



(51) International Patent Classification:

E21B 44/02 (2006.01) *E21B 41/00* (2006.01)
E21B 44/04 (2006.01) *E21B 45/00* (2006.01)
E21B 44/06 (2006.01) *E21B 47/12* (2006.01)
E21B 7/06 (2006.01) *G06F 17/50* (2006.01)

(21) International Application Number:

PCT/US2017/042876

(22) International Filing Date:

19 July 2017 (19.07.2017)

(25) Filing Language:

English

(26) Publication Language:

English

(30) Priority Data:

62/364,833 20 July 2016 (20.07.2016) US
 15/348,003 10 November 2016 (10.11.2016) US

(71) Applicant: **BAKER HUGHES INCORPORATED**
 [US/US]; P.O.Box 4740, Houston, TX 77210-4740 (US).

(72) Inventors: **SPENCER, Reed, W.**; 2943 Smokey Forest Lane, Spring, TX 77386 (US). **UNO, Timothy, P.**; 1219 Matthew Hills Lane, Spring, TX 77386 (US). **HANSON, Jonathan, M.**; 1375 South Roxbury Road, Salt Lake City, UT 84108 (US).

(74) Agent: **MITCHELL, Debra L.** et al.; Traskbritt, P.O. Box 2550, Salt Lake City, UT 84102 (US).

(81) Designated States (unless otherwise indicated, for every kind of national protection available): AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DJ, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID, IL, IN, IR, IS, JO, JP, KE, KG, KH, KN, KP, KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME,

(54) Title: METHODS OF CONTROLLING DRILL BIT TRAJECTORY BY PREDICTING BIT WALK AND WELLBORE SPIRALING

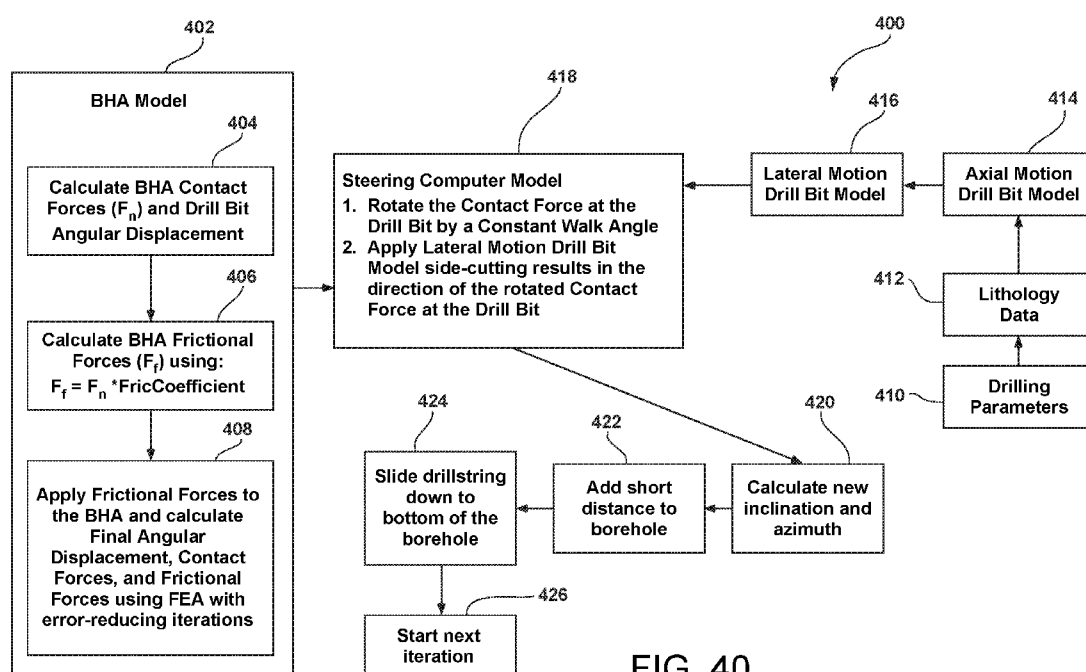


FIG. 40

(57) Abstract: A method of controlling drill bit trajectory in a subterranean formation includes receiving drilling parameters for operating a specific bottomhole assembly (BHA), constructing, with a computer processor, a directional drill-ahead simulator including a computer model of the BHA and the subterranean formation, calculating axial motion and lateral motion of a drill bit connected to a bottom end of the BHA using formation parameters and drilling parameters, predicting bit walk of the drill bit by accounting for and calculating contact forces and frictional forces between the BHA and a wall of a borehole in the subterranean formation using the computer model of the BHA, and determining an adjusted drill bit trajectory to account for the predicted bit walk. The method includes determining adjusted drilling parameters for operating the BHA to substantially follow the adjusted drill bit trajectory and operating the BHA according to the adjusted drilling parameters.

MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ,
OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA,
SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN,
TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

- (84) Designated States** (*unless otherwise indicated, for every kind of regional protection available*): ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Declarations under Rule 4.17:

- *as to applicant's entitlement to apply for and be granted a patent (Rule 4.17(ii))*
- *as to the applicant's entitlement to claim the priority of the earlier application (Rule 4.17(iii))*

Published:

- *with international search report (Art. 21(3))*

- 1 -

**METHODS OF CONTROLLING DRILL BIT TRAJECTORY
BY PREDICTING BIT WALK AND WELLBORE SPIRALING**

5

PRIORITY CLAIM

This application claims the benefit of the filing date of United States Provisional Patent Application Serial No. 62/364,833, filed July 20, 2016, for “METHODS OF CONTROLLING DRILL BIT TRAJECTORY BY PREDICTING BIT WALK AND WELLBORE SPIRALING.” This application also claims benefit of the filing date of U.S. Patent Application Serial No. 15/348,003, filed November 10, 2016, which application is a continuation-in-part application of U.S. Patent Application Serial No. 14/517,433, filed October 17, 2014, titled “DIRECTIONAL DRILL AHEAD SIMULATOR: DIRECTIONAL WELLBORE PREDICTION USING BHA AND BIT MODELS,” which claims the benefit of U.S. Provisional Patent Application Serial No. 61/892,959, filed October 18, 2013, and this application also claims the benefit of U.S. Provisional Patent Application Serial No. 62/364,833, filed July 20, 2016, the disclosure of each of which is incorporated herein in its entirety by this reference.

The subject matter of this application is also related to the subject matter of U.S. Patent Application Serial No. 14/517,445, filed October 17, 2014, titled “AXIAL MOTION DRILL BIT MODEL,” which claims the benefit of U.S. Provisional Patent Application Serial No. 61/892,992, filed October 18, 2013, and the subject matter of this application is also related to the subject matter of U.S. Patent Application Serial No. 14/517,454, filed October 17, 2014, titled “LATERAL MOTION DRILL BIT MODEL,” which claims the benefit of U.S. Provisional Patent Application Serial No. 61/893,011, filed October 18, 2013, the disclosure of each of which is also incorporated in its entirety by this reference.

