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[Continued on next page]

(54) Title: OPTIMIZATION OF DRILLING ASSEMBLY RATE OF PENETRATION

(57) Abstract: In drilling into a subterranean formation, several factors influence the rate of penetration, including, but not limited to, the type of formation being drilled, the weight on bit, and the rotational speed of the drill bit. Disclosed are a system and method for controlling the rotational speed of a drill bit based on regulation of fluid flow to the motor driving the bit, while maintaining at least a minimum flow of fluid to the annulus to clear debris from downhole during drilling. Regulation of fluid flow to the motor and to the annulus may be accomplished utilizing a flow diverter configured to adjust a flow ratio depending on drilling conditions in order to maximize efficiency of the motor downhole during drilling.

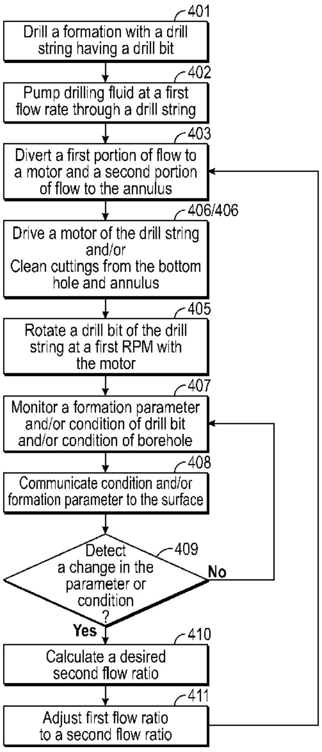

FIG. 4

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SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

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OPTIMIZATION OF DRILLING ASSEMBLY RATE OF PENETRATION

CROSS-REFERENCE TO RELATED APPLICATION

[0001] The present document is based on and claims priority to U.S. Provisional Application Serial No.: 62/132,575, filed March 13, 2015, which is incorporated herein by reference in its entirety.

BACKGROUND

[0002] A subterranean formation can be drilled with a drill string having a drill bit located on a distal end of the drillstring. A motor can be operatively coupled to rotate the drill bit. During drilling, the rate of penetration (ROP) may be used to measure how quickly the drill bit penetrates the formation. While several factors influence the ROP, the ROP primarily depends on the type of formation being drilled, the weight on bit (WOB), and the rotational speed (revolutions per minute (RPM)) of the drill bit. As the type of formation being drilled is predetermined, operators may vary the WOB and select a downhole motor with appropriate RPM capabilities to impact the ROP during operation.

[0003] The relationship between the WOB and RPM for a particular model and size of drilling motor can be represented by a power curve. The power curve is used to determine the energy delivered to the bit for a given WOB and RPM. Although other factors, for example, torque, vibration, fluid rheology, and other features of the fluid, may affect the power curve (as well as the ROP) WOB and RPM play stronger roles in defining a power curve for a given motor.

[0004] The WOB can be adjusted at the drill rig by putting more weight on the drill bit or carrying more of the weight of the drill string on the drill rig. However, adjusting the RPM during operation is not as straightforward. As noted above, drilling motors drive the rotation of the drill bit and determine the RPM of the drill bit. Motors, *e.g.*, mud motors, may be driven by drilling fluid pumped from surface equipment through the drillstring. The volume of fluid supplied to the mud motor is correlated to the speed, *i.e.*, RPM of the motor. For example, a higher flow rate of fluid provided to the motor will generally result in a greater RPM of the drill bit. However, the flow rate and RPMs of the motor generally have a parabolic relationship such that a range of peak efficiency for each motor exists, beyond which, providing greater fluid flow does not result in increased RPMs and may result in damage to the motor and/or bit. Similarly, too little fluid flow can stall a motor.

[0005] Additionally, drilling fluid provided to the drill string is used to clean away drill cuttings that accumulate in an annular space ("annulus") between the drill string, including the bottom hole assembly (BHA), and the wall of the borehole. When excessive amounts of cuttings build up in the annulus, the friction on the drill string increases with a corresponding increase of risk of the drill string becoming stuck in the borehole. In general, there is a minimum fluid flow necessary to effectively transport the cuttings up and out of the borehole. To prevent the drill string from becoming stuck, the ROP may be reduced until the excess cuttings are cleared away by the mud flow. In some cases, the flow of drilling fluid provided to the drill string is determined by the cleaning needs of the borehole rather than the RPM of the motor.

BRIEF DESCRIPTION OF DRAWINGS

[0006] FIG. 1 illustrates a drilling system in accordance with embodiments of the present disclosure.

[0007] FIG. 2 illustrates a flow diverter in accordance with embodiments of the present disclosure.

[0008] FIG. 3 illustrates an actuation system of a flow diverter in accordance with embodiments of the present disclosure.

[0009] FIGS. 4-7 depict flow diagrams for a method of drilling in accordance with the present disclosure.

DETAILED DESCRIPTION

[0010] Generally, embodiments disclosed herein relate to a method of drilling a subterranean formation. More specifically, the present disclosure relates to a method of drilling to optimize a rate of penetration (ROP) by adjusting a flow ratio of a first portion of fluid provided to a motor driving a drill bit and a second portion of fluid directed into an annulus between a drill string and the walls of the borehole to clear debris from the borehole.

