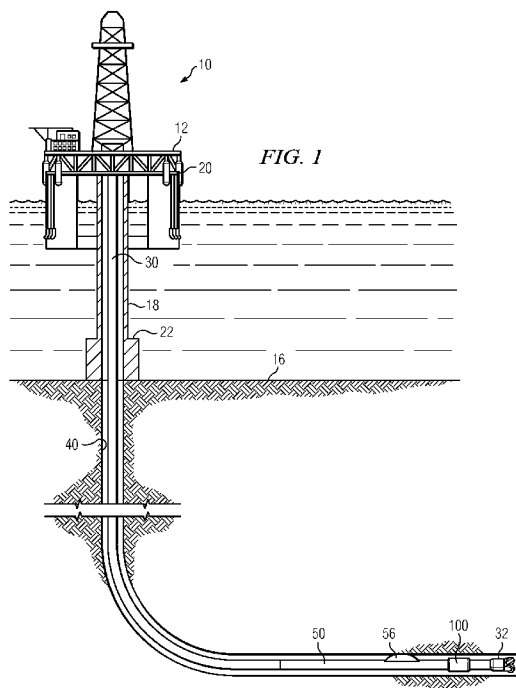




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(54) **Title:** DRILLING APPARATUS FOR REDUCING BOREHOLE OSCILLATION



(57) **Abstract:** A downhole drilling apparatus includes a drill bit, a steering tool, and an anti-oscillation sleeve deployed about a downhole end of the steering tool. The anti-oscillation sleeve is undergauge and is deployed axially between a first touch point at which the drill bit contacts the borehole wall and a second touch point at which the steering tool contacts the borehole wall.



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DRILLING APPARATUS FOR REDUCING BOREHOLE OSCILLATION

[0001] This application claims priority to and the benefit of a U.S. Non Provisional Patent Application having Serial No. 13/906,350, filed May 31, 2013, which is incorporated herein by reference.

FIELD

[0002] Disclosed embodiments relate generally to downhole drilling tools and more particularly to a drilling apparatus for reducing borehole oscillation and/or spiraling while drilling.

BACKGROUND

[0003] Directional control has become increasingly utilized in the drilling of subterranean oil and gas wells, with a proportion of current drilling activity involving the drilling of deviated boreholes. Such deviated boreholes often have complex profiles, including multiple doglegs and a horizontal section that may be guided through thin, fault bearing strata, and are utilized to more fully exploit hydrocarbon reservoirs. Deviated boreholes are often drilled using downhole steering tools, such as two-dimensional and three-dimensional rotary steerable tools.

[0004] As directional drilling operations and technology have advanced (and proliferated) increased attention is being given to the quality (or uniformity) of the borehole. Mechanical caliper measurements (both wireline and MWD measurements) indicate that many borehole quality issues are cyclic in nature. For example, borehole spiraling, rippling, and/or hour glassing are commonly observed in directional drilling

operations. It is widely recognized that poor borehole quality can cause various problems such as pack off, increased frictional forces leading to increased torque and drag, stick slip, degraded logging while drilling and wireline log quality, problematic casing runs, and unpredictable directional control during subsequent drilling. These problems tend to increase the costs associated with both drilling and subsequent completion operations.

[0005] A commercially available drilling-on-gauge (DOG) sub (available from Schlumberger) for providing at-bit reaming has been found to reduce borehole oscillation under certain drilling conditions. The DOG sub is intended to be deployed immediately above the drill bit in the lower portion of the bottom hole assembly (BHA). It therefore tends to add an extra length to the lower portion of the BHA and to reduce the dogleg severity that may be achieved by the BHA. There remains a need for an improved drilling apparatus for reducing cyclic borehole oscillations during drilling.

SUMMARY

[0006] A downhole drilling apparatus including an anti-oscillation sleeve is disclosed. The drilling apparatus includes a drill bit and a steering tool. The anti-oscillation sleeve is deployed about a downhole end of the steering tool body. The anti-oscillation sleeve is undergauge and located axially between a first touch point at which the drill bit contacts the borehole wall and a second touch point at which the steering tool contacts the borehole wall. In one embodiment, the drilling apparatus includes first, second, and third axially spaced anti-oscillation sleeves. In another embodiment, the drilling apparatus includes a single anti-oscillation sleeve having a concave outer surface. The first and second touch points and an outer surface of the anti-oscillation sleeve define an imaginary conical sectional surface that in turn defines a maximum theoretical dogleg that the drilling apparatus can deliver during a drilling operation.

[0007] The disclosed embodiments may provide various technical advantages. For example, the anti-oscillation sleeve at least partially occupies the annular space between the first and second touch points and has been found to reduce borehole oscillations (such as spiralling) during various drilling operations.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] For a more complete understanding of the disclosed subject matter, and advantages thereof, reference is now made to the following descriptions taken in conjunction with the accompanying drawings, in which:

[0009] FIG. 1 depicts one example of a rig on which a drilling tool having an anti borehole oscillation device may be deployed.

[0010] FIG. 2 depicts a known bottom hole assembly configuration.

[0011] FIG. 3 depicts one embodiment of a directional drilling apparatus including an anti-oscillation sleeve.

[0012] FIG. 4 depicts a directional drilling apparatus including an alternative anti-oscillation sleeve embodiment.

[0013] FIG. 5 depicts a directional drilling apparatus including another anti-oscillation sleeve embodiment.

[0014] FIG. 6 depicts a directional drilling apparatus including still another anti-oscillation sleeve embodiment.

[0015] FIGS. 7A and 7B (collectively FIG. 7) depict a directional drilling apparatus including yet another anti-oscillation sleeve embodiment.

[0016] FIG. 8 depicts a directional drilling apparatus including a further anti-oscillation sleeve embodiment.

[0017] FIG 9 depicts an alternative directional drilling apparatus including an anti-oscillation sleeve embodiment and a no gauge drill bit.

[0018] FIG 10 depicts another alternative directional drilling apparatus including a steerable drill bit and an anti-oscillation sleeve.

[0019] FIG. 11 depicts a flow chart of one disclosed method embodiment.

DETAILED DESCRIPTION

[0020] FIG. 1 depicts an example drilling rig 10 suitable for employing a directional drilling apparatus and various anti-oscillation sleeve embodiments disclosed herein. A semisubmersible drilling platform 12 is positioned over an oil or gas formation (not shown) disposed below the sea floor 16. A subsea conduit 18 extends from deck 20 of platform 12 to a wellhead installation 22. The platform may include a derrick and a hoisting apparatus for raising and lowering a drill string 30, which, as shown, extends into the borehole 40 and includes a directional drilling apparatus 80 deployed at the lower end of the bottom hole assembly (BHA) having a steering tool 50, a drill bit 32, and an anti-oscillation sleeve 100 deployed about a downhole end of the steering tool body.

[0021] It will be understood that the deployment illustrated on FIG. 1 is merely an example. Drill string 30 may include substantially any suitable downhole tool components, for example, including a downhole telemetry system, and one or more MWD or LWD tools including various sensors for sensing downhole characteristics of the borehole and the surrounding formation. The disclosed embodiments are by no means limited to any particular drill string configuration and may also be used in coiled tubing drilling operations.