TECHNICAL FIELD

Embodiments of the present disclosure relate to methods of controlling drill bit trajectory in a subterranean formation to improve drilling operations and plans for drilling by accounting for and predicting bit walk and wellbore spiraling.

BACKGROUND

Geologic formations are used for many applications such as hydrocarbon production, geothermal production, and carbon dioxide sequestration. Typically, boreholes

- 2 -

are drilled into the formations to provide access to them. Drilling rigs disposed at the surface, whether it is land or water, operate drillstrings that are connected to drill bits for drilling the boreholes. In that it is very expensive to operate a drilling rig, efficiencies can be achieved by precisely drilling a borehole to achieve a desired geometry and end
5 location. When boring in an earth formation, a predetermined drill path extending into the earth formation may be provided for an operator to follow. The drill path may curve, turn, or otherwise be nonlinear, requiring the operator to control a direction in which an earth-boring tool proceeds into the earth formation. Components for inclusion in a drillstring, such as a bottomhole assembly (BHA) and one or more earth-boring tools (e.g., an earth-
10 boring drill bit, a reamer, or another tool configured to remove earth material when forming or enlarging a borehole), may be selected for their ability to perform within, and to create, a nonlinear borehole.

The processes of directional drilling are complicated by the complex interaction of forces between the drill bit and the walls of the subterranean formation lining the well
15 borehole. In drilling with rotary drill bits and, particularly with fixed-cutter type rotary drill bits, it is known that if a lateral force (often referred to as a side force or a radial force) is applied to the drill bit, the drill bit may “walk” or “drift” from the straight path that is parallel to the intended longitudinal axis of the well borehole. When a drill bit walks in such a way that the direction angle increases, the drill bit may be said to walk to the right or
20 to exhibit “right walk.” Similarly, when a drill bit walks in such a way that the direction angle decreases, the drill bit may be said to walk to the left or to exhibit “left walk.” When a drill bit does not walk or drift away from the straight path that is parallel to the longitudinal axis of the well borehole at the bottom thereof, the bit may be referred to as an “anti-walk” drill bit and may be said to exhibit “neutral walk.” In a similar manner, when a
25 drill bit drifts in a direction such that the inclination angle increases, the drill bit is said to exhibit a tendency to “build,” and when a drill bit drifts in a direction such that the inclination angle decreases, the drill bit is said to exhibit a tendency to “drop.”

Many factors or variables may at least partially contribute to the reactive forces and torques applied to a drill bit and BHA by the surrounding subterranean formation. Such
30 factors and variables may include, for example, the “weight-on-bit” (WOB), the rotational speed of the bit and BHA, the physical properties and characteristics of the subterranean formation being drilled, the hydrodynamics of the drilling fluid, the length and configuration of the BHA to which the bit is mounted, and various design factors of the drill bit and BHA including the cutting element size, radial placement, back (or forward)

- 3 -

5 rake, side rake, etc. Various complex modeling and computational methods known in the art may be used to calculate the forces and torques acting on a drill bit and BHA under predetermined conditions and parameters. For example, a wellbore design may be created using three-dimensional modeling software by inputting design variables associated with drilling parameters and lithology data and using the computational software to estimate by mathematical calculations the reactive forces and torques applied to the drill bit and BHA by the surrounding subterranean formation during drilling to estimate the trajectory of the drill bit and BHA through the subterranean formation.

10 DISCLOSURE

Disclosed is a method for predicting a path of a borehole that will be drilled in a rock formation by a bottomhole assembly (BHA) comprising a drill bit coupled to a drill tubular, the BHA being operated by a drill rig. The method includes: constructing a BHA model of the BHA, the BHA model having (a) dimensions, geometry, mass distribution, material density, and material stiffness of the BHA and (b) dimensions and geometry of the borehole as predicted to be drilled, the BHA model being configured to calculate (c) one or more points of contact between the BHA and a wall of the borehole and (d) forces imposed on the BHA at the one or more contact points, the forces comprising a side force vector imposed on the drill bit, and (e) drill bit tilt; calculating confined compressive strength of the rock formation using an axial motion drill bit model that receives drilling parameters for the drill rig, drill bit design information, and lithology information comprising formation rock strength; calculating lateral motion of the drill bit using a lateral motion drill bit model that receives (i) the calculated confined compressive strength, (ii) the lithology information, (iii) the drill bit design information, and (iv) the drill bit side force vector and drill bit tilt from the BHA model; calculating a ratio of lateral motion to axial motion using the lateral motion drill bit model; calculating an inclination angle and an azimuthal direction of the BHA using a BHA steering model that receives the ratio; and iterating the above steps by updating the BHA model to include extending the borehole an incremental distance in the direction of the inclination angle and the azimuthal direction and displacing the BHA the incremental distance in the extended borehole; wherein the method is implemented by a processor.

Further disclosed is a non-transitory computer-readable medium having computer-executable instructions for predicting a path of a borehole that will be drilled in an earth formation by a bottomhole assembly (BHA) having a drill bit coupled to a drill

- 4 -

tubular, the BHA being operated by a drill rig, by implementing the following steps. The steps include: constructing a BHA model of the BHA, the BHA model having (a) dimensions, geometry, mass distribution, material density, and material stiffness of the BHA and (b) dimensions and geometry of the borehole as predicted to be drilled, the BHA model being configured to calculate (c) one or more points of contact between the BHA and a wall of the borehole and (d) forces imposed on the BHA at the one or more contact points, the forces comprising a side force vector imposed on the drill bit, and (e) drill bit tilt; calculating confined compressive strength of the rock formation using an axial motion drill bit model that receives drilling parameters for the drill rig, drill bit design information, and lithology information including formation rock strength; calculating lateral motion of the drill bit using a lateral motion drill bit model that receives (i) the calculated confined compressive strength, (ii) the lithology information, (iii) the drill bit design information, and (iv) the drill bit side force vector and drill bit tilt from the BHA model; calculating a ratio of lateral motion to axial motion; calculating an inclination angle and an azimuthal direction of the BHA using a BHA steering model that receives the ratio; and iterating the above steps by updating the BHA model to include extending the borehole an incremental distance in the direction of the inclination angle and azimuthal direction and displacing the BHA the incremental distance in the extended borehole.

In some embodiments, a method of controlling drill bit trajectory in a subterranean formation may include receiving drilling parameters for operating a specific bottomhole assembly (BHA), constructing, with a computer processor, a directional drill-ahead simulator that may include a computer model of the BHA and the subterranean formation, calculating, with the computer processor, axial motion and lateral motion of a drill bit connected to a bottom end of the BHA using at least one formation parameter and at least one drilling parameter, predicting, with the computer processor, bit walk of the drill bit by accounting for and calculating contact forces and frictional forces between the BHA and a wall of a borehole in the subterranean formation using the computer model of the BHA, and determining, with the computer processor, an adjusted drill bit trajectory to account for the predicted bit walk. The method may include determining adjusted drilling parameters for operating the BHA to substantially follow the adjusted drill bit trajectory and operating the BHA according to the adjusted drilling parameters.

