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(54) Title: MOTOR INTEGRATED REAMER
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Abstract: In one aspect, an apparatus for use in a wellbore is disclosed that in one non-limiting embodiment may include a drive system coupled to a drill bit by a drive sub for drilling a wellbore, wherein the drive system has an associated bend for directional drilling of the wellbore, and a reamer driven by the drive sub, wherein the reamer reams a ledge formed at a transition from a larger diameter wellbore to a smaller diameter of the wellbore during directional drilling of the wellbore.
CROSS REFERENCE TO RELATED APPLICATIONS

This application claims the benefit of U.S. Application No. 14/076698, filed on November 11, 2013, which is incorporated herein by reference in its entirety.

BACKGROUND

1. Field of the Disclosure

[0001] This disclosure relates generally to drilling assemblies for drilling directional wellbore.

2. Background Of The Art

[0002] To obtain hydrocarbons, such as oil and gas, boreholes or wellbores are drilled by rotating a drill bit attached to a drill string end. A large proportion of the current drilling activity involves drilling deviated and horizontal wellbores (directional wellbores) for hydrocarbon production. Drilling systems include a drill string that has a drilling assembly (commonly referred to as bottomhole assembly or "BHA") that includes a drill bit attached to an end thereof. The BHA includes a number of sensors, such as pressure, temperature, vibration and azimuthal sensors (commonly referred to a measurement-while-drilling (MWD) sensors) and tools for determining various properties of the earth formation (commonly referred to as logging-while-drilling "LWD" tool). BHA often includes a directional drilling device, which may be a bent sub or force application devices, such as ribs. For directional drilling, the BHA typically includes a motor, such as a positive displacement motor, driven by a drilling fluid (also referred to herein as the "mud motor" or "drilling motor") to rotate the drill bit. Typically a bent sub is integrated in the motor. There are two operating modes for directional drilling with bent motors. The first is mode is the slide mode. In the slide mode, the drill string is not rotated. The motor drills a curved section (in-gauge hole). The bend generates a side force at the drill bit, deflecting the drill string. The second mode is the tangent mode. In the tangent mode, the drill string is rotated. The bend and the side force do not have a deflecting impact on the drill string. The motor drills straight ahead, but due to the bend, the hole is slightly oversized. If the next section is drilled in the slide mode, a ledge may be generated at the transition from the oversized hole to the in-gauge hole, which may cause a stabilizer commonly used on a bearing housing to hang up. This phenomenon has led to the use of slick motors, which however, provide less directional control.
[0003] The disclosure herein provides apparatus and methods that reduce or eliminates the ledge and, thus, the potential hanging of the bearing housing stabilizer.

SUMMARY OF THE DISCLOSURE

[0004] In one aspect, an apparatus for use in a wellbore is disclosed that in one non-limiting embodiment may include a motor coupled to a drill bit by a drive sub for drilling a wellbore, wherein the motor has an associated bend for directional drilling of the wellbore, and a reamer driven by the drive sub, wherein the reamer reams a ledge formed at a transition from a larger diameter wellbore to a smaller diameter of the wellbore during directional drilling of the wellbore.

[0005] In another aspect, a method of drilling a wellbore is disclosed that in one non-limiting embodiment may include: conveying a drilling assembly by a rotatable conveying member into a wellbore, the drilling assembly including a motor coupled to a drill bit, wherein the motor has an associated bend, a stabilizer, and a reamer downhole of the stabilizer; drilling the wellbore by rotating the drill bit by the rotatable conveying member and the motor to form a first section having a first size; and drilling the wellbore by rotating the drill bit by the motor only to form a second section of the wellbore, wherein transition from the first section to the second section includes a ledge; and utilizing the reamer to reduce the ledge to form the wellbore.

[0006] Examples of certain features of the apparatus and method disclosed herein are summarized rather broadly in order that the detailed description thereof that follows may be better understood. There are, of course, additional features of the apparatus and method disclosed hereinafter that will form the subject of the claims appended hereto.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] The disclosure herein is best understood with reference to the accompanying figures in which like numerals have generally been assigned to like elements and in which:

FIG. 1 is an elevation view of a drilling system that includes a motor integrated reamer according to one non-limiting embodiment of the disclosure drilling a wellbore;

FIG. 2 shows placement of the motor and reamer on a drill collar, according to one non-limiting embodiment of the disclosure;

FIG. 3 shows an isometric cut-away view of the mechanism for driving the rotor by the motor, according to one non-limiting environment of the disclosure; and

FIG. 4 shows a simplified cross-section view of the device shown in FIG. 3.
DESCRIPTION OF THE EMBODIMENTS