[0022] It will be further understood that disclosed embodiments are not limited to use with a semisubmersible platform 12 as illustrated on FIG. 1. The disclosed embodiments

are equally well suited for use with either onshore or offshore subterranean operations. Moreover, it will be appreciated that the terms borehole and wellbore are used interchangeably herein.

[0023] FIG. 2 depicts a known BHA deployed in a subterranean borehole 40. The drill bit 32 includes a tapered lateral surface 34 and is threadably connected with a rotary steerable tool 50. The lower BHA contacts the borehole wall at first and second touch points 70A and 70B, the first of which is a touch point between the drill bit cutting surface or tapered lateral surface 34 and the borehole wall and the second of which is a touch point between a rotary steerable pad 52 and the borehole wall. In the schematic depiction of FIG. 2, an imaginary conical sectional surface 70 is shown. The conical sectional surface 70 includes the first and second touch points 70A and 70B as well as a surface point 70C on the body section of the steering tool 50 axially between the two touch points 70A and 70B. The depicted conical sectional surface 70 defines a theoretical maximum dogleg that the lower BHA can deliver (e.g., 20 degrees per 100 feet of measured depth). At the maximum dogleg the surface point 70C on the steering tool 50 contacts the borehole wall and thereby prevents further curvature of the borehole.

[0024] One aspect of the disclosed embodiments is the realization that a lower BHA having a theoretical maximum dogleg greater than (or much greater than) the maximum dogleg in any particular drilling operation can lead to the aforementioned oscillations during drilling. Stated another way it was realized that such a BHA can be unstable while drilling various sections and therefore may have a propensity to oscillate (e.g., spiral). While certain drill bit configurations may reduce the propensity to oscillate, they do not provide a solution to the problem. Another aspect of the disclosed embodiments is the realization that one potential solution to the aforementioned problem is to at least partially occupy the annular space between the first and second touch points in the lower BHA

(e.g., between the drill bit and the steering tool pad). In this way the curvature of the imaginary conical sectional surface may be selected during the BHA design phase so as to correspond to (e.g., substantially match or exceed by some predetermined amount) the intended curvature of the borehole section to be drilled.

[0025] FIG. 3 depicts one disclosed embodiment of a lower BHA (also referred herein to as a drilling apparatus) deployed in a borehole. The depicted drilling apparatus is similar to the known embodiment depicted on FIG. 2 in that it includes a drill bit 32 having a tapered lateral surface 34 being threadably connected with a rotary steerable tool 50. FIG. 3 further depicts an anti-oscillation sleeve 100 threadably connected with an outer surface of the rotary steerable tool 50. The anti-oscillation sleeve is undergauge (in that it has an outer diameter less than the diameter of the drill bit cutting surface and therefore of the borehole) and is deployed at approximately the axial mid-point between the drill bit 32 and the pad 52.

[0026] The drilling apparatus depicted on FIG. 3 (including the anti-oscillation sleeve 100) defines imaginary conical sectional surface 170 as shown. The conical sectional surface 170 includes first and second touch points 170A and 170B at which the drill bit 32 and pad 52 contact the borehole wall. A third point 170C on the outer surface of the anti-oscillation sleeve defines the conical sectional surface (along with the first and second touch points). As described above with respect to FIG. 2, the depicted conical sectional surface 170 defines a theoretical maximum dogleg that the lower BHA can deliver. At the theoretical maximum dogleg the surface point 170C on the anti-oscillation sleeve 100 contacts the borehole wall and thereby prevents further curvature of the borehole. The outer surface of the sleeve 100 being extended radially outward from an outer surface of the steering tool 50 body reduces the theoretical maximum dogleg (e.g., from about 20 to about 10 degrees per 100 feet of measured depth).

[0027] FIGS. 4 and 5 depict alternative drilling apparatus embodiments including alternative anti-oscillation sleeve embodiments. FIGS. 4 and 5 are similar in that they each depict a drilling apparatus including a drill bit 32 having a tapered lateral surface 34 being threadably connected with a rotary steerable tool 50. These FIGS further depict undergauge anti-oscillation sleeves 200 and 300A, 300B, 300C threadably connected with an outer surface of the rotary steerable tool 50.

[0028] In the embodiment depicted on FIG. 4, anti-oscillation sleeve 200 has a tapered outer diameter such that the outer diameter at the axial midpoint 202 of the sleeve is less than the outer diameter at an axial end 204 of the sleeve. The employed taper may be linear (straight) or non-linear (curved). In the depicted embodiment the anti-oscillation sleeve has a concave outer surface 202 (from a vantage point external to the sleeve, i.e., looking at the outer surface of the sleeve from outside the sleeve). The concave surface curvature may be selected so as to correspond with a predetermined theoretical maximum dogleg 270 as depicted. In the depicted embodiment, the first and second touch points 270A and 270B and the outer surface 202 of the sleeve define the theoretical maximum dogleg 270. At the maximum dogleg, the surface 202 contacts the borehole wall thereby preventing further curvature of the borehole.

[0029] In the drilling apparatus embodiment depicted on FIG. 5, anti-oscillation sleeves 300A, 300B, and 300C define a concave outer surface in a piecewise fashion. In the depicted embodiment the anti-oscillation sleeves 300A, 300B, and 300C are axially spaced apart from one another with the second sleeve 300B being located at the approximate midpoint between the first and second touch points 370A and 370B. Moreover, the outer diameter of the first and third sleeves 300A and 300C are approximately equal to one another and greater than the outer diameter of the second sleeve 300B. The curvature defined by the outer surfaces of the sleeves 300A, 300B, and

330C may be selected so as correspond with a predetermined theoretical maximum dogleg (e.g., as described above with respect to FIG. 4). In the depicted embodiment, the first and second touch points 270A and 270B and the outer surfaces 302A, 302B, and 302C of the anti-oscillation sleeves 300A, 300B, and 300C define the theoretical maximum dogleg. At the maximum dogleg, the surface sleeves 300A, 300B, and 300C contact the borehole wall thereby preventing further curvature of the borehole.

[0030] In the embodiments depicted on FIGS. 4 and 5, the anti-oscillation sleeve 200 or sleeves 300A, 300B, and 300C have an axial length or a combined axial length (as in the case with a plurality of sleeves) greater than about one half of the distance between the first and second touch points. In this way the sleeve (or sleeves) occupy much of the annular space between the first and second touch points (i.e., between the drill bit and the pad or stabilizer touch point in the steering tool) and thereby tend also to reduce harmonic oscillations. In embodiments employing multiple anti-oscillation sleeves (as in FIG. 5), the first sleeve 300A may optionally be deployed at the midpoint between the first touch point 370A and the second sleeve 300B and the third sleeve 300C may optionally be deployed at the midpoint between the second touch point 370B and the second sleeve 300B. Such deployment may further reduce harmonic oscillations.