[0011] Figure 1 shows a drilling system that may be used with methods disclosed herein. The drilling system includes a drill string 130, which may include a BHA 133 having a drill bit 137, a flow diverter 135, a motor 139, and monitoring tools 131, in various configurations and combinations. The motor 139 is coupled to the BHA 133, such that the motor 139 causes rotation of the drill bit 137. The drill string 130 may be suspended and moved longitudinally by a drilling rig 110 or similar hoisting device having a rotary table 122 or equivalent. The drill string 130 may be assembled from threadably coupled segments ("joints") of drill pipe or other forms of conduit. The drill string 130 may be disposed in a borehole 140 such that an annulus 120 is formed between the drill string 130 and the walls of the borehole 140.

[0012] The flow diverter 135 may be located in the drill string 130 above the motor 139, drill bit 137 and/or any measuring tools. The flow diverter 135 may be provided to divert at least a first portion of drilling fluid provided to the drill string 130 to the motor 139 and at least a second portion of drilling fluid to the annulus 120. The first portion of fluid, also referred to as BHA flow may be expelled through the bottom of the BHA 133 through the drill bit 137 to aid in clearing cuttings from the borehole 140. The fluid discharged through the BHA may enter the annulus 120 and flow upward. The second portion of drilling fluid may directed to annulus above the motor 139 in order to clear cuttings from the borehole 140.

[0013] The flow diverter 135 may split the flow on demand whilst deployed downhole, such that the ratio of the volume of the first portion of fluid to the second portion of fluid is in a range from 100:0 (*i.e.*, all flow is diverted to the motor 139) to 0:100 (*i.e.*, all flow is directed to the annulus 120). As used in this disclosure, the terms "first portion of fluid" and "BHA flow" are used to refer to the same stream of fluid, while the terms "second portion of fluid" and "bypass flow" are used to refer to the same stream of fluid. Additionally, the term "flow ratio" will refer to the ratio of BHA flow to bypass flow. One example of a flow diverter that may be used in accordance with embodiments disclosed herein is shown and described in U.S. Provisional Application No. 61/983501 and U.S. Provisional Application No. 61/944771, assigned to the assignee of the present application, and incorporated herein by reference in its entirety.

[0014] The motor 139 is provided to the drill string 130 to rotate the drill bit 137. The first portion of fluid provided to motor 139 drives the rotation of the motor. That is, the motor RPM is correlated to the flow rate of the first portion of fluid. As the RPM of the motor, as well as the RPM of the drill bit 137, is dependent on the flow rate of the first portion of fluid, both the pump rate of fluid from the surface and the flow ratio affect the motor 139 and drill bit 137 RPM. In some embodiments, the flow diverter 135 may be calibrated with the motor 139 and the drill bit 137 prior to drilling, such that, for a given pump rate of fluid flow rate from the surface, a given flow ratio will correspond to a particular RPM of the motor 139 and RPM of the drill bit 137. In other embodiments, a user or a control center may estimate the resulting RPM of the drill bit based on drilling conditions and motor data.

[0015] The BHA 133 is provided to a downhole end of the drill string 130 to control the geometry and direction of the borehole. The BHA 133 may include, for example, but not limited to, a drill bit 137, a plurality of nozzles, drill collars, a reamer, and/or a stabilizer (not shown). The plurality of nozzles may be located, for example, on a bottom face or side surface of the drill bit 137 to direct the first portion of fluid to the bottom hole and then upwards within the annulus 120 to clear away cuttings from the borehole.

[0016] The drill string 130 may also include a variety of monitoring tools. The monitoring tools may include, for example, but not limited to, measurement while drilling (MWD) tools, rotary steerable tools, and logging while drilling (LWD) tools. These tools may be provided to measure at least one parameter of the formation, for example, porosity, permeability and/or resistivity. The monitoring tools may be located in a measurement sub 131 or may be located at other points along the drill string 130, for example on the BHA 133 and/or motor 139. One skilled in the art will understand that placement of the monitoring tools is not intended to limit the scope of the present disclosure.

[0017] The monitoring tools 131 include communication devices (not separately shown) for transmitting various sensor measurements to the surface, *e.g.*, to a control center. These communication devices may include, but are not limited to, mud telemetry, wireline communication, wireless communication, and other downhole communication devices known in the art. The control center may include a computer having a processor. The computer may allow a user to monitor the conditions of the drill string, borehole, and the formation from the surface. The drill string may also receive command signals from the control center and/or user to actuate components of the drills string 130, *e.g.*, a reamer, the flow diverter 135, etc.

[0018] Referring to Figure 2, a flow diverter 135 may include at least a tubular housing 210, *e.g.*, a drill collar, a bypass element 220 located at a first end of the tubular housing 210, a choke housing 230 positioned within the tubular housing 210 below the bypass element 220, and an actuation system (300 in Figure 3) to control flow through the bypass element between a fully opened and fully closed position. The actuation system may also be in communication with the control center.

[0019] The flow diverter 135 may include an outer cavity 212 described by the space between the choke housing 230 and the drilling collar 210, through which the second portion of fluid may travel. The choke housing 230 includes, a plurality of chokes 231 located within the choke housing 230. An inner cavity 232 is described by the space between the plurality of chokes 231 and an inner wall of the choke housing 230 through which the first portion of fluid may travel. The bypass element 220, located near an upper end of the choke housing 230 may direct the flow to the inner cavity 232 and outer cavity 212, thereby splitting the flow into the first and second portions of flow, respectively.