In additional embodiments, a method of planning and drilling a wellbore in a subterranean formation may include defining a target in a designated subterranean formation. The method may include predicting wellbore spiraling and bit walk of a drill bit

- 5 -

connected to a specific bottomhole assembly (BHA) that may include using a computer processor programmed to execute a directional drill-ahead simulator that may include a computer model of the BHA and the designated subterranean formation, receiving with the computer processor lithology data and drilling parameters for operating the BHA in the designated subterranean formation, calculating with the computer processor a ratio of lateral motion to axial motion using a lateral motion drill bit computer model and an axial motion drill bit computer model, predicting drill bit trajectory with the computer processor by accounting for and calculating lateral contact forces, angular displacement, and frictional forces using the computer model of the BHA, and adjusting the drill bit trajectory with the computer processor based at least in part on predictions from the computer model of the BHA. The method may include adjusting the drilling parameters for operating the BHA to substantially follow the adjusted drill bit trajectory and drilling the wellbore in the designated subterranean formation based at least in part on the adjusted drill bit trajectory.

In further embodiments, a method of controlling drill bit trajectory in a subterranean formation may include receiving lithology data for a specific subterranean formation, and receiving one or more drilling parameters for operating a bottomhole assembly (BHA), the one or more drilling parameters that may include weight-on-bit, torque, rotary speed, rate of penetration, drilling fluid flow rate, or lateral aggressiveness of a drill bit. The method may include predicting wellbore spiraling and bit walk of a drill bit of the BHA that may include constructing, with a computer processor, a directional drill-ahead simulator that may include a dynamic computer model of the BHA and the subterranean formation, accounting for the wellbore spiraling and the bit walk of the drill bit by rotating a direction of normal contact forces on the drill bit by a constant angle using the computer processor, calculating combined forces on the BHA by adding torsional frictional forces to the normal contact forces in the dynamic computer model of the BHA in each iteration of a finite element analysis using the computer processor, predicting the drill bit trajectory, with the computer processor, based at least in part on calculating the combined forces on the BHA, and adjusting the drill bit trajectory, with the computer processor, based at least in part on predictions for the drill bit trajectory. The method may include adjusting the one or more drilling parameters based at least in part on predictions for the wellbore spiraling and the bit walk of the drill bit.

BRIEF DESCRIPTION OF THE DRAWINGS

The patent or application file contains at least one drawing executed in color. Copies of this patent or patent application publication with color drawings will be provided by the Office upon request and payment of the necessary fee.

While the specification concludes with claims particularly pointing out and
5 distinctly claiming what are regarded as embodiments of the present invention, various features and advantages of disclosed embodiments may be more readily ascertained from the following description when read with reference to the accompanying drawings, in which:

FIG. 1 illustrates a cross-sectional view of an exemplary embodiment of a
10 drillstring and drill bit disposed in a borehole penetrating the earth;

FIG. 2 depicts aspects of output from a bottomhole assembly (BHA) model;

FIG. 3 illustrates inclination measurement convention;

FIG. 4 illustrates a process flowchart for a method for predicting inclination of a borehole being drilled;

15 FIGS. 5A and 5B, collectively known as FIG. 5, illustrates a more detailed process flowchart for the method for predicting inclination of a borehole being drilled;

FIG. 6 depicts aspects of a front steering angle model;

FIG. 7 depicts aspects of the front steering angle model being applied to a BHA;

FIG. 8 depicts aspects of a rear steering angle model being applied to the BHA;

20 FIG. 9 is a flowchart for a method for predicting a path of a borehole that will be drilled in an earth formation by a BHA having a drill bit coupled to a drill tubular where the BHA is operated by a drill rig;

FIG. 10 depicts aspects of a frame of reference of the drill bit;

FIG. 11 depicts aspects of a first cutter cutting formation rock;

25 FIG. 12 depicts aspects of a second cutter cutting the formation rock;

FIG. 13 depicts aspects of a third cutter cutting the formation rock;

FIG. 14 depicts aspects of the formation rock after being cut by three cutters;

FIG. 15 depicts aspects of pickets used as a virtual representation of the drill bit and the formation rock;

30 FIG. 16 depicts aspects of a cutter face and cutter chamfer represented by a picket;

FIG. 17 depicts aspects of rock cut by the cutter face and the cutter chamfer;

FIG. 18 depicts aspects of a projected area of cut rock on a R-Z plane by a series of cutters on one cutter blade on the drill bit;

FIG. 19 depicts aspects of a chamfer cutter coming out of the page with two superimposed pickets;

FIG. 20 depicts aspects of a cutter represented by a picket at a rock interface;

FIG. 21 depicts aspects of three orthogonal forces imposed on a cutter by a local
5 rock surface interfacing with the cutter;

FIG. 22 depicts aspects of circumferential (CIR) and side (SID) forces imposed on a cutter by a local rock surface interfacing with the cutter;

FIG. 23 depicts aspects of a relationship between a cutter and a local rock surface interfacing with the cutter;

10 FIG. 24 depicts aspects of intrinsic specific energy required to cut rock as a function of cutter back rake angle;

FIG. 25 depicts aspects of forces acting on a cutter;

FIGS. 26A through 26C, collectively referred to as FIG. 26, depict aspects of various back rake angle of a cutter;

15 FIG. 27 depicts aspects of force model parameter Ψ as a function of back rake parameter θ for Vosges sandstone;

FIG. 28 depicts aspects of a comparison of predicted versus measured weight-on-bit in a first laboratory drilling simulator test;

20 FIG. 29 depicts aspects of a comparison of predicted versus measured weight-on-bit in a second laboratory drilling simulator test;

FIG. 30 depicts aspects of a comparison of predicted versus measured weight-on-bit in a third laboratory drilling simulator test;

FIG. 31 depicts aspects of a comparison of predicted versus measured rate of penetration at an actual field location;

25 FIG. 32 is a flowchart for a method for predicting an amount of axial motion of a drill bit having one or more cutters for drilling a borehole into a formation rock;

FIG. 33 is a flowchart for depicting aspects of a lateral motion drill bit model;

FIG. 34 depicts aspects of a drill bit having gage pads configured to wear or crush formation rock and gage trimmers configured to cut formation rock;

30 FIG. 35 depicts aspects of a relationship of a gage pad with gage trimmers;

FIG. 36 depicts aspects of a simulation of laterally removing the formation rock with the gage pad and the gage trimmers;

FIG. 37 depicts aspects of lateral displacement as a function of axial displacement for the simulation;

- 8 -

FIG. 38 depicts aspects of a comparison of predictions using the lateral motion drill bit model with measured laboratory side load drilling experiments in Bedford limestone;

FIG. 39 is a flowchart for a method for predicting a change in lateral displacement with a change in axial displacement of a drill bit drilling in a rock formation;

5 FIG. 40 is a process flowchart for a directional drill-ahead simulator;

FIG. 41 is a simplified drawing of a downhole view of the borehole shown in FIG. 1;

FIGS. 42A through 42K are a series of graphs of results of drilling simulations accounting for bit walk while building;

10 FIGS. 43A through 43K are a series of graphs of results of drilling simulations accounting for right-hand bit walk while dropping;

FIG. 44A is a simplified drawing of a top view of a wellbore spiral;

FIG. 44B is a simplified drawing of a side view of a wellbore spiral;

15 FIG. 45 is a simplified transverse cross-sectional view of a BHA in a wellbore, and illustrates force vectors acting on the BHA; and

FIG. 46 is a series of graphs of results of drilling simulations accounting for left-hand bit walk in build direction while turning.