[0031] FIG. 6 depicts a drilling apparatus that employs still another alternative anti-oscillation sleeve embodiment. The drilling apparatus includes a steering tool 50, a drill bit 32, and an anti-oscillation sleeve 400 clamped between an axial face 54 of the downhole end of the steering tool body 54 and a drill bit shank 36. The sleeve 400 includes an inner ring portion 402 axially offset from an outer ring portion 404. The inner ring portion is sized and shaped for deployment between the steering tool body 54 and the drill bit shank 36 as depicted. The outer ring portion 404 is sized and shaped to fit snugly about the steering tool body 54 and has an undergauge outer diameter. The

combination of the first and second touch points and an outer surface of the ring portion 404 define the maximum theoretical dogleg as described above with respect to FIGS 3-4.

[0032] FIGS. 7A and 7B (collectively FIG. 7) depict a drilling apparatus that employs yet another alternative anti-oscillation sleeve embodiment. The drilling apparatus includes a steering tool 50, a drill bit 32, and an anti-oscillation sleeve 500 deployed about a lower portion of the steering tool body 54. In the depicted embodiment anti-oscillation sleeve 500 includes a piston mechanism 505 that enables the outer diameter of the sleeve to be adjusted while drilling. The piston may be actuated, for example, via spring bias or drilling fluid pressure. By adjusting the diameter the anti-oscillation sleeve 500 the theoretical maximum dogleg achievable by the drilling apparatus may thus also be adjusted. This in turn enables the degree of oscillation suppression to be adjusted in substantially real time while drilling.

[0033] FIG. 8 depicts a directional drilling apparatus including a further alternative anti-oscillation sleeve embodiment. The drilling apparatus includes a steering tool 50, a drill bit 32', and an anti-oscillation sleeve 600 that is integral with the drill bit. The integral sleeve portion 600 is located between the steering tool pad 52 and a full gauge surface of the drill bit 32'. The sleeve portion 600 has an undergauge outer diameter. The outer surface may tapered (as described above with respect to FIG. 4) or straight (as in FIG. 3). The combination of the first and second touch points and the outer surface of the sleeve 600 defines the maximum theoretical dogleg as described above with respect to FIGS 3-4. By integral it is meant that the drill bit and the sleeve form a single piece, e.g., in which there is no threaded connection between bit and the sleeve. In the depicted embodiment, the bit body, including the sleeve portion 600, is formed from a single metallic work piece and may therefore be said to be of a unitary construction.

[0034] With reference again to FIGS 3-8 it will be understood that the disclosed embodiments are not limited to any particular steering tool configuration. For example, substantially any suitable rotary steerable tool may be utilized. Various rotary steerable tool configurations are known in the art. Engagement of the blades with the borehole wall is intended to eccentric the tool body, thereby pointing or pushing the drill bit in a desired direction while drilling. A rotating shaft deployed in the outer housing transfers rotary power and axial weight-on-bit to the drill bit during drilling.

[0035] Other known rotary steerable systems fully rotate with the drill string (i.e., the outer housing rotates with the drill string). These systems make use of an internal steering mechanism that does not require contact with the borehole wall and enables the tool body to fully rotate with the drill string. The rotary steerable systems make use of mud actuated blades (or pads) that contact the borehole wall. The extension of the blades (or pads) is rapidly and continually adjusted as the system rotates in the borehole. The known system makes use of a lower steering section joined at a swivel with an upper section. The swivel is actively tilted via pistons so as to change the angle of the lower section with respect to the upper section and maintain a desired drilling direction as the bottom hole assembly rotates in the borehole.

[0036] The second touch points 70B, 170B, 270B, and 370B (the first touch points above the bit 32) may be provided by a force applying member (a pad or blade) in a push-the-bit rotary steerable system (e.g., as depicted on FIGS. 3-5). Alternatively, the second touch point may be provided by a full-gauge stabilizer (near bit stabilizer) in a point-the-bit rotary steerable system. In other embodiments the second touch point may be provided by a slightly undergauge stabilizer. The second touch point may also be provided by a slightly undergauge stabilizer in a steerable motor or a steerable turbine. The disclosed embodiments are not limited in these regards.

[0037] With continued reference to FIGS 3-8 it will be understood that the disclosed embodiments are not limited to any particular drill bit configuration. Drill bits that make use of substantially any suitable cutting structure or cutting elements may be utilized (e.g., including fixed cutter, polycrystalline diamond compact (PDC), and rotary cone drill bits). While the depicted embodiments show drill bits including a tapered lateral surface 34 (or bit gauge region) it will be understood that the disclosure is not limited in this regard. Both straight gauge (also referred to as a cylindrical gauge) and tapered gauge drill bits are known and used. While the disclosed embodiments are in no way so limited, cylindrical gauge drill bits may be utilized when drilling a straight section of a borehole as they tend to provide the greatest contact between the gauge region and the wall of the borehole. Such contact in turn tends to provide the increased stability. Tapered gauge drill bits may be utilized in drilling curved sections of the borehole as a cylindrical gauge may result in excessive frictional forces owing to the straight gauge section of the bit being forced into the borehole wall. The diameter of the tapered gauge region is often configured to decrease with increasing distance to the cutting face. The diameter may decrease linearly (a straight taper) or non-linearly (a curved taper). The profile of a tapered gauge region is commonly selected such that the drill bit may traverse a curved path without excessive frictional forces restricting drill bit rotation while at the same time providing sufficient (light) contact with the borehole wall so as to enable stabilization of the drill bit during drilling.

[0038] It will be understood that the diameter, axial length, and shape of the drill bit gauge may be selected so as to correspond with the the dimensions and shape of the anti-oscillation sleeve(s) (and the imaginary conical sectional surface defined by the sleeve, the drill bit, and the second touch point). For example, the outer diameter of the bit gauge may be selected so as to correspond with the diameter of a preselected region on the anti-

oscillation sleeve. Moreover, the use of one or more anti-oscillation sleeves may enable a shorter drill bit gauge to be utilized thereby resulting in the cutting elements being closer to the steering tool which in turn enables a higher dogleg to be achieved (an embodiment with no bit gauge is described in more detail below with respect to FIG. 9). A rock bit (three cone bit) is generally considered as a less (laterally) stable drill bit because it does not have a gauge structure like a PDC bit; however, with the use of the disclosed sleeve embodiments, such bits may be used make a stable steerable BHA. The use of one or more anti-oscillation sleeves may also enable the use of a drill bit having no gauge section with the sleeve(s) providing the gauge functionality. This tends to enable the use of a wider range of bits and may further enable the distance between the first and second touch points to be reduced (which may in turn increase the ability to drill high dogleg sections).

[0039] The anti-oscillation sleeves (or rings) may be coupled to the BHA using substantially any coupling mechanism. For example, as depicted on FIGS. 3-5, the sleeves 100, 200, 300A, 300B, and 300C may be threaded to an outer surface of the BHA between the drill bit 32 and the steering tool pad 52 (e.g., to an outer surface of the steering tool). However, the disclosed embodiments are not so limited. The sleeves may be coupled to the BHA, for example, via splines, pins, or screws. Irrespective of the coupling mechanism threadably connecting the drill bit 32 to the BHA tends to secure the sleeve in place such that it may not be removed from the BHA (without removing the drill bit). The sleeves may also be mounted in such a way that they are free to rotate with respect to the BHA.