[0020] The inner wall of choke housing 230 may include a plurality of choke seats 233 to receive each of the plurality of chokes 231. The plurality of chokes 231 operate between a fully open position, *i.e.*, flow ratio of 100:0, and a fully closed position, *i.e.*, flow ratio of 0:100. When the chokes 231 are seated in the choke seats 233, *i.e.*, flush against the choke seats 233, the chokes are in a fully closed position. When the chokes 231 have a maximum clearance between the plurality of chokes 231 and a corresponding choke seat 233, the chokes are in a fully open position. Each of the plurality of chokes 231 may be connected to an operating rod 235 so that the chokes 231 are actuated together.

[0021] The operating rod 235 may be coupled to the actuation system 300 shown in Figure 3. The actuation system 300 may be located in a tubular housing (210 in Figure 2) downhole from the choke housing 230 such that an annulus in fluid communication with the first portion of fluid flow is formed between the actuation system 300 and the tubular housing. The actuation system 300 may include at least actuation housing 320 a piston 321, a spring 323, and a valve assembly 325. The piston 321 may be biased in a first position by the spring 323, *e.g.*, in an up hole position. The valve assembly 325 may be in fluid communication with the piston 321 through flow line 326, for example flow line 326 may flow fluid to and/or remove fluid, *i.e.*, a relatively incompressible fluid, from an inner chamber 324 of the piston 321 to pressurize said inner chamber 324. The an upper end 322 of the piston 321 may be coupled to the operating rod 235 using coupling methods known in the art, such that an up hole position of the piston may correspond to an up hole position of the operating rod. One skilled in the art will understand, that although a limited number of embodiments have been described with respect to a flow diverter, other embodiments of a flow diverter may be used without departing from the scope of the present disclosure.

[0022] The drilling system illustrated in Figure 1 may be used to drill a formation in accordance with embodiments disclosed herein. Referring to Figures 1 and 4 together, a drilling system having at least a drill string 130 and a drill bit 137 may be used to drill 401 a formation. The drill string 130 may also include at least a motor 139 and/or a flow diverter 135. Drilling fluid may be pumped 402 from the surface through the drill string 130 at a first flow rate. The fluid pumped from the surface may be diverted 403 to the annulus 120 and/or a motor 139. For example, flow diverter 135 may divert 403 a first portion of fluid to the motor 139 and a second portion of fluid to the annulus 120.

[0023] When drilling commences the flow diverter 135 may be in a first position thereby resulting in a first flow ratio. For example, the first position of the flow diverter 135 may correspond to a flow ratio of 50:50, that is 50% of the flow from the surface is directed to the motor 139 and 50% of the flow from the surface is directed to the annulus 120. One skilled in the art will appreciate that the first position of the flow diverter 135 may be configured such that any flow ratio may be used, for example but not limited to 20:80, 80:20, or 100:0. The flow ratio may be determined, by, but not limited to, the type of formation being drilled, the type of drill bit being used, the WOB, minimum flow for clearing of debris from the borehole, and/or any combination listed herein. For example, a flow ratio for drilling a relatively hard formation, *e.g.*, limestone, may be higher, *i.e.*, less flow is diverted as bypass flow, than the flow ratio for drilling a relatively soft formation, *e.g.*, soft shale.

[0024] The first portion of fluid pumped through the motor may be forced through the motor 404 and energy from the flow of fluid is converted into rotational force, thereby driving the motor. The rotational force exerted by the motor rotates 405 the drill bit 137. The RPM of the motor 139 and consequently, the RPM of the drill bit 137 is directly correlated to the flow rate of fluid provided to the motor. Thus, when drilling commences, the drill bit 137 may rotate at a first RPM that corresponds to a first flow rate from the surface and a first flow ratio. Once the first portion of fluid has passed through the motor 139, said fluid may be directed to the borehole annulus 120 to aid in carrying cuttings up hole through the annulus 120. The second portion of fluid may be provided to the annulus 120 to further aid in clearing away 406 cuttings from the borehole.

[0025] During drilling, monitoring system 131 may monitor 407 at least one formation parameter. For example, an MWD system and/or LWD system may measure a density, porosity, resistivity, and/or other characteristics of the formation being drilled. It should be noted that some monitoring systems can make measurements of conditions ahead of a bit as well. In some embodiments, the monitoring system 131 may monitor a parameter of the drill string, for example, internal pressure, temperature, wear of cutting elements, orientation of the drill string, etc. The monitoring system 131 may communicate 408 the measurements (*i.e.*, at least one formation parameter and/or parameter of the drill string

130) to the surface, for example to a control center, with telemetry, wireline, a wireless system, and other communication systems known in the art.

[0026] The measurements from the monitoring system 131 may be monitored by the control system or a user to determine changes 409 in the formation. In some instances, changes in the at least one formation parameter, *e.g.*, porosity, resistivity, permeability, etc., may indicate that the type of formation has changed, for example, from a relatively hard formation, *e.g.*, limestone, to a relatively soft formation, *e.g.*, clay. As described above, the type of formation being drilled may influence a desired flow ratio and RPM of the drill bit. In other instances, monitoring conditions of a drill string, for example, a condition of the drill bit (*e.g.*, if a bit is worn), condition of a reamer, etc., may indicate a change in RPM is desirable.