MODE(S) FOR CARRYING OUT THE INVENTION

20 Illustrations presented herein are, in some cases, not meant to be actual views of any particular material, component, or system, but are merely idealized representations that are employed to describe embodiments of the present disclosure. Elements common between figures may retain the same numerical designation.

25 The following description provides specific details, such as processes, acts and structures, in order to provide a thorough description of embodiments of the disclosure. However, a person of ordinary skill in the art will understand that the embodiments of the disclosure may be practiced without employing these specific details. Indeed, the embodiments of the disclosure may be practiced in conjunction with conventional techniques employed in the industry. Only those acts and structures necessary to
30 understand the embodiments of the disclosure are described in detail below. Additional acts or structures for controlling drill bit trajectory in a subterranean formation may be performed by conventional techniques.

Elements of the embodiments have been introduced with either the articles “a” or “an.” The articles are intended to mean that there are one or more of the elements. The

terms “including” and “having” are intended to be inclusive such that there may be additional elements other than the elements listed. The conjunction “or” when used with a list of at least two terms is intended to mean any term or combination of terms. The terms “first,” “second” and the like do not denote a particular order, but are used to distinguish
5 different elements.

The flow diagrams depicted herein are just examples. There may be many variations to these diagrams or the steps (or operations) described therein without departing from the spirit of the invention. For instance, the steps may be performed in a differing order, or steps may be added, deleted or modified. All of these variations are considered a
10 part of the claimed invention.

Disclosed is a drill ahead method for predicting or simulating a geometry of a borehole that will be drilled or is being drilled based on operating parameters that may be applied to a drillstring by a drill rig. In this manner, the operating parameters can be selected so that the actual borehole has a desired geometry such as trajectory or path, bend
15 radius, and final end location. It is known in the art to employ software for simulating the drilling trajectory of the BHA and associated drillstring in directional drilling applications. For example, the computer processing system 12 may be programmed with a software program developed and employed commercially by Baker Hughes Incorporated of Houston, TX is known as the “Directional Drill Ahead Simulator (DDAS).” The DDAS is
20 also disclosed in U.S. Patent App. Pub. No. 2015/0142406, published May 21, 2015, and titled “directional drill ahead simulator: directional wellbore prediction using bha and bit models,” the disclosure of which is incorporated in its entirety by this reference. The drill ahead method uses a drillstring steering model (i.e., steering algorithm) to predict an inclination of the drill bit and thus the borehole at the point it is being drilled. The DDAS
25 may include additional models to predict axial motion and lateral motion and may further include models to predict drilling performance for a specific bit design in a realistic drilling environment. In particular, dynamics of the drill bit are modeled using an axial motion drill bit model, referred to as DRILLBIT, and a lateral motion drill bit model referred to as SIDECUT, which are disclosed in U.S. Patent App. Pub. No. 2015/0142403, published
30 May 21, 2015, and titled “AXIAL MOTION DRILL BIT MODEL,” and in U.S. Patent App. Pub. No. 2015/0142404, published May 21, 2015, and titled “LATERAL MOTION DRILL BIT MODEL,” the disclosure of each of which is also incorporated in its entirety by this reference. Formation lithology for a specific subterranean formation and drill rig operating parameters, such as weight-on-bit, rotary speed, rate of penetration, drilling fluid

- 10 -

flow rate, lateral aggressiveness of the drill bit, or drillstring torque are input into DRILLBIT and/or SIDECUT in order to precisely estimate the motion of the drill bit based on calculated interaction of the drill bit, the BHA and the formation rock. For example, drilling parameters may be received that are specific to the BHA and specific to a defined target in a designated subterranean formation.

Next, apparatus for drilling a borehole is discussed. FIG. 1 illustrates a cross-sectional view of an exemplary embodiment of a drill tubular 5 disposed in a borehole 2 penetrating the earth 3, which may include an earth formation 4. The formation 4 represents any subsurface material of interest that may be drilled by the drill tubular 5. In the embodiment of FIG. 1, the drill tubular 5 is a drillstring made of drill pipes 6 serially coupled together. A drill bit 7 is disposed at a distal end of the drill tubular 5. The drillstring together with the drill bit 7 may be referred to as a bottomhole assembly (BHA). A drill rig 8 is configured to conduct drilling operations such as rotating the drill tubular 5 and thus the drill bit 7 in order to drill the borehole 2. In addition, the drill rig 8 is configured to pump drilling fluid (sometimes referred to as drilling mud) through the drill tubular 5 in order to lubricate the drill bit 7 and flush cuttings from the borehole 2. A mud motor (not shown) may be included in the BHA. The mud motor is configured to convert energy from the drilling fluid into additional rotational energy for rotating the drill bit 7. A steering device 9 is coupled to the drill tubular 5 and is configured to steer the drilling of the borehole 2 in a desired or intended direction using extendable pads 13 for example. Other steering configurations may also be used such as one that bends the BHA. The intended direction may include an inclination direction (i.e., up or down with respect to the earth's surface) and/or an azimuthal direction (i.e., with respect to a reference azimuth such as true or grid north). It can be appreciated that in one or more embodiments the steering device 9 is disposed close to the drill bit 7, within three feet (0.914 meters), for example, so that the force or portion of the force being applied to the drill tubular 5 by the steering device 9 is also being applied to the drill bit 7. The steering device 9 in one or more embodiments may be considered as part of the BHA. In some embodiments, rotary steerable drilling systems (RSS) may be used to steer the BHA through the borehole 2. For example, the RSS may include AutoTrak™ eXact high-build rotary steerable system (RSS) ("AutoTrak™ eXact RSS") commercially available from Baker Hughes Incorporated of Houston, TX. A controller 11 is configured to control the steering device 9 to steer the drilling of the borehole 2 in the desired direction. The controller 11, which may include downhole electronics, may also act as an interface with telemetry to communicate

- 11 -

data or commands between downhole components and a computer processing system 12 disposed at the surface of the earth 3. Non-limiting embodiments of the telemetry include pulsed-mud and wired drill pipe. System operation, control and/or data processing operations may be performed by the controller 11, the computer processing system 12, or a combination thereof. The BHA may include a sensor 10 configured to sense various downhole parameters, which may be transmitted uphole according to programmed instructions to the computer processing system 12 for data recording, processing or display to be utilized by an operator or analyst to control the drilling operations. The computer processing system 12 may be configured to accept inputs (e.g., via the sensors 10 or via a user input device) including simulating drilling operations, to improve aspects of an active drilling operation through corrective measures comprising alteration of operating parameters, to provide recommendations for equipment selection and operation for a subsequent, planned drilling operation, or both. The sensor signals may be provided at selected time intervals, at depth intervals along the drill path, at reduced intervals during drilling of nonlinear portions of the borehole, or a combination thereof.