[0040] While not depicted on FIGS 3-8 it will be understood that the outer surfaces of the sleeves 100, 200, 300A, 300B, and 300C may include axial or spiral junk slots so as to provide a flow path for drilling fluid to move uphole in the annulus. The outer surface

of the sleeves may further be hardened using substantially any known techniques in the art. For example, the surfaces may be heavily hard faced with a metallurgically applied tungsten carbide material. One hard facing material includes Colmonoy 88 manufactured by Wall Colmonoy having a hardness of RC 58-64. The outer surface of the sleeves may further include various wear protection measures, for example, the use of wear buttons or wear resistant coatings such as diamond or cubic boron nitride coatings, embedded natural or polycrystalline diamond, and the like. The disclosed embodiments are not limited in these regards.

[0041] Moreover, the outer surface of the sleeves may be fitted with a plurality of cutting elements so as to provide a reaming functionality. The cutting elements may be fabricated from a hard material such as tungsten carbide or other suitable materials such as polycrystalline diamond cutter (PDC) inserts, thermally stabilized polycrystalline (TSP) inserts, diamond inserts, boron nitride inserts, abrasive materials, and the like. PDC cutters may be embedded to enhance ledge-trimming capability. Such cutting elements may also have substantially any suitable shape including, for example, flat, spherical, or pointed.

[0042] FIG 9 depicts an alternative directional drilling apparatus including an anti-oscillation sleeve 100 embodiment and a no gauge drill bit 32''. The use of one of the anti-oscillation sleeve embodiments described herein (e.g., any one or more of the sleeves 100, 200, 300A, 300B, 300C, 400, 500, and the like) may enable the use of a no gauge drill bit 32'' (a drill bit having no lateral gauge). Using such a configuration reduces the axial distance between the cutting surface of the bit and the steering pad 52 and may therefore enable very high dogleg sections to be drilled without encountering troublesome borehole oscillations. The drilling apparatus embodiment depicted on FIG. 9 is similar to those described above with respect to FIGS 3-8 in that it includes an anti-oscillation

sleeve 100 deployed axially between a steering pad 52 of a steering tool 50 and a full gauge surface of the drill bit 32''.

[0043] While the aforementioned drilling apparatus embodiments make use of a steering tool such as a rotary steerable tool, it will be understood that the disclosure is not so limited. In alternative embodiments the drilling apparatus may include a stabilizer having a plurality of fixed stabilizer blades deployed axially uphole from a steerable drill bit. The anti-oscillation sleeve may be deployed axially between the fixed stabilizer blades and the steerable drill bit. Substantially any suitable steerable drill bit may be utilized in such embodiments. For example, steerable drill bit may include a pivoting or tilting head such that the cutting face of the drill bit tilts with respect to the longitudinal axis of the drill string. Example steerable drill bits are disclosed in U.S. Patents 7,779,933 and 8,235,145, which are incorporated by reference herein in their entirety. In such embodiments the cutting or gauge surface of the steerable drill bit defines the first touch point while the fixed stabilizer blades define the second touch point. The combination of the first and second touch points and an outer surface of the anti-oscillation sleeve defines the maximum theoretical dogleg achievable by the drilling apparatus (as described above).

[0044] FIG. 10 depicts a directional drilling apparatus including an alternative steerable drill bit 732 and an undergauge anti-oscillation sleeve 700. The steerable drill bit includes one or more steering pads 736 deployed in the lateral gauge surface 734 of the bit 732. The steering pads 736 in the bit 732 define the first touch point between the drilling apparatus and the borehole wall. A full gauge (or slightly undergauge) fixed stabilizer 710 is deployed above the drill bit 732 and defines the second touch point. The anti-oscillation sleeve 700 (or sleeves) may include any one or more of the sleeves 100, 200, 300A, 300B, 300C, 400, 500 described above with respect to FIGS 3-7 and may be

deployed, for example, at the approximate midpoint between the steering pads 732 and the fixed stabilizer 710. As in previously described embodiments, the anti-oscillation sleeve 700 is deployed axially between the first and second points (axially between the drill bit 732 and the fixed stabilizer 710 in the depicted embodiment). As described with respect to FIGS. 3-4 the combination of the first and second touch points and an outer surface of the sleeve 700 defines the maximum theoretical dogleg achievable by the drilling apparatus with the presence of the sleeve 700 being intended to reduce the theoretical maximum dogleg and thereby mitigate unwanted oscillations.

[0045] FIG. 11 depicts a flow chart of one disclosed method embodiment 800 for designing a lower BHA. The depicted embodiment includes assembling properties of a pre-existing BHA and a drill bit into a borehole propagation software package at 802. Well plan trajectory details are also assembled into the software package at 804. At 806 the borehole propagation software is used to simulate (model) borehole propagation responses (drilling performance) for the trajectory, rock properties, and range of drilling parameters. The model responses are then evaluated at 808 for evidence of borehole oscillations that are sufficient to cause steering limitations or excessive torque and drag (e.g., due to borehole pinching). At 810 the size, shape, and location of a borehole oscillation sleeve is computed such that maximum theoretical dogleg (the instantaneous curvature between the bit and the steering pad) is equal to the maximum value called for by the well plan plus some predetermined factor (e.g., 50%). The properties of the BHA in the borehole propagation software package are updated at 812 to include the anti-oscillation sleeve. The updated software is then used to re-simulate the borehole propagation responses at 814. These responses are again evaluated for evidence of borehole oscillations at 816. The process may be repeated until a suitable anti-oscillation sleeve size, geometry, and location is found. Moreover, the method may be executed in real

time during drilling in embodiments in which an adjustable diameter anti-oscillation sleeve is employed (e.g., as depicted on FIG. 7).

[0046] Although a drilling apparatus for reducing borehole oscillation and certain advantages thereof have been described in detail, it should be understood that various changes, substitutions and alternations can be made herein without departing from the spirit and scope of the disclosure as defined by the appended claims.

CLAIMS

What is claimed is:

1. A downhole drilling apparatus comprising:

a drill bit, the drill bit including a first touch point configured to contact a borehole wall;

a steering tool including a steering tool body, a downhole end of the steering tool body being connected with the drill bit, the steering tool including a second touch point configured to contact the borehole wall; and

an anti-oscillation sleeve deployed about the downhole end of the steering tool body, the anti-oscillation sleeve being located axially between the first touch point and the second touch point, the anti-oscillation sleeve having an outer diameter less than that of the drill bit at the first touch point and the steering tool at the second touch point.

2. The downhole drilling apparatus of claim 1, wherein the first touch point, the second touch point, and an outer surface of the anti-oscillation sleeve define an imaginary conical sectional surface that in turn defines a theoretical maximum dogleg that the downhole drilling apparatus can deliver.

3. The drilling apparatus of claim 1, wherein the anti-oscillation sleeve is deployed at the axial midpoint between the first touch point and the second touch point.

4. The drilling apparatus of claim 1, further comprising at least first, second, and third axially spaced anti-oscillation sleeves deployed about the downhole end of the steering tool body axially between the first touch point and the second touch point.

5. The drilling apparatus of claim 4, wherein the first, second, and third anti-oscillation sleeves have first, second, and third outer diameters, the first outer diameter being substantially equal to the third outer diameter, and the second outer diameter being less than the first outer diameter.