[0027] In response to a change in a formation parameter (*e.g.*, a change in formation type) or condition of the drill string (*e.g.*, a change in the condition of the drill bit) and/or condition of the borehole (*e.g.*, increased accumulation of drill cuttings), the RPM of the drill bit may be adjusted 411 to a second RPM more suitable to accommodate the change in formation parameter or condition of the drill string. The change from a first RPM to a second RPM may be accomplished by adjusting the flow diverter 135 such that the first flow ratio is changed to a second flow ratio. For example, using a flow diverter 135 and actuation system 300 as shown in Figures 2 and 3, the axial position of chokes 231, and hence the flow ratio, may be adjusted by the actuation system 300. External forces, *e.g.*, forces from the first portion of fluid flow, may act to push the piston 321 in a downhole direction overcoming the biasing force of the spring 323. Valve assembly 325 may provide fluid to the inner chamber 322 such that a desired axial position of the piston 321 is maintained in the presence of external forces. Specifically, the amount of fluid in the inner chamber 322 of the piston may determine the axial position of the piston 322. The change in flow ratio may increase or decrease the volume of fluid flow to the motor 139, thereby adjusting the RPM of the motor 139 and, therefore, the drill bit 137. In addition to changing the flow ratio, the pump rate of fluid provided downhole may be adjusted to achieve the desired RPM.

[0028] The second flow ratio and the new pump rate may be estimated and/or calculated 410 by a user based on a desired second RPM. The desired second RPM may be determined based on the new conditions, *i.e.*, formation parameters and/or condition of the drill string and/or borehole. For example, if the type of formation has changed, a power curve for the drill bit and the new formation may be used to determine a RPM and WOB for the drill bit 137. The WOB may be adjusted at the drill rig, while the new pump rate and second flow ratio may be communicated to the appropriate equipment, *i.e.*, surface pumps and flow diverter 135, respectively. This allows the bypass flow rate to be changed without affecting the desired BHA flow rate.

[0029] According to some embodiments, the control center may calculate 410 a second RPM and second flow ratio. The control center may perform these calculations with, for example, software specifically configured to perform ROP optimization. The second RPM may also be calculated by the control center using a power curve. The measurements received by the control center from the measurement tools are used as inputs to calculate the desired second RPM. The control center may then communicate with the flow diverter 135 and the surface pumps to affect the flow ratio and pump rate, respectively, to achieve the desired second RPM, while maintaining a desired bypass flow rate.

[0030] Prior to adjusting the first flow rate and, consequently, the amount of fluid directed and/or diverted to the motor and first RPM, drilling may be stopped. The drilling may be stopped for example once a new formation has been detected, when the cutters on the drill bit are determined to be substantially worn, when the drilling is halted to add more joints of drill pipe to the borehole, and/or once a new desired RPM has been determined.

[0031] The user control center and/or user may communicate the second flow ratio to the drill string 130. For example, the control center may automatically send a signal to the drill string to adjust the first RPM to the calculated second RPM. More specifically, the control center may send the signal to the flow diverter 135 to adjust the flow ratio, thereby affecting the volume of fluid directed to the motor 139. In another example, a user may send the signal to the drill string 130 to adjust the first RPM to the second

RPM. Once the flow diverter 135 has been adjusted, fluid may once again be pumped downhole to resume drilling. The pump rate of the fluid provided downhole may be different than an initial pump rate. The control center and/or user may communicate with the drill string using, for example, telemetry, wireline, and/or wireless communication devices.

[0032] Embodiments described herein may provide for an improved ROP by manipulating an RPM of the drill bit without impacting the amount of fluid provided to the BHA for clearing away cuttings. In other words, the increase or decrease of fluid provided to the motor is independent of the amount of fluid directed to the BHA. Further, by including a flow diverter to divert flow away from the BHA and to the motor, a greater volume of drilling fluid may be provided to the drill string to increase an RPM of the motor without exceeding pressure limits of the drill string.

[0033] Referring now to Figure 5, in one embodiment, a method of drilling includes drilling a formation with a drill string having a drill bit that rotates at a first RPM 501. During drilling, at least one formation parameter may be monitored 502. In response to a change in the at least one formation parameter 503, the first PRM may be adjusted to a second RPM 504.

[0034] Referring now to Figure 6, in another embodiment, a method of drilling includes drilling a formation with a drill string 601. The drill string may include a drill bit, a motor, and a flow diverter located therein. During drilling, at least one parameter of the formation or condition of the drill string (*e.g.*, drill bit wear) and/or borehole may be monitored 602. Based on the monitored parameter or condition 603, the flow diverter may be adjusted to increase or decrease fluid flow to the motor 604.

[0035] Referring now to Figure 7, in another embodiment a method of drilling includes pumping drilling fluid at a first flow rate through a drillstring 701. The drill string may include at least a drill bit and a motor located therein. The pumping of drilling fluid may cause the motor to rotate 702, thereby rotating the drill bit at a first RPM to engage and cut a formation 703. During drilling operations, the first RPM may be adjusted to a second RPM 704. This adjustment may be accomplished by adjusting the amount of fluid sent to the motor.

[0036] Although only a few example embodiments have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible in the example embodiments without materially departing from this invention. Accordingly, such modifications are intended to be included within the scope of this disclosure as defined in the following claims. Moreover, embodiments disclosed herein may be practiced in the absence of any element which is not specifically disclosed.

CLAIMS

What is claimed is:

1. A method comprising:
drilling into a formation with a drill string having a drill bit that rotates at a first rotational speed;
monitoring at least one formation parameter; and
adjusting the first rotational speed to a second rotational speed based on a change in the at least one formation parameter.

2. The method of claim 1, further comprising calculating the second rotational speed based on the change in the at least one formation parameter and adjusting according to the calculated second rotations per minute.