The controller 11 may receive the signals from the downhole sensors 10 and any other sensors used in the drilling assembly and process the signals according to programmed instructions. The controller 11 may send the results of the processed signals (e.g., current downhole conditions, current position, position relative to the predetermined drill path, current operating parameters, recommended operating parameters, current equipment deployed, and recommended equipment for deployment) to an electronic display of the computer processing system 12, which may be utilized by an operator to control the drilling operations. In some embodiments, measured characteristics of the earth formation 4 may be utilized by the computer processing system 12. In other embodiments, the measured characteristics may be extrapolated using the computer processing system 12 by accessing a database of characteristics of geographically closest earth formations and accepting estimated characteristics of the earth formation 4 (e.g., using linear, polynomial, or other known extrapolation techniques) at the computer processing system 12. Examples of downhole parameters include BHA inclination, BHA acceleration, and formation parameters that may be logged such as mineralogy. The teachings disclosed herein may be implemented in real time by the computer processing system that receives sensor data or the teachings may be implemented by another computer processing system that does not receive sensor data in real time.

- 12 -

In support of the teachings herein, various analysis components may be used, including a digital and/or an analog system. For example, the steering device 9, the downhole sensor 10, the controller 11, or the computer processing system 12 may include digital and/or analog systems. The computer processing system 12 may have components
5 such as a processor, storage media, memory, input, output, communications link (wired, wireless, pulsed mud, optical or other), user interfaces, software programs, signal processors (digital or analog) and other such components (such as resistors, capacitors, inductors and others) to provide for operation and analyses of the apparatus and methods disclosed herein in any of several manners well appreciated in the art. It is considered that
10 these teachings may be, but need not be, implemented in conjunction with a set of non-transitory computer executable instructions stored on a non-transitory computer readable medium, including memory (e.g., read-only memory (ROM), random-access memory (RAM), optical (compact disc read-only memory (CD-ROM)), or magnetic (disks, hard drives)), or any other type that when executed causes a computer to implement the method
15 of the present invention. These instructions may provide for equipment operation, control, data collection and analysis and other functions deemed relevant by a system designer, owner, user or other such personnel, in addition to the functions described in this disclosure. Processed data such as a result of an implemented method may be transmitted as a signal via a processor output interface to a signal receiving device. The signal
20 receiving device may be a display monitor or printer for presenting the result to a user. Alternatively or in addition, the signal receiving device may be memory or a storage medium. It can be appreciated that storing the result in memory or the storage medium will transform the memory or storage medium into a new state (containing the result) from a prior state (not containing the result). Further, an alert signal may be transmitted from the
25 processor to a user interface if the result exceeds a threshold value.

Next, certain definitions are presented for convenience. The process of drilling a subterranean formation is often a three-dimensional process, as the drill bit not only penetrates the formation linearly along a vertical axis, but is either purposefully or unintentionally drilled along a curved path or at an angle relative to a theoretical vertical
30 axis extending into the subterranean formation in a direction substantially parallel to the gravitational field of the earth. As used in this disclosure, the term “drilling operation” means and includes any operation performed during the formation or enlargement of a borehole in a subterranean formation. For example, drilling operations include drilling, reaming, and other formation removal processes.

The term “earth-boring tool,” as used in this disclosure, means and includes any type of tool used for earth removal during the formation or enlargement of a borehole in a subterranean formation and includes, for example, fixed-cutter (i.e., “drag”) bits, roller cone bits, percussion bits, core bits, eccentric bits, bicenter bits, reamers, mills, hybrid bits, and other drilling bits and tools known in the art.

As used in this disclosure, the term “BHA model” relates to a finite element model or beam model that models the dynamics of the BHA (i.e., drillstring and drill bit) in a borehole. In the BHA model, the user can create a hole geometry by specifying the length of a hole section and the inclinations at each end of the hole section. Each section may be represented by a series of circles where each circle represents a cross-section of the borehole. The model automatically represents sections of the BHA between the two ends of the hole section that the user has specified. Once a hole is created, a drillstring or BHA can be created and put in the hole. The finite element model or beam model computes how the drillstring lays in the hole, where it contacts the hole, how the drillstring is curved or flexed and magnitude and direction of the contact forces where it touches the borehole wall based on the operating parameters applied to the BHA by the drill rig. The BHA model can also calculate the bit tilt of the drill bit, which is the angle between the longitudinal axis of the drill bit and the longitudinal axis of the borehole or the difference between the inclination of the drill bit and the inclination of the borehole. One example of a BHA model developed and employed commercially by Baker Hughes Incorporated of Houston, TX is known as the BHASYS PRO. FIG. 2 illustrates an example of output provided by the BHA model, which illustrates the direction and magnitude of the contact forces and the geometry of the BHA. In that BHA models are known to persons skilled in the art, further details of these models are not discussed in further detail.

The essential conventions and coordinate systems used in this disclosure are the definition of inclination, build-up-rate (BUR), and Dog Leg Severity (DLS). Inclination θ is measured from the vertical depth axis as illustrated in FIG. 3. BUR is measured as change in inclination with respect to measured depth. In other words, it is the “hole curvature” projected onto a vertical plane. Dog Leg Severity (DLS) is the change in hole angle with respect to measured depth. It is simply the “curvature of the hole,” regardless of how the hole is oriented. It could be curving to the side, or curving upward, etc.

The inclination will be denoted with the symbol θ . The subscript “new” used with θ_{new} refers to the inclination at the very end (bottom of the hole) of the survey section that is being created by the predictive BUR algorithm. θ_{old} refers to the survey section at the

top of the newly created survey section. It is called “old” because in BHASYS PRO, the inclinations where survey sections join are always equal to one another. Thus, the inclination at the bottom of the hole for survey section N will be equal to the inclination at the top of the survey section for survey section N + 1.

5 Next, a directional drill ahead simulation method 40 for adding a new section of borehole to the BHA model is discussed. Aspects of the method 40 are depicted in FIG. 4. First, the BHA model is run. The BHA model gives its forces, bit tilt, moments, and curvature information to the axial and lateral motion drill bit models. It also gives hole curvature and BHA alignment within the hole to the steering model. Next, the axial motion
10 drill bit model runs using input from formation lithology logs and drill rig operating parameters. It calculates a rock strength (e.g., confined compressive strength) and a rate of penetration (ROP). Then, the ROP and rock strength are given to the lateral motion drill bit model. The lateral motion drill bit model uses this data and the data such as bit side force and bit tilt, which was supplied by the BHA model, to calculate the ratio of lateral ROP to
15 axial ROP or lateral displacement to axial displacement for the drill bit for a certain time period. This is called dL/dZ . A front steering angle, δ_{front} , of the BHA is derived from dL/dZ and is defined as:

$$\delta_{\text{front}} = \tan^{-1} \left(\frac{dL}{dZ} \right).$$

20 Using the small angle approximation, an alternate definition is:

$$\delta_{\text{front}} = \left(\frac{dL}{dZ} \right).$$

The steering model is next invoked (explained in detail below). The steering model calculates inclination and azimuth for the end of a new hole section to be created by
25 simulated drilling using δ_{front} . A new hole section is created based on the calculated inclination and azimuth. The BHA and bit are moved down to the bottom of the new hole section and the three models (BHA, axial motion drill bit model and lateral motion drill bit model) are invoked again. Thus, the cycle continues until the simulation is stopped. The drill ahead simulation method 40 runs the BHA model first, then feeds its results to the
30 axial and lateral drill bit models, which are incorporated into the drill ahead simulation method 40. The drill ahead simulation method 40 then predicts the location and geometry of the next hole section.