6. The drilling apparatus of claim 5, wherein the second anti-oscillation sleeve is deployed at the axial midpoint between the first touch point and the second touch point.

7. The drilling apparatus of claim 4, wherein the anti-oscillation sleeves have a combined axial length greater than about one half an axial distance between the first and second touch points.

8. The drilling apparatus of claim 1, wherein the anti-oscillation sleeve has a tapered outer diameter such that the outer diameter at an axial midpoint of the anti-oscillation sleeve is less than the outer diameter at an axial end of the anti-oscillation sleeve.

9. The drilling apparatus of claim 8, wherein the anti-oscillation sleeve has a concave outer surface from a vantage point external to the sleeve.

10. The drilling apparatus of claim 9, wherein a curvature of the outer surface is substantially equal to a theoretical maximum dogleg that the downhole drilling apparatus can deliver.

11. The drilling apparatus of claim 8, wherein the anti-oscillation sleeve has an axial length greater than about one half an axial distance between the first and second touch points.

12. The drilling apparatus of claim 1, wherein the anti-oscillation sleeve is threadably connected to the downhole end of the steering tool body.

13. The drilling apparatus of claim 1, wherein the anti-oscillation sleeve is clamped between an axial face of the downhole end of the steering tool body and a drill bit shank.

14. The drilling apparatus of claim 11, wherein the anti-oscillation sleeve comprises an inner ring portion axially offset from an outer ring portion, the inner ring portion being sized and shaped for deployment between the axial face of the downhole end of the steering tool body and the drill bit shank, the outer ring portion being sized and shaped to fit snugly about the steering tool body.

15. The drilling apparatus of claim 1, wherein the anti-oscillation sleeve further comprises a piston mechanism configured to enables an outer diameter of the anti-oscillation to be adjusted during a drilling operation.

16. A downhole drilling apparatus comprising:

a steerable drill bit including a cutting face and a lateral gauge portion, the steerable drill bit defining a first touch point with the borehole wall;

a stabilizer located axially uphole from the drill bit, the stabilizer including a tool body portion and a plurality of substantially full gauge fixed the stabilizer blades, the stabilizer blades defining a second touch point with the borehole wall; and

an anti-oscillation sleeve deployed about a downhole end of the stabilizer tool body, the anti-oscillation sleeve being located axially between the first touch point and the second touch point, the anti-oscillation sleeve having an outer diameter less than that of the drill bit at the first touch point and the stabilizer blades at the second touch point.

17. The downhole drilling apparatus of claim 16, wherein the steerable drill bit is configured to tilt with respect to the stabilizer tool body.

18. The downhole drilling apparatus of claim 16, wherein the lateral gauge portion of the steerable drill bit comprises at least one extendable member configured to extend radially outward from the drill bit into contact with a borehole wall, the extendable member defining the first touch point.

19. The downhole drilling apparatus of claim 16, wherein the first touch point, the second touch point, and an outer surface of the anti-oscillation sleeve define an imaginary conical sectional surface that in turn defines a theoretical maximum dogleg that the downhole drilling apparatus can deliver.

20. The drilling apparatus of claim 16, wherein the anti-oscillation sleeve is deployed at the axial midpoint between the first touch point and the second touch point.

21. The drilling apparatus of claim 16, further comprising at least first, second, and third axially spaced anti-oscillation sleeves deployed about the downhole end of the stabilizer tool body axially between the first touch point and the second touch point, and wherein the first, second, and third anti-oscillation sleeves have first, second, and third outer diameters, the first outer diameter being substantially equal to the third outer diameter, and the second outer diameter being less than the first outer diameter.

22. The drilling apparatus of claim 16, wherein the anti-oscillation sleeve has a tapered outer diameter such that the outer diameter at an axial midpoint of the anti-oscillation sleeve is less than the outer diameter at an axial end of the anti-oscillation sleeve.

23. A method for designing a downhole drilling apparatus, the method comprising:

- (a) assembling properties of a pre-existing bottom hole assembly and a drill bit into a borehole propagation software package;
- (b) assembling a well plan trajectory into the borehole propagation software package;
- (c) simulating drilling performance for the trajectory, formation properties, and a range of drilling parameters using the borehole propagation software package;
- (d) evaluating said simulation for evidence of borehole oscillations;

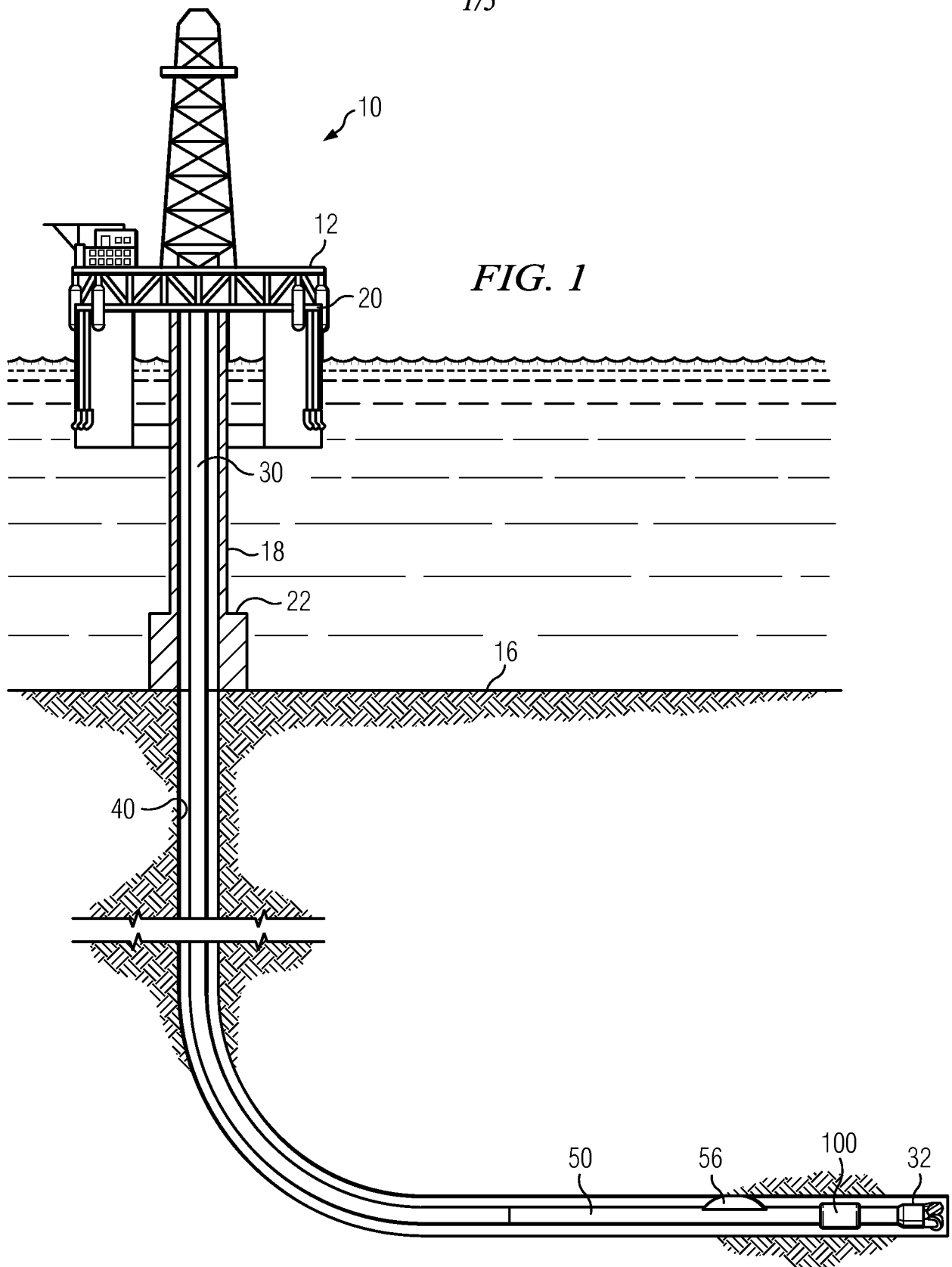
(e) computing a size, shape, and location of a borehole oscillation sleeve to achieve a predetermined maximum theoretical dogleg;