3. The method of claim 2, further comprising determining the second rotational speed based on a power curve of the motor.

4. The method of claim 1, wherein the at least one formation parameter is one of porosity, density, resistivity, and permeability.

5. The method of claim 1, further comprising splitting a fluid flow through the drill string with a flow diverter and diverting flow from a bottom hole assembly to an annulus between the drill string and a borehole wall.

6. The method of claim 5, wherein the adjusting further comprises directing a flow of drilling fluid with the flow diverter to increase or decrease an amount of drilling fluid flow to the bottom hole assembly.

7. The method of claim 1, further comprising stopping drilling prior to adjusting the first rotational speed of the drill bit and resuming drilling thereafter.

8. The method of claim 1, further comprising adjusting a first weight on bit to a second weight on bit.

9. A method comprising:
drilling into a formation with a drill string, the drill string having a drill bit, a motor, and a flow diverter;
providing a drilling fluid through the drill string to the drill bit;
monitoring at least one of: a parameter of the formation and a condition of the drill string; and
adjusting the flow diverter to increase or decrease fluid flow to the motor based on the monitored parameter.

10. The method of claim 9, wherein the adjusting includes diverting at least a portion of the drilling fluid to an annulus.

11. The method of claim 9, wherein the increase or decrease of fluid flow to the motor is inversely proportional to a fluid flow diverted to an annulus.

12. The method of claim 9, wherein the adjusting may be performed in response to a change in a condition of the bit.

13. The method of claim 9, wherein adjusting the flow diverter occurs once the flow diverter is below a rotary table.

14. A method comprising:
pumping drilling fluid at a first flow rate through a drillstring, the drill string having a motor and a drill bit;
rotating the drill bit with the motor at a first rotational speed to engage and cut a formation; and
adjusting the first rotational speed to a second rotational speed by adjusting the amount of fluid sent to the motor.

15. The method of claim 14, further comprising diverting fluid sent downhole to the motor with a flow diverter.

16. The method of claim 15, further comprising sending a signal to the flow diverter to adjust a flow ratio of the flow diverter thereby adjusting the rotational speed.

17. The method of claim 14, further comprising monitoring at least one parameter of a formation or condition of the drill string with a control center.

18. The method of claim 17, further comprising inputting the at least one parameter or condition into the control center and calculating a desired second rotational speed.

19. The method of claim 17, further comprising sending a signal from the control center to the drill string to automatically adjust the first rotational speed to the desired second rotational speed.

20. The method of claim 17, further comprising maintaining a desired flow rate to the drill bit while adjusting the first rotational speed.