There are alternate ways or sequences of running the models, but the main point is that the steering model is fed information by the other models, and a new simulated hole section is placed in the direction that the bit/BHA system wants to drill as calculated by the steering model.

FIGS. 5A and 5B are a flowchart depicting further details of the drill ahead simulation method 40. In an actual drilling scenario, the general directional behavior of the drill bit will be governed or influenced by the following factors: WOB/ROP relationship; lateral bit force/lateral ROP relationship; drill bit tilt, drill rotary speed (e.g., RPM); confined compressive strength (CCS) of the formation rock; drilling fluid flow rate (if excessive in weak lithology); and dynamic stability of the borehole as it is being drilled. Hence, these and other factors are included in the models that feed information to the steering model.

Next, the drillstring steering model is discussed. The drillstring steering model includes a front steering angle model. Steering accuracy may be improved by adding a rear steering angle model to the front steering angle model. The front steering angle model is based on the kinematic motion of a two-wheeled vehicle, such as a bicycle. FIG. 6 illustrates a simple diagram of such a vehicle in a top view and aspects related to a front steering angle.

The following equation describes the angular rate of change with respect to time of the vehicle as a function of the velocity V of the vehicle, the length L of the wheel base, and a front steering angle δ .

$$\dot{\theta} = \frac{V}{L} \tan(\delta(t))$$

The steering angle is the angle between the vehicle's longitudinal axis and the direction that the front wheel is pointing. The front steering angle model makes an analogy between this two-wheeled vehicle and the portion of the BHA from the bit to the first point of contact with the borehole wall. One difference between a bicycle path and directional drilling is that the back wheel of a turning bicycle does not follow the front wheel's path. In directional drilling, the second point of contact of the BHA does follow the path of the bit, which makes the first point of contact with the formation. For simplicity, this difference is neglected at this point.

FIG. 7 depicts aspects of the front steering angle as applied to the BHA. The following parameters are used to describe the BHA drilling the borehole:

$\dot{\theta}$: The time rate of change of the orientation angle of the frame of the vehicle = $\frac{d\theta}{dt}$;

V : The velocity of the vehicle = ROP = $\frac{ds}{dt}$;

5 s : The measured depth;

ds : The change in measured depth; and

δ : The steering angle of the bit. (Note that this is not bit tilt. No physical part on the bit has necessarily been tilted. The steering angle δ can be conceptually thought of as the angle between: the axis of the tool (from bit to first point of contact after the bit) and the instantaneous trajectory of the bit.)

10

As discussed above, the steering angle of the BHA is influenced by certain drilling and lithology parameters. All of these parameters do change in time during a normal drilling run. For now $\delta(t)$ will be denoted as δ , with the assumption that it can change throughout the run as time or depth change because the parameters mentioned above will change with time or depth. Using L to denote the distance from the drill bit to the first point of contact of the BHA after the drill bit, the equation immediately above for $\dot{\theta}$ may be rewritten as:

15

$$\frac{d\theta}{dt} = \frac{ds}{dt} \left(\frac{\tan \delta}{L} \right)$$

20

The dt terms in the denominator can be canceled, leading to the following equation:

$$d\theta = ds \left(\frac{\tan \delta}{L} \right)$$

This equation can be rewritten as:

$$\frac{d\theta}{ds} = \left(\frac{\tan \delta}{L} \right)$$

25

where $d\theta/ds$ is the change in bit axis inclination (and hole inclination) with respect to depth.

The curvature of a circular section (i.e., borehole cross-section) is mathematically defined as:

$$\frac{d\theta}{ds} = \left(\frac{1}{R}\right) = k$$

- 5 where R is the radius of the circular survey section and k is the curvature of the circular survey section (i.e., radius of curvature of the borehole at the survey section). Hence, the instantaneous curvature (or curvature for one iteration) may be mathematically described as:

$$k = \frac{d\theta}{ds} = \left(\frac{\tan \delta}{L}\right)$$

- 10 This equation can be rewritten to provide the change in inclination angle per change in depth as:

$$\frac{\Delta\theta}{\Delta s} = \left(\frac{\tan \delta}{L}\right)$$

- This equation can be manipulated to find the new inclination angle θ_{new} for the new survey section that the drill ahead simulation method predicts in an iteration. θ_{old} is the inclination at the hole bottom prior to the creation of the new survey. Δs is the distance that the borehole is drilled ahead by simulation during each iteration in the drill ahead simulation method. θ_{new} may then be written using the front angle steering model as:

$$\theta_{new} = (\Delta s) \left(\frac{\tan \delta}{L}\right) + \theta_{old}$$

20

- As mentioned above, the steering model may be improved by combining the rear angle steering model to the front steering angle model. FIG. 8 depicts aspects of the rear steering angle model. In FIG. 8, the BHA has an imaginary steering front wheel and an imaginary steering rear wheel. The rear wheel must follow the path of the borehole already drilled as if the rear wheel was guiding the BHA at the steering axis of the rear wheel. The rear steering angle model is very similar to the front steering angle model. The only two differences are that now a rear steering angle appears in the formula immediately above, and the cosine of the front steering angle modifies the prediction as well in the following equation:
- 25

$$\theta_{new} = \theta_{old} + \Delta s(\cos(\delta_{front})) \frac{[\tan \delta_{front} - \tan \delta_{rear}]}{L}.$$

The rear steering angle δ_{rear} is the angle between the borehole inclination θ at the first point of contact of the BHA after the drill bit contact and the tool axis, or it can be defined as the angle
 5 between the borehole inclination θ at the first point of contact after the drill bit and the borehole inclination θ where the bit contacts the wall. Using the latter definition, the rear steering angle may be written as:

$$\delta_{rear} = \theta_{(first\ contact\ point\ after\ drill\ bit)} - \theta_{(contact\ point\ at\ drill\ bit)}.$$