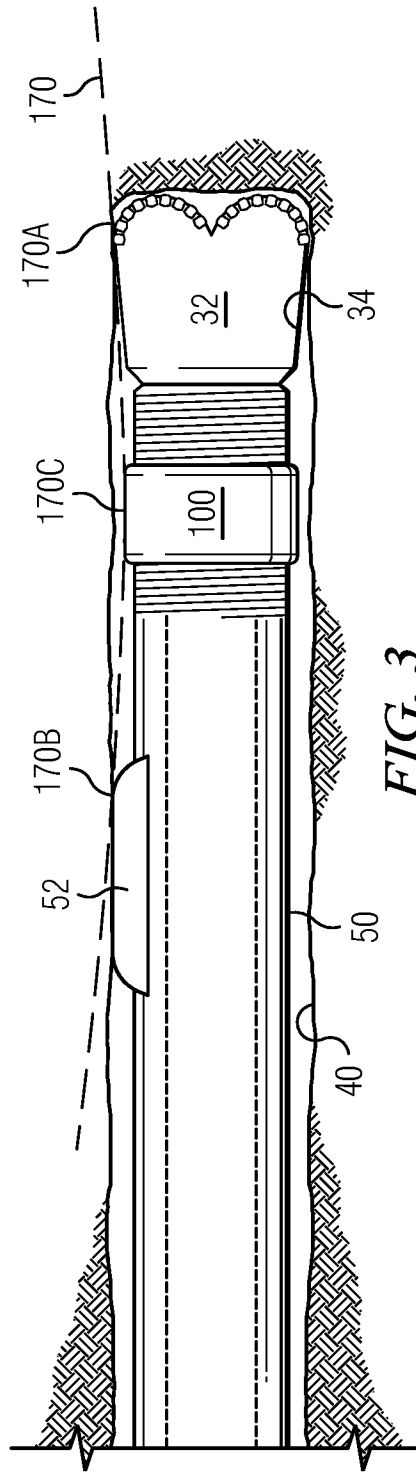
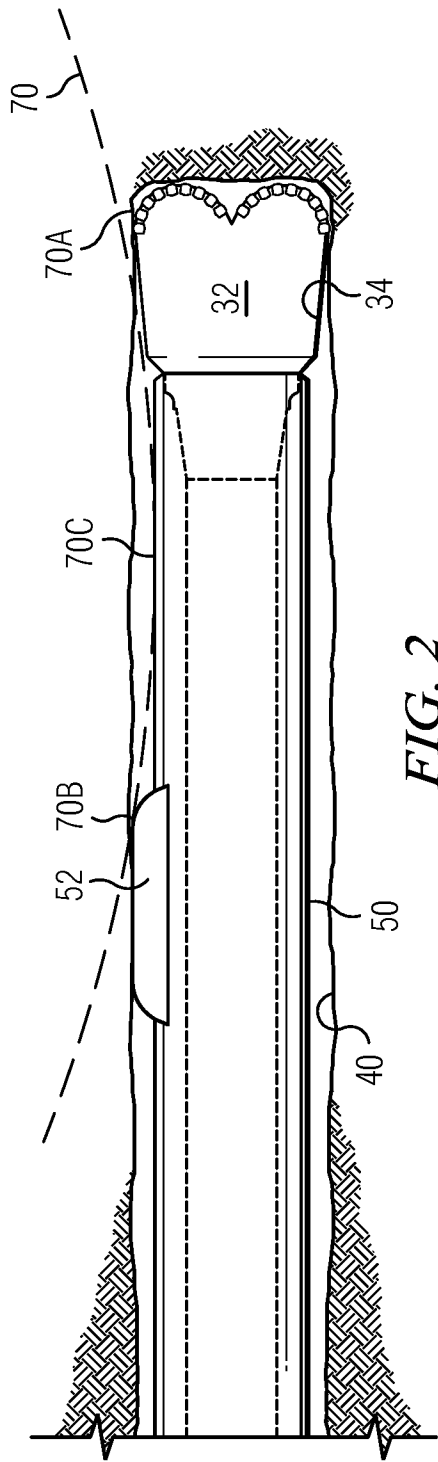
(f) updating properties of the bottom hole assembly in the borehole propagation software package;

(g) re-simulating drilling performance using said updated software package;
and

(h) evaluating said re-simulation for evidence of borehole oscillations.

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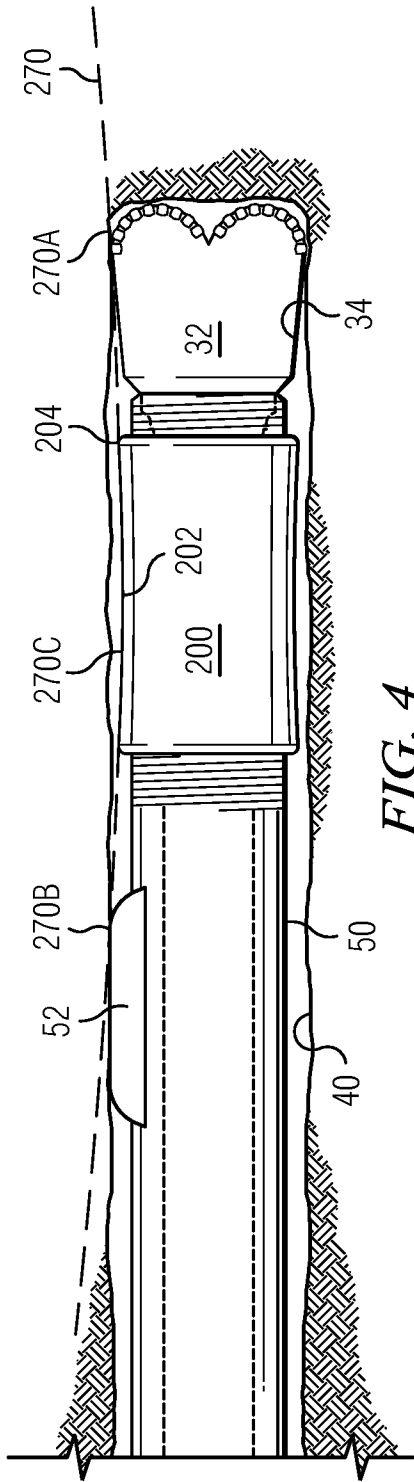