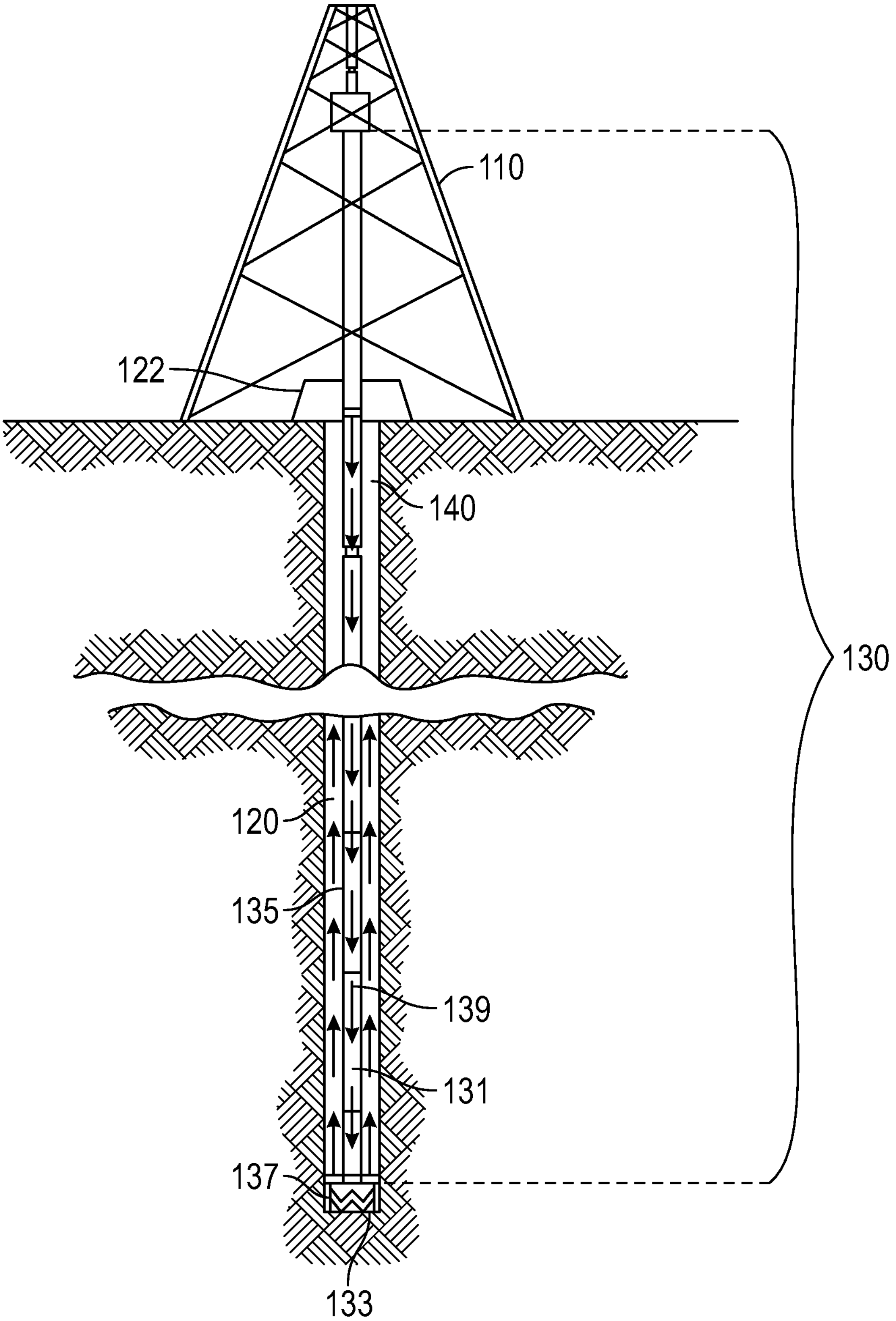

FIG. 1

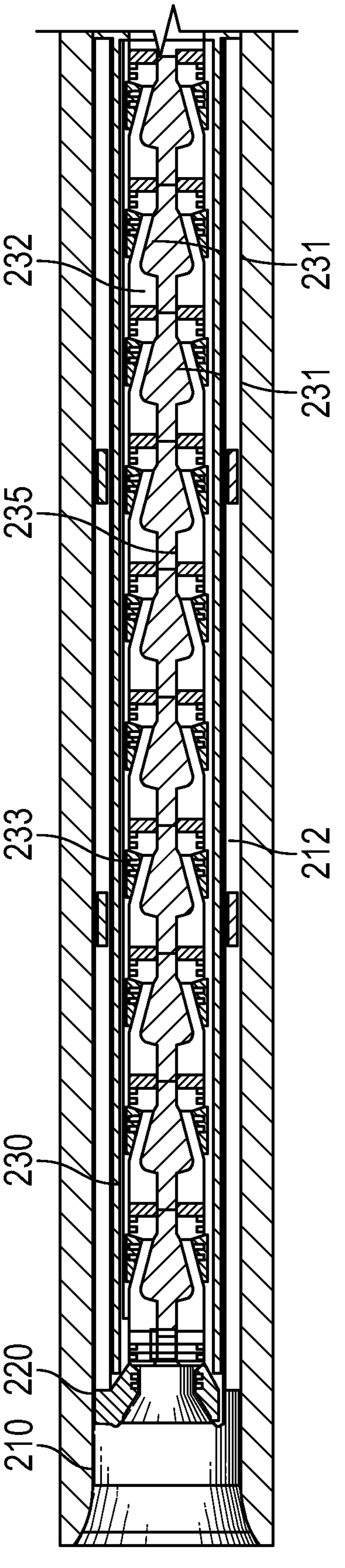
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FIG. 2

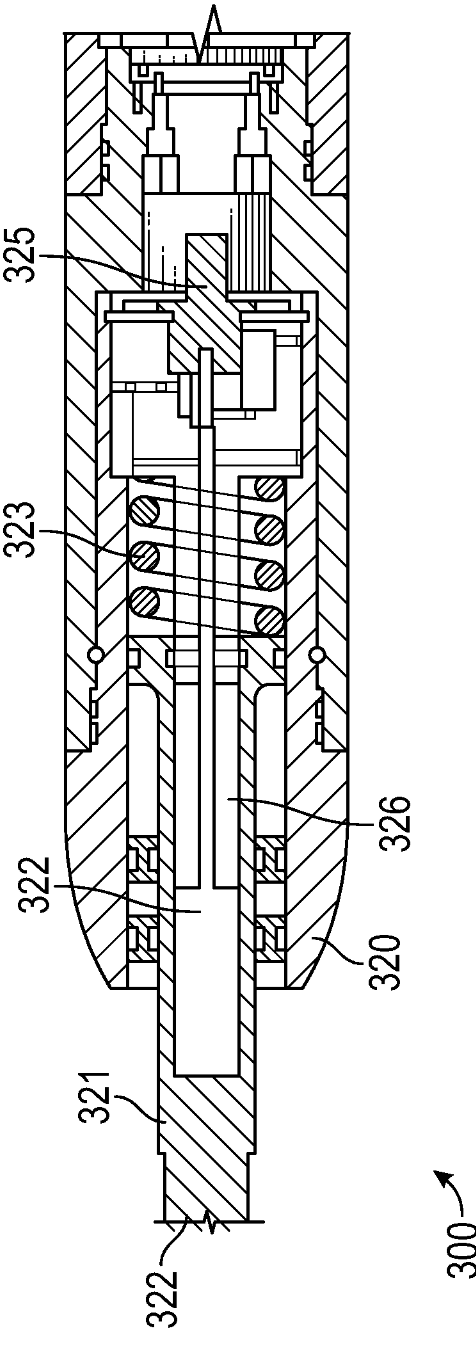
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FIG. 3