10 FIG. 9 is a flowchart for one example of a method 90 for predicting a path of a borehole that will be drilled in an earth formation by a bottomhole assembly (BHA) having a drill bit coupled to a drill tubular, the BHA being operated by a drill rig. Block 91 calls for constructing a BHA model of the BHA. The BHA model includes (a) dimensions, geometry, mass distribution, material density, and material stiffness of the BHA and (b) dimensions and
 15 geometry of the borehole as predicted to be drilled. The BHA model is configured to calculate (c) one or more points of contact between the BHA and a wall of the borehole and (d) forces imposed on the BHA at the one or more contact points, the forces comprising a side force vector imposed on the drill bit, and (e) drill bit tilt. Block 92 calls for calculating confined compressive strength of the rock formation using an axial motion drill bit model that receives
 20 drilling parameters for the drill rig, drill bit design information, and lithology information comprising formation rock strength. Block 93 calls for calculating lateral motion of the drill bit using a lateral motion drill bit model that receives (i) the axial ROP from the axial motion drill bit model, (ii) the lithology information, and (iii) the drill bit design information, and (iv) the drill bit side force vector and drill bit tilt from the BHA model. Block 94 calls for
 25 calculating a ratio of lateral motion to axial motion. Block 95 calls for calculating an inclination angle and an azimuthal direction of the BHA using a BHA steering model that receives the ratio. The inclination angle together with the azimuthal direction (e.g., direction or angle with respect to true north) provides a three-dimensional direction. Block 96 calls for iterating the above steps by updating the BHA model to include extending the borehole an
 30 incremental distance in the direction of the inclination angle and the azimuthal direction and displacing the BHA the incremental distance in the extended borehole.

Each of the blocks in the method 90 may be implemented by a processor such as in a computer processing system. In addition, data used by the method 90 as input to the

various above discussed models may be updated in real time as an actual borehole is being drilled according to drilling parameters that were used to obtain the predicted borehole path. The updated data may be obtained from one or more sensors disposed on a BHA that drills the actual borehole. In this manner, the accuracy of the predicted path can be improved by using the updated data. Sensors may include a borehole caliper sensor and/or a formation sensor that is configured to sense data from which the formation lithology may be derived. Examples of formation sensors include a natural gamma-ray sensor and neutron tools that emit neutrons and sense neutrons or gamma-rays resulting from neutron interactions with the formation.

Next, the axial motion drill bit model (i.e., DRILLBIT) is discussed. The axial bit model is part of the Directional Drill-Ahead Simulator. It allows for predicting drilling performance for a specific bit design in a realistic drilling environment and, in particular, uses a PDC cutter force model to calculate the forces on the drill bit. Given operating parameters, formation characteristics and a specific bit design, the axial model predicts the rate of penetration (ROP) if the weight-on-bit (WOB) is prescribed or predicts the WOB if ROP is prescribed. The overall approach is as follows: (a) from bit design and operating parameters, compute the areas of cut (projected onto a vertical plane) across the face and chamfer for each of the cutters representing the bit; (b) from details of the rock formation, drilling depth and mud weight, estimate the confined compressive strength of the rock formation; (c) given these estimated areas of cut, the detailed geometry of how the edge of the cutter is engaging with the rock and the CCS of the rock formation, calculate forces on the face and chamfer of the cutters using a "force model" (discussed below); (d) and sum the forces on all of the cutters to find the net force on the drill bit. If ROP is prescribed, these forces are easily translated to a WOB (weight-on-bit) and TOB (torque-on-bit). If WOB is prescribed, an iterative procedure is used by which ROP is adjusted until the predicted WOB matches the prescribed WOB.

If the Directional Drill-Ahead Simulator (DDAS) is drilling with a prescribed ROP, then the only thing passed back from the axial motion drill bit model that the DDAS uses is the CCS and some information on the bit design. However, if the DDAS is drilling with a prescribed WOB, the CCS, ROP and information on the bit design are passed back and used by the DDAS. Specifically, SIDECUT (the lateral motion drill bit model) needs a value of CCS and information on the bit design in order to predict the lateral migration of a bit that has an applied side load.

The axial motion drill bit model assumes that the bit is drilling “on-center” and the bit axis of revolution is always coincident with a fixed Z axis in the rock frame of reference as illustrated in FIG. 10. The axial model calculates the areas of cut and forces as each cutter passes through the vertical plane defined as $[Y=0, X>0]$. In this frame of reference, the Z axis lies on the bit axis of rotation and positive Z is in the direction of nose to shank. The rock surface is defined in this plane as a simply-connected line defined in this vertical plane. FIG. 10 illustrates this frame of reference with the vertical plane superimposed. The drill bit in FIG. 10 is a polycrystalline diamond compact (PDC) bit.

As part of the axial model discussion, drill bit rotation and rock surface update are now discussed. In one or more embodiments, the drill bit and rock surface are modeled using nodes and the node locations are updated based on the drill bit-rock interaction. The cutters on the bit are first sorted in terms of increasing angle around (angular position on the bit). Consider a bit with 3 cutters and parameters listed Table 1.

TABLE 1

Cutter:	Angle around (degrees)	Radial position (in)
1	0	2.5
2	45	1.5
3	270	2.0

The rock surface is updated during one revolution of this bit as follows: (1) the intersection of cutter 1 with the rock is calculated and the rock surface is updated accordingly; (2) the bit is rotated through an angle $(45-0)$ and, based on RPM and ROP, the bit vertical position is modified accordingly; (3) the intersection of cutter 2 with the rock is calculated and the rock surface is updated accordingly; (4) the bit is rotated through an angle $(270-45)$ and, based on RPM and ROP, the bit vertical position is modified accordingly; (5) the intersection of cutter 3 with the rock is calculated and the rock surface is updated accordingly; and (6) the bit is rotated through an angle $(360-270)$ and, based on RPM and ROP, the bit vertical position is modified accordingly. This sequence is repeated until run termination criteria (e.g., a number of iterations) are met. FIGS. 11 through 14 illustrate the progression of the rock surface update.

The axial model is computationally fast because in one or more embodiments it is required only to keep track of the rock surface on one 2D plane and calculate cutter interaction with the rock surface on this plane. This is possible for the situation where the

bit is drilling on-center. As a cutter passes the X-Z plane, it clips off the tops of the pickets in order to update the represented rock surface as illustrated in FIG. 15.

Further, as part of the axial model discussion, the calculation of the areas of cut is now discussed. In one revolution of the drill bit, the bit moves downward by the amount
 5 $DZ = ROP / (5 \times RPM)$ for a given ROP and RPM. ROP is in ft/hr and DZ is in inches in this equation. If the cutters are sorted in increasing angle around (see previous discussion), the amount of vertical motion DZ' associated between one cutter passing through a vertical plane and next cutter passing through that same vertical plane is simply DZ prorated by the difference DAA in those angle around values as in the following equation.

10
$$DZ' = DZ \times DAA / 360$$

So as each cutter (sorted in increasing angle around) passes through a vertical plane, all of the cutters are moved downward with respect to the rock pickets by the amount DZ' . Comparison of the overlap between the cutters and the rock surface allows for calculating the area of cut of
 15 the cutter, which is then used in the cutter force model.