FIG. 4

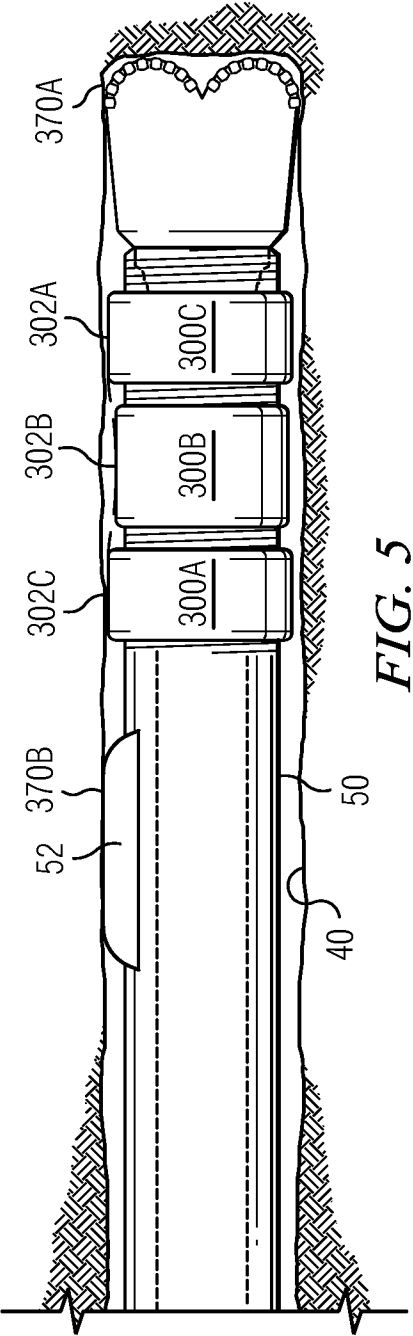
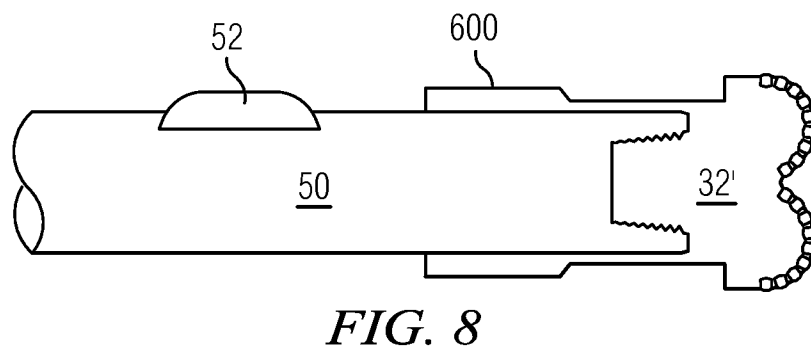
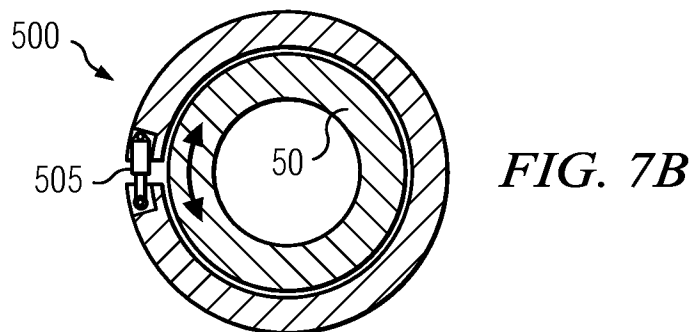
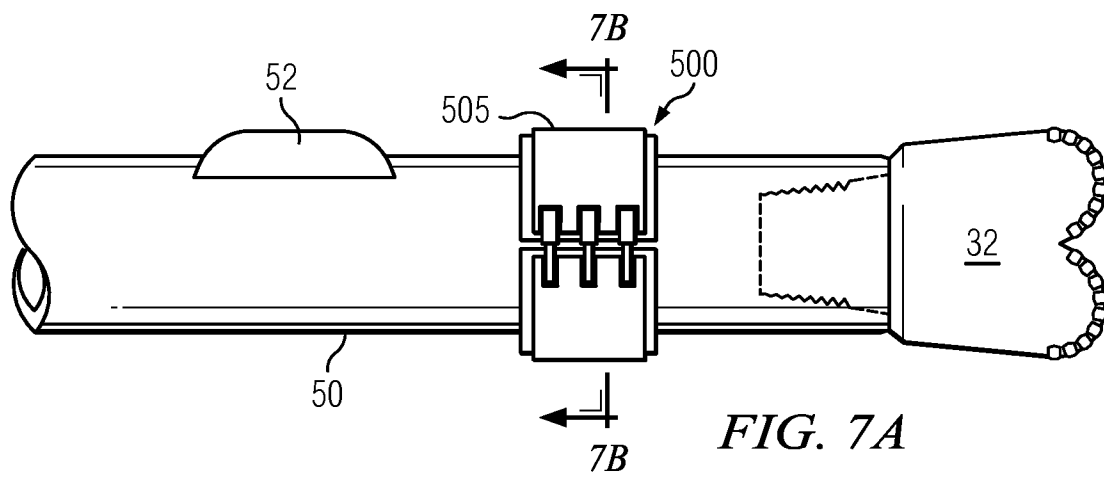
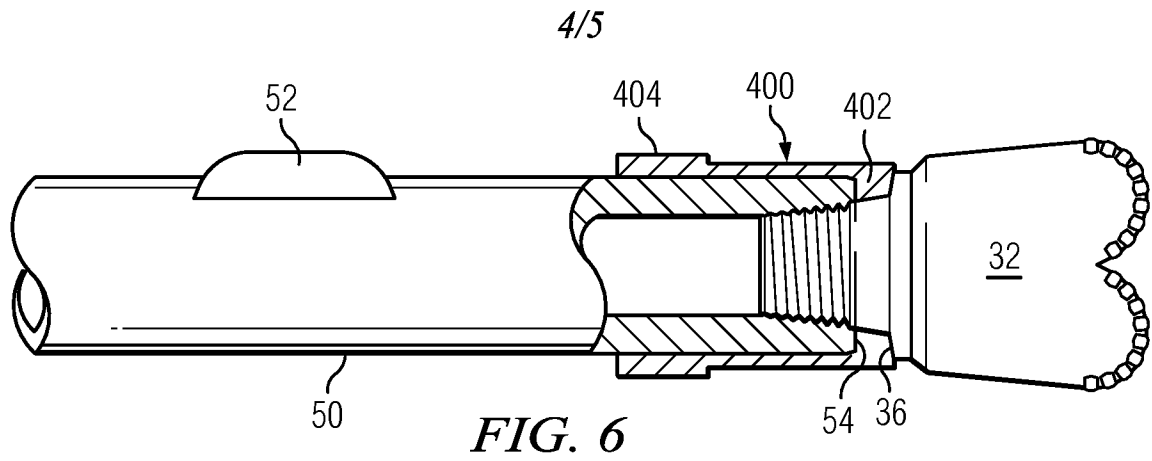
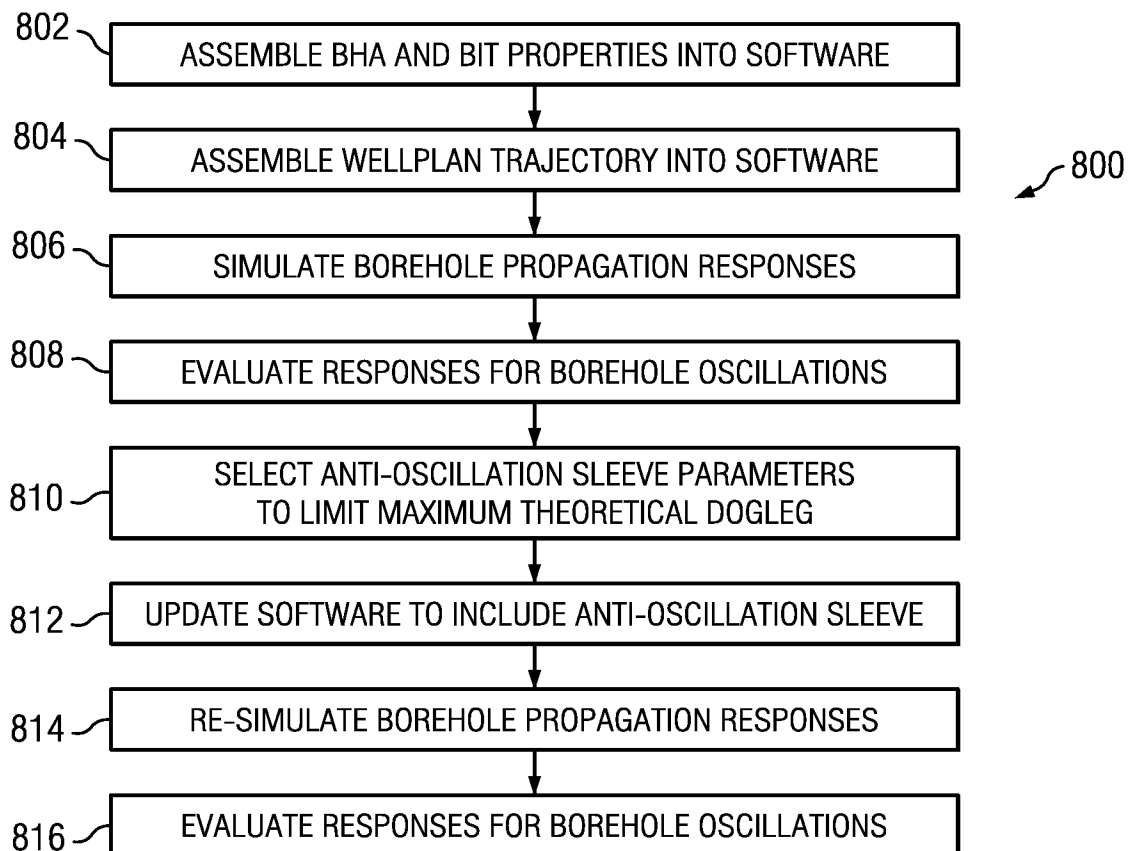
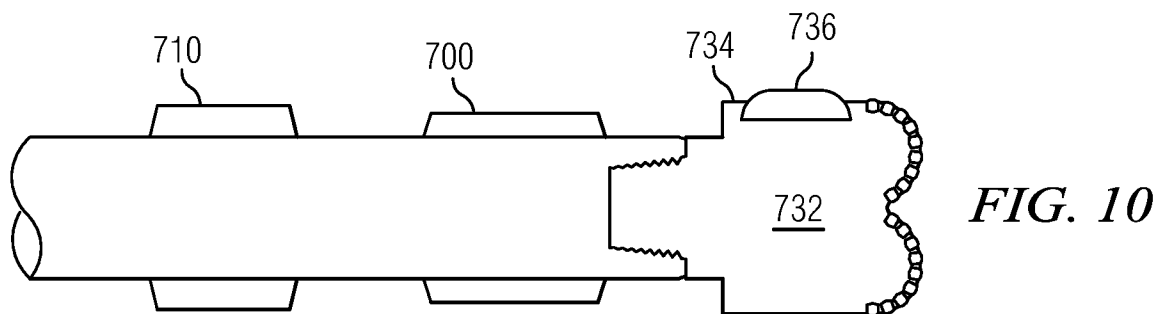
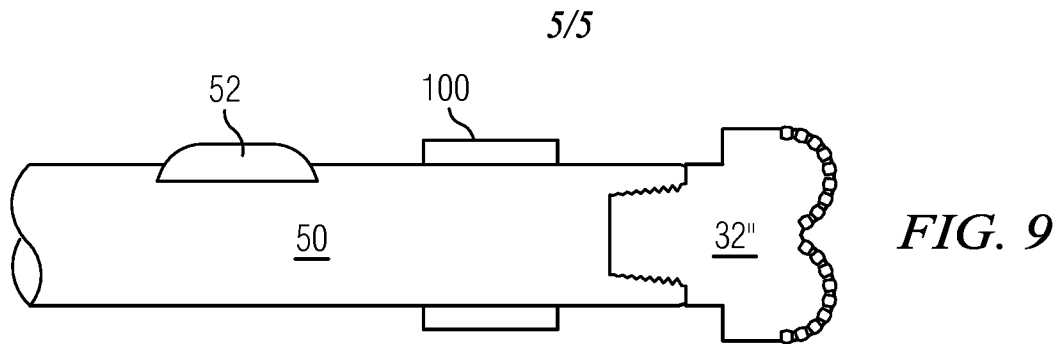