[0008] FIG. 1 is a schematic diagram of an exemplary drilling system 100 that includes a drill string 120 having a drilling assembly or a bottom hole assembly 190 attached to its bottom end. Drill string 120 is shown conveyed in a wellbore or borehole 126 being formed in a subsurface formation 195. The drilling system 100 includes a conventional derrick 111 erected on a platform or floor 112 that supports a rotary table 114 that is rotated by a prime mover, such as an electric motor (not shown), at a desired rotational speed. A tubing (such as jointed drill pipe) 122, having the drilling assembly 190 attached at its bottom end, extends from the surface to the bottom 151 of the borehole 126. A drill bit 150, attached to drilling assembly 190, disintegrates the geological formations when it is rotated to drill the borehole 126. The drill string 120 is coupled to a draw works 130 via a Kelly joint 121, swivel 128 and line 129 through a pulley. Draw works 130 is operated to control the weight on bit ("WOB"). The drill string 120 may be rotated by a top drive 114a rather than the prime mover and the rotary table 114.

[0009] In one aspect, the drill bit 150 is rotated by rotating the drill pipe 122. In another aspect, a drive system, such as downhole motor 160 (mud motor) disposed in the drilling assembly 190 is utilized to rotate the drill bit 150 alone or in addition to the drill string rotation. The drilling motor 160 includes a rotor that rotates a drive sub connected to the drill bit 150 (described later in reference to FIG. 2). Alternatively, the drive system may include any other suitable device, including, but not limited to, a turbine.

[0010] In one aspect, a suitable drilling fluid 131 (also referred to as the "mud") from a source 132 thereof, such as a mud pit, is circulated under pressure through the drill string 120 by a mud pump 134. The drilling fluid 131 passes from the mud pump 134 into the drill string 120 via a desurger 136 and a fluid line 138. The drilling fluid 131a from the drilling tubular 122 discharges at the borehole bottom 151 through openings in the drill bit 150. The returning drilling fluid 131b circulates uphole through the annular space or annulus 127 between the drill string 120 and the borehole 126 and returns to the mud pit 132 via a return line 135 and a screen 185 that removes the drill cuttings from the returning drilling fluid 131b. A sensor S1 in line 138 provides information about the flow rate of the fluid 131. Surface torque sensor S2 and a sensor S3 associated with the drill string 120 provide information about the torque and the rotational speed of the drill string 120. Rate of penetration of the drill string 120 may be determined from sensor S5, while the sensor S6 may
provide the hook load of the drill string 120. Other sensors may be utilized to provide information about other parameters of interest.

[0011] Still referring to FIG. 1, a surface control unit or controller 140 receives signals from downhole sensors and devices or tools via a sensor 143 placed in the fluid line 138 and signals from sensors Si-Sd and other sensors used in the system 100 and processes such signals according to programmed instructions provided by a program to the surface control unit 140. The surface control unit 140 displays desired drilling parameters and other information on a display/monitor 141 that is utilized by an operator to control the drilling operations. The surface control unit 140 may be a computer-based unit that may include a processor 142 (such as a microprocessor), a storage device 144, such as a solid-state memory, tape or hard disc, etc., and one or more computer programs 146 in the storage device 144 accessible to the processor 142 for executing instructions contained in such programs. The surface control unit 140 may further communicate with a remote control unit 148. The surface control unit 140 may process data relating to the drilling operations, data from the sensors and devices on the surface, data received from downhole devices and may control one or more operations of the drilling system 100.

[0012] Still referring to FIG. 1, the drilling assembly 190 may also contain formation evaluation sensors or devices (also referred to as measurement-while-drilling, "MWD," or logging-while-drilling, "LWD," sensors) various properties of interest, such as resistivity, density, porosity, permeability, acoustic properties, nuclear-magnetic resonance properties, corrosive properties of the fluids or the formation, salt or saline content, and other selected properties of the formation 195 surrounding the drilling assembly 190. Such sensors are generally known in the art and for convenience are collectively denoted herein by numeral 165. The drilling assembly 190 may further include a variety of other sensors and communication devices 159 for controlling and/or determining one or more functions and properties of the drilling assembly 190 (such as velocity, vibration, bending moment, acceleration, oscillations, whirl, stick-slip, etc.) and drilling operating parameters, such as weight-on-bit, fluid flow rate, pressure, temperature, rate of penetration, azimuth, tool face, drill bit rotation, etc. The drill string 120 further includes a power generation device 178 configured to provide electrical power or energy to sensors 165 and other devices 159 and other devices. A downhole controller 170 may be provided to process signals from the various sensors and devices in the drilling assembly 190 and to provide information about various parameters of interest and to provide two-way communication with the surface controller 140. In one aspect, the downhole controller 170 may include a processor 172, such
as a microprocessor, one or more storage devices 174, such as solid state memories, and programs 176 accessible to the processor 172 for executing instructions contained therein.