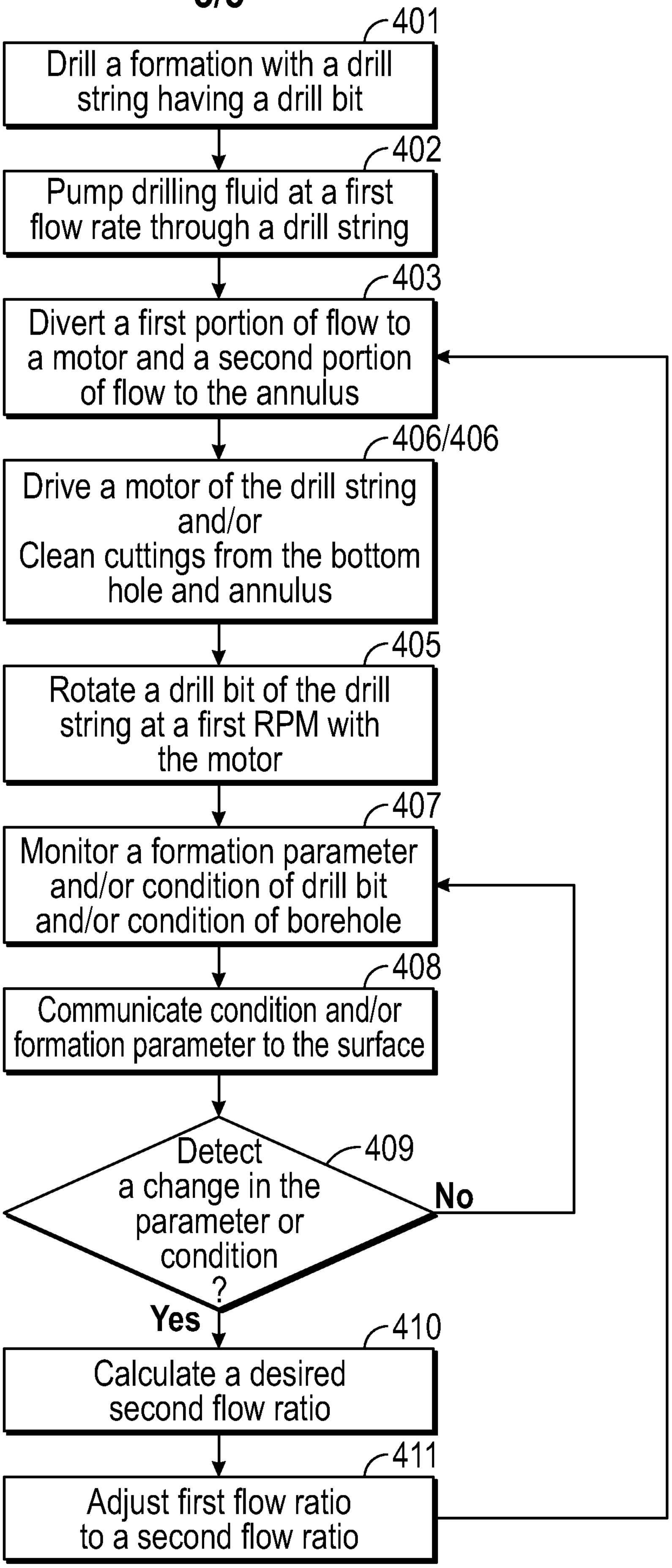
401
Drill a formation with a drill string having a drill bit
402
Pump drilling fluid at a first flow rate through a drill string
403
Divert a first portion of flow to a motor and a second portion of flow to the annulus
406/406
Drive a motor of the drill string and/or Clean cuttings from the bottom hole and annulus
405
Rotate a drill bit of the drill string at a first RPM with the motor
407
Monitor a formation parameter and/or condition of drill bit and/or condition of borehole
408
Communicate condition and/or formation parameter to the surface
409
Detect a change in the parameter or condition ?
No
Yes
410
Calculate a desired second flow ratio
411
Adjust first flow ratio to a second flow ratio

FIG. 4

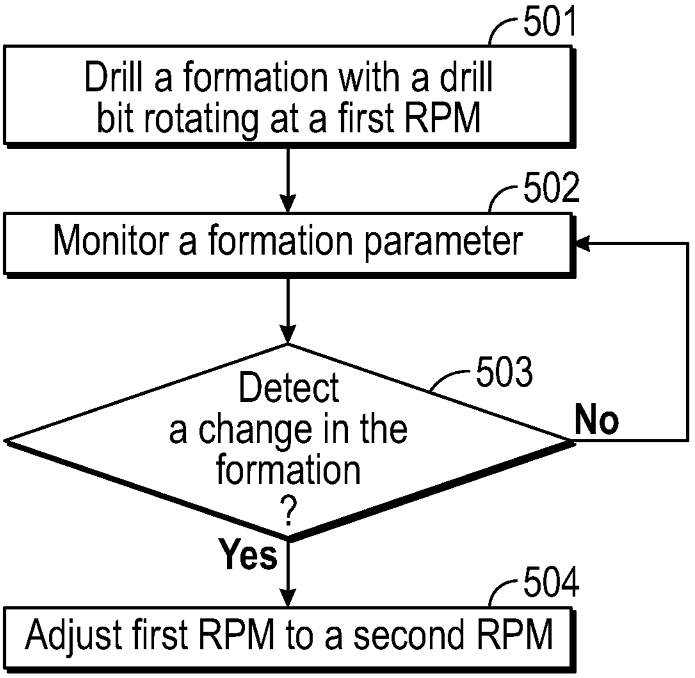
501
Drill a formation with a drill bit rotating at a first RPM
502
Monitor a formation parameter
503
Detect a change in the formation ?
No
Yes
504
Adjust first RPM to a second RPM