FIG. 5



**FIG. 11**

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2014/036797**A. CLASSIFICATION OF SUBJECT MATTER****E21B 17/00(2006.01)i, E21B 41/00(2006.01)i, E21B 7/20(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 17/00; E21B 7/00; E21B 17/10; E21B 1/00; E21B 10/60; E21B 7/08; E21B 7/20; E21B 44/02; E21B 41/00

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: drill bit, oscillation, sleeve, dogleg and diameter

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2008-0041629 A1 (ARONSTAM et al.) 21 February 2008 See paragraphs [0014], [0055]–[0069] and figures 4–5F.	1–8, 11–14, 16–22
Y		15
A		9, 10, 23
Y	US 2004-0104051 A1 (MORIARTY et al.) 03 June 2004 See paragraph [0051] and figure 3.	15
A		1–14, 16–23
A	US 2010-0236829 A1 (YAO, JING JAMES) 23 September 2010 See paragraphs [0019]–[0037] and figures 3–9.	1–23
A	US 2010-0300761 A1 (EARLES et al.) 02 December 2010 See paragraphs [0050]–[0066] and figures 2, 3.	1–23
A	US 2009-0044980 A1 (SHEPPARD et al.) 19 February 2009 See paragraphs [0067]–[0114] and figures 2A–5.	1–23



Further documents are listed in the continuation of Box C.



See patent family annex.

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Date of the actual completion of the international search

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