[0013] Still referring to FIG. 1, the drilling motor 160 includes a bend 180, known in the art, for drilling a deviated wellbore (directional drilling). Drilling motor 160 also includes a stabilizing device 182 on a housing 183 of the drilling motor 160 below the power section 155. The stabilizing device may include any suitable device known in the art, including, but not limited to, a stabilizer and kick pads. The power section 155 is connected to a drive sub (described later), which is connected to the drill bit 150. In one non-limiting embodiment, the drilling motor 160 further includes a reamer 185 below the stabilizer 182 to prevent or reduce the forming of a ledge during directional drilling described in more detail in reference to FIGS. 2-4.

[0014] FIG. 2 shows a section of the motor (160, FIG. 1) that includes the power section 155 that drives a drive sub 225 inside the stabilizer 182 and reamer 185. As shown in FIG. 2, the power section 155 includes an outer housing 212 that may be lined with an elastomeric stator 214 having a number of internal lobes 214a and a solid rotor 216 having external lobes 216a that rotate inside the stator 214. When a fluid 250, such as drilling fluid or drilling mud, under pressure is supplied to the motor 155, the fluid passes through cavities 218 formed between the stator 214 and the rotor 216, causing the rotor 216 to rotate. The rotor 216 is coupled to a drive sub 225 by a transmission element (not shown). The drill bit 150 is connected to the drive sub 225 via a box end, known in the art. In the particular configuration of the device of FIG. 2, the stabilizer 182 is provided below the power section 155 and the reamer 185 below or downhole of the stabilizer 182. The reamer 185 includes suitable cutters 240 configured to cut the rock formation. Cutters of various types are known in the art and are thus not described in any detail herein. In one configuration, the reamer 185 may have the shape of a ring, as shown in FIG. 2. The reamer 185, however, may be configured to have any other suitable shape and may include any one or more types of cutters, known in the art. In one aspect, the reamer 185 is rotated by a mechanism (also referred to herein as the "reamer drive" or "drive mechanism") operated by the power section 155 via the drive sub 225, as described below in more detail in reference to FIGS. 3 and 4.

[0015] FIG. 3 shows a cut-away view of a non-limiting embodiment of a reamer drive 300 driven by the power section 155 via the drive sub 225. FIG. 4 shows a simplified cross-section view of the device shown in FIG. 3. The drive sub 225 is connected to the rotor (216, FIG. 2) of the power section (155, FIG. 2) and, thus, it rotates as the motor rotates. The drive shaft is supported by axial bearings 327 (only downhole side bearings shown) and radial
bearings (not shown) of a bearing assembly 329 inside a housing 302 of the drilling motor 160. In one non-limiting embodiment, the reamer drive 300 includes a first or inner gear wheel 310 on the drive sub 225. The inner gear wheel has outer teeth 312 and it rotates when the drive sub 225 rotates. Thus, rotating the drive sub 225 by the motor rotates the inner wheel 310 and hence teeth 312. The reamer drive 300 also includes a second or outer gear wheel 330 disposed in a gear wheel housing 342 containing a number of seals 344, separating the drilling fluid 250 under high pressure inside the bearing assembly 329 from the drilling fluid 250 under lower pressure in the annulus. Thus, in one aspect, the reamer drive contains seals that the pressure level inside the bearing assembly from the pressure level inside the annulus between the reamer and the wellbore. In an alternative embodiment, the gear wheel housing 342 may be completely sealed from the drilling fluid 131 allowing to use a lubricant such as oil. The outer gear wheel 330 includes teeth 332 that on one end 332a engage with the teeth 312 of the inner gear wheel 310 and on the other end 332b engage with teeth 387 on the inside of the reamer 185. Thus, when the drive sub 225 rotates, the inner wheel 310 on the drive sub 225 rotates, which rotates the outer wheel 330 and which in turn rotates the reamer 185. The ratio of the gears or teeth of inner gear wheel 310, the outer gear wheel 330 and the reamer 185 may be adjusted to provide a desired rotational speed (rpm) of the reamer 185 relative to the rotation of the drive sub 225. In one aspect, the gear wheel housing 342 includes one or more ports or fluid passages 350 on opposite sides 336a and 336b of the gear wheel housing 342 to allow for the flow of the drilling fluid or mud 250 through the reamer drive 300. Flow of the fluid 250 through the reamer drive 300 is shown by arrows 360. The seals 344 separate the pressure level inside the bearing assembly from the pressure in the annulus.