FIG. 5

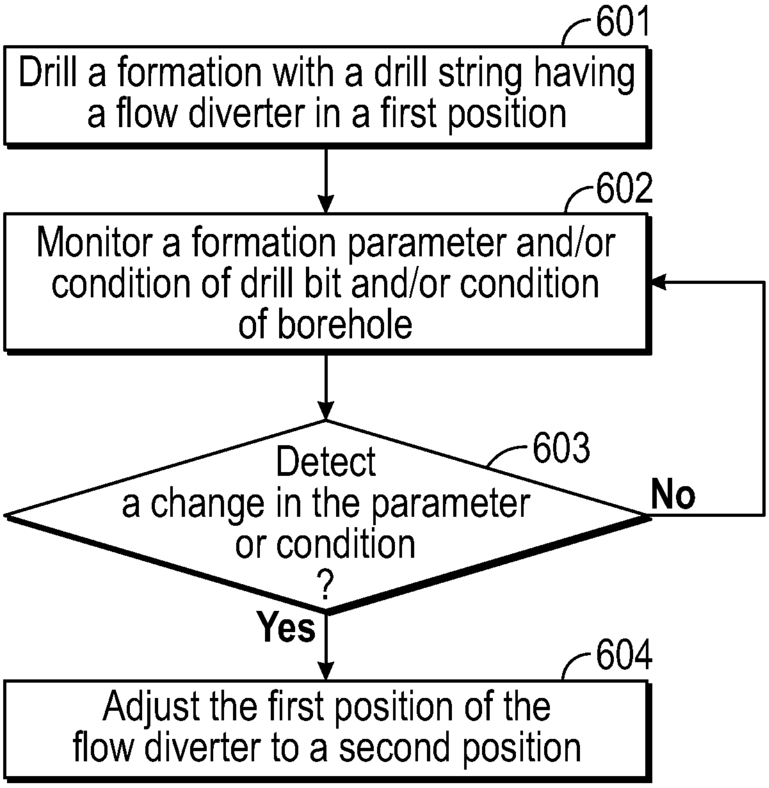
601
Drill a formation with a drill string having a flow diverter in a first position
602
Monitor a formation parameter and/or condition of drill bit and/or condition of borehole
603
Detect a change in the parameter or condition ?
No
Yes
604
Adjust the first position of the flow diverter to a second position

FIG. 6

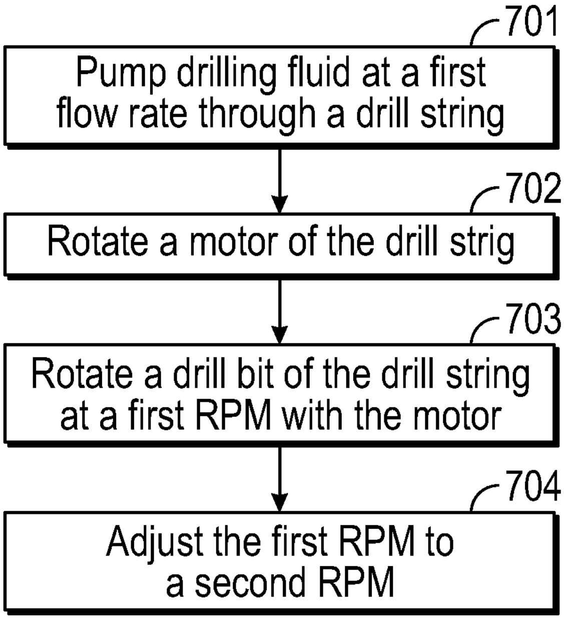
701
Pump drilling fluid at a first flow rate through a drill string
702
Rotate a motor of the drill strig
703
Rotate a drill bit of the drill string at a first RPM with the motor
704
Adjust the first RPM to a second RPM

FIG. 7

A. CLASSIFICATION OF SUBJECT MATTER

E21B 44/00(2006.01)i, G06F 19/00(2011.01)i, G05B 19/02(2006.01)i, E21B 21/08(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 44/00; E21B 4/02; E21B 44/04; F15B 11/04; E21C 5/00; E21B 21/08; G06F 19/00; G05B 19/02

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: formation parameter, drill string, motor, drill bit, flow diverter, drilling fluid and rotational speed

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2008-0164062 A1 (BRACKIN et al.) 10 July 2008 See paragraphs [0019]-[0022], [0040], [0048]-[0056], [0067]-[0068], claims 14-17, 24, and figures 1, 8.	1-20
A	US 2005-0211471 A1 (ZUPANICK, JOSEPH A.) 29 September 2005 See paragraphs [0020]-[0026] and figures 1-3.	1-20
A	US 2006-0124352 A1 (KRUEGER et al.) 15 June 2006 See paragraphs [0060]-[0065], [0076] and figures 1A, 4A-4D.	1-20
A	US 2003-0029308 A1 (VAN DRENTHAM-SUSMAN et al.) 13 February 2003 See paragraphs [0044]-[0049] and figures 1-3.	1-20
A	US 4660656 A (WARREN et al.) 28 April 1987 See column 3, line 10 - column 4, line 51 and figures 1-2.	1-20

☐ 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 which 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)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents,such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search 23 June 2016 (23.06.2016)	Date of mailing of the international search report **24 June 2016 (24.06.2016)**
Name and mailing address of the ISA/KR International Application Division Korean Intellectual Property Office 189 Cheongsa-ro, Seo-gu, Daejeon, 35208, Republic of Korea Facsimile No. +82-42-481-8578	Authorized officer RHEE, Jun Ho Telephone No. +82-42-481-8288

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