claims (18)-(21) wherein said fluid circulation device is selected from one of (a) a positive displacement pump, (b) a centrifugal type pump, (c) a jet pump, and (d) a Moineau-type pump.

23. The system according to claims (18)-(22) wherein said fluid circulation device is driven by one of (a) a positive displacement drive, (b) a turbine drive, (c) a electric motor, (d) a hydraulic motor, and (e) a Moineau-type motor.

24. The system according to claims (18)-(23) further comprising a comminution device for reducing the size of cuttings entrained in the return fluid.

25. The system according to claims (19)-(24) further comprising a pump positioned in said supply line to provide a supplemental motive force for flowing the drilling fluid.

26. The system according to claims (19)-(25) wherein the supply line includes at least an annulus of the wellbore.

27. The system according to claims (18)-(26) wherein said fluid circulation device is driven by a drive assembly energized by one of (i) a fuel cell; (ii) hydraulic fluid; (iii) geothermal power; (iv) surface supplied hydraulic fluid; and (v) surface supplied electrical power.

28. The system according to claims (18)-(27) further comprising a motor coupled to the drill bit, said motor being operated by one of (i) a fuel cell; (ii) hydraulic fluid; (iii) geothermal power; (iv) surface supplied hydraulic fluid; (v) surface supplied electrical power, and (vi) compressed gas.

29. The system according to claim (18)-(28) wherein said drill bit is rotated by one of: (i) a drill string at least partially formed of a liner, and (ii) a motor for driving said fluid circulation device.

30. The system according to claims (19)-(29) further comprising:
   (a) a variable volume tank positioned proximate to a seabed floor, said tank supplying drilling fluid into said supply line; and
(b) an offshore platform adapted to receive the return fluid flowing through said return line.

31. The system according to claims (18)-(30) further comprising a secondary fluid circulation device in serial alignment with said fluid circulation device, said fluid circulation device and said secondary fluid circulation device cooperating to provide the primary motive force for flowing the return fluid from the drill bit to the surface location.

32. The system according to claims (18)-(31) further comprising an near bit fluid circulation device positioned proximate to said drill bit, said near bit fluid circulation device adapted to provide a localized flow rate functionally effective for cleaning the drill bit of cuttings.

33. The system according to claims (18)-(32) wherein said fluid circulation device is configured to operate independently of drill bit rotation.
INTERNATIONAL SEARCH REPORT

PCT/US 03/37190

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7 E21B21/08  E21B21/00

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

B. FIELDS SEARCHED
Minimum documentation searched (classification system followed by classification symbols)
IPC 7 E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)
EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

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Further documents are listed in the continuation of box C.

Patient family members are listed in annex.

Date of the actual completion of the international search: 5 April 2004

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European Patent Office, P.B. 5819 Patentlaan 2 NL–2280 HV Rijswijk
Tel. (31–70) 940-2040, TX 31 651 epos nl, Fax: (31–70) 340-3016

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page 1 of 2
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