[0016] Thus, in one aspect, a motor integrated reamer 185 is disclosed that in one non-limiting embodiment may be disposed on or integrated in a bearing assembly 329 below a stabilizer 182. The reamer 185 also herein is referred to as the motor integrated reamer. In one aspect, the reamer 185 is rotated by the power section 155 via a first gear wheel 310 on the drive sub 225, which rotates a second gear wheel 330 engaged to an inner teeth on the reamer 185. The second gear wheel 330 sits inside a housing 342, but has mud ports 350 integrated in the gear wheel housing 342 to allow passage of a coolant through the bearing assembly. The cutters 240 on the downhole side of the reamer 185 ream the ledge formed at the transition of the over-gauge wellbore (wellbore formed when the drill string is rotating) to the in-gauge wellbore (wellbore formed when the drill string is not rotating). Once the reamer 185 and the stabilizer 182 have passed the ledge, the contact to the borehole is on the
stabilizer 182 and the reamer rotates idle, because the reamer outside diameter is less than the diameter of the stabilizer.

[0017] While the foregoing disclosure is directed to the certain non-limiting exemplary embodiments of the disclosure, 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

1. An apparatus for use in a wellbore, comprising:
a drive system coupled to a drill bit by a drive sub for drilling a wellbore, wherein the apparatus includes an associated bend for directional drilling of the wellbore; and
a reamer driven by the drive sub, wherein the reamer reams a ledge formed at a transition from a larger diameter wellbore to a smaller diameter of the wellbore during directional drilling of the wellbore.

2. The apparatus of claim 1 further comprising a reamer drive coupled to the drive sub that rotates the reamer as the drive sub rotates.

3. The apparatus of claim 2 further comprising a bearing section on the drive sub and wherein the reamer drive is placed on the bearing section.

4. The apparatus of claim 2, wherein the reamer drive comprises:
a first gear wheel coupled to the drive sub, wherein the first gear wheel rotates when the drive sub rotates; and
a second gear wheel coupled to the first gear wheel and the reamer, wherein the second gear wheel rotates when the first gear wheel rotates to cause the reamer to rotate.

5. The apparatus of claim 4, wherein rotational speed of the reamer is defined at least in part by sizes of the first gear wheel and the second gear wheel.

6. The apparatus of claim 1 further comprising:
a stabilizing device uphole of the reamer; and
wherein outside diameter of the reamer is equal to or less than outside diameter of the stabilizing device and less than outside diameter of the drill bit.

7. The apparatus of claim 4, wherein the reamer drive contains seals separating the pressure level inside the bearing assembly from the pressure level inside the annulus between the reamer and the wellbore.

8. The apparatus of claim 4, wherein the second gear is in a sealed housing with a lubricant therein.

9. The apparatus of claim 4, wherein the second gear wheel is placed inside a housing that is sealed to the inside of the bearing assembly and includes at least one mud port to allow passage of a coolant through the bearing assembly.

10. The apparatus of claim 9 further comprising additional seals to generate an encapsulated cavity for the gear wheels to contain a lubricant to provide lubrication to the reamer drive.
11. The apparatus of claim 1, wherein the drive system and the reamer are integrated into a drilling assembly.

12. A method of drilling a wellbore, the method comprising:
   conveying a drilling assembly by a rotatable conveying member into a wellbore, the drilling assembly including a drive system coupled to a drill bit, an associated bend, and a reamer downhole of the stabilizing device;
   drilling the wellbore by rotating the drill bit with the rotatable conveying member and the drive system to form a first section having a first size; and
   drilling the wellbore by rotating the drill bit by only the drive system to form a second section of the wellbore, wherein transition from the first section to the second section includes a ledge; and
   utilizing the reamer to reduce the ledge to form the wellbore.

13. The method of claim 12 further comprising determining one or more downhole parameters of interest during drilling of the wellbore and utilizing the determined one or more parameters of interest to form a deviated wellbore.

14. The method of claim 13, wherein the drilling assembly includes a stabilizing device and the outside diameter of the reamer is equal to or less than the outside diameter of the stabilizing device and less than the outside diameter of the drill bit.

15. The method of claim 13, wherein the reamer is driven by a reamer drive that includes:
   a first gear wheel coupled to the drive sub, wherein the first gear wheel rotates when the drive sub rotates; and
   a second gear wheel coupled to the first gear wheel and the reamer, wherein the second gear wheel rotates when the first gear wheel rotates to cause the reamer to rotate.
INTERNATIONAL SEARCH REPORT

A. CLASSIFICATION OF SUBJECT MATTER
E21B 10/26(2006.01)i, E21B 7/04(2006.01)i

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

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B 10/26; E21B 7/00; E21B 3/00; E21B 10/36; E21B 23/00; E21B 7/04

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & keywords: reamer, motor, drive sub, ledge, bearing section, stabilizing device

C. DOCUMENTS CONSIDERED TO BE RELEVANT

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Further documents are listed in the continuation of Box C. See patent family annex.

* Special categories of cited documents:
A document defining the general state of the art which is not considered to be of particular relevance
E earlier application or patent but published on or after the international filing date
L document may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
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"&" document member of the same patent family

Date of the actual completion of the international search 25 February 2015 (25.02.2015)

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