The PDC cutters' edges and chamfers are represented initially as ellipses (circles with non-zero back rake projected onto a vertical plane) as they pass through the rock "plane." These are exact (analytic) representations for an unworn cutter with the design back rake and side rake. The ellipses are broken into vertical pickets of user-prescribed width (e.g., default
 20 width = 0.003"). The rock surface is also broken up into an identical set of pickets that match the location (along the X-axis) of the cutter pickets as illustrate in FIG. 15. FIG. 16 illustrates this configuration. FIG. 16 shows the cutter face (with chamfer) with a non-zero back rake coming out of the page at the viewer. If the cutter is allowed to wear, that edge of the cutter in contact with the rock will deviate from an ideal ellipse. This deviation, applied on a
 25 picket-by-picket basis, is governed by a wear model discussed in the disclosure further below. The areas of cut are delineated in FIG. 16. The upper patch is the (projected) area of cut on the cutter face and the lower patch is the (projected) area of cut on the chamfer. It is noted that these areas are dependent upon the location of the rock surface with respect to the cutter at a particular picket. The rock surface may only intersect part of a chamfer and none of the face at
 30 a picket location. The areas of cut on the chamfers and face are kept track of independently as each will behave differently regarding cutter forces. This is also discussed later. It is also possible for a cutter picket to be completely worn through and no longer exist.

It is noted that vertical pickets are used because it is a natural choice when predicting cutter wear. One cutter picket is associated uniquely with one rock picket. With

this choice, there may be some error introduced at the flanks of the cutter. The force model discussed below has extensive bookkeeping to account for pickets that intersect only the chamfers and pickets that intersect both the chamfers and face of the cutter.

Further, as part of the axial model discussion, the updated rock surfaced is now
5 discussed. The new rock surface (after a cut) is generated by clipping the rock pickets at the bottom-most position of the cutter pickets. This is illustrated by the dashed lines in the FIG. 17. FIG. 17 shows the updated rock surface for a new cutter. If the cutter is worn, the updated rock surface will simply be the bottom-most end of a picket when the picket takes a cut. If the picket does not take a cut, the rock surface at that location does not change.

10 Further, as part of the axial model discussion, the cutter interaction is now discussed. There is generally overlap in the radial extent of adjacent (in the radial coordinate) cutters. The shape and magnitude of the area of cut depends upon the radial overlap of these cutters and their respective angles around. FIG. 18 illustrates an example. This example represents the areas of cut for all cutters on a single blade of a PDC bit.
15 Areas of cut on a cutter, and the forces associated with these areas of cut, depend both on the cutter layout on the bit and operating parameters (e.g., RPM, ROP). After a few revolutions of the bit, the magnitude and shape of the areas of cut stabilize to constant values for a fixed ROP and RPM. Note that the image in FIG. 18 is a general “bit profile” image generated by the axial model. The cutters and respective areas of cut have, for the
20 purpose of plotting only, been rotated back to the X-Z plane with the helix angle taken into consideration. The reason for this is two-fold: (1) so that the image will conform to a typical engineering “side view” of the bit and (2) that the geometry of the area of cut is plotted within its associated cutter.

Further, as part of the axial model discussion, the effective back rake of a cutter is
25 now discussed. The effective back rake is an angle that plays a role in cutting forces. Effective back rake is not the design back rake found in a bit design file. The two are associated but that is all. Effective back rake is the angle between the (normal to the) local cutting surface and the local rock surface. FIG. 19 illustrates a chamfer cutter coming out of the page. Two pickets are superimposed on the image. The two large arrows represent
30 the surface normals of the cutter chamfer at the locations of the pickets. The small arrow is the surface normal at the cutter face at the location of one of the pickets. The dots represent vectors coming out of the page and are parallel with the local rock surface that the cutter will see as it passes through the rock. The effective back rake (EBR) is that angle between this vector and the arrows. As is evident, the EBR can depend upon location on the cutter,

... both along the edge of the cutter and whether or not the cut is on the chamfer or on the face.

FIG. 20 is a close-up of a bottom of a picket edge (at an edge of a cutter). The edge of the cutter is delineated by the contact between the picket and the triangle. The vector
 5 arrow into the cutter is the normal to the local cutter surface (either on a chamfer or on the face). Note that this normal vector is in three dimensions and has three components, each associated with an axis in a right-handed coordinate system. There is a component of the normal vector coming out of the page. The angle ϕ is referred to as the “cut” angle.

A simple two-dimensional (2D) rotation operator is constructed that will rotate the
 10 bottom edge of the picket into the horizontal plane. This operator is applied to the three-dimensional (3D) normal to the local cutter surface (red vector depicted in FIG. 20). If the resulting rotated normal vector (normalized) has components (N_x , N_y , N_z), where X and Z have been defined previously Frame”) and Y is “out of the screen, then the effective back rake (EBR) and effective side rake (ESR) are given by:

$$15 \quad EBR = \tan^{-1} \left[\frac{N_z}{N_y} \right] \quad \text{and}$$

$$ESR = \sin^{-1}(N_x).$$

These expressions for EBR and ESR are computed on a picket-by-picket basis for all of the
 20 pickets intersecting a cutter.

Further, as part of the axial model discussion, the forces on cutters are now discussed. The forces on a cutter are computed by summing the forces on individual pickets that span the cutter. Forces on an individual picket will depend upon the area of cut on the chamfer, the area of cut on the face, the effective back rake, the rock formation, confined compressive strength
 25 (CCS), drilling depth and mud weight. Details of the force model are given in a different section. Once the normal (F_n) and circumferential (F_t) forces are computed on a picket, they are transformed back into the bit frame of reference. The net force on the bit is a summation of the individual cutter forces which are themselves the summations of individual picket forces. Consider FIG. 21 illustrating the local (picket) rock surface with the normal (F_n), tangential
 30 (F_t), and radial (F_r) forces generated by the force model. The force model is applied on a picket-by-picket basis. F_n is always normal to the local rock surface (regardless of the

- 24 -

orientation of the local rock surface with respect to the earth). F_t is in the direction normal to the X-Z plane and F_r is perpendicular to the plane containing F_n and F_t .

With this nomenclature, the following force components can be defined.

Components of F_N in XYZ frame

$$\begin{aligned} 5 \quad F_{NZ} &= F_N \cos(\varphi) \\ F_{NY} &= 0 \\ F_{NX} &= F_N \sin(\varphi) \end{aligned}$$

Components of F_R in XYZ frame

$$\begin{aligned} 10 \quad F_{RZ} &= F_R \sin(\varphi) \\ F_{RY} &= 0 \\ F_{RX} &= -F_R \cos(\varphi) \end{aligned}$$

Components of F_t in XYZ frame

$$\begin{aligned} 15 \quad F_{TZ} &= 0 \\ F_{TY} &= F_T \\ F_{TX} &= 0 \end{aligned}$$

At this point, one could simply add all the Z components to get the weight on cutter, all the Y components to get the circumferential force and all of the X components to get the radial force. This however does not take into consideration the helix angle. Keep in mind that the force model is in the frame of reference of the local rock surface. Therefore, a correction for helix angle α must be made. The final equations for the forces on a particular picket are given by the following equations.

$$\begin{aligned} \text{WGT (vertical force)} &= (F_{NZ} + F_{RZ}) \cos(\alpha) + F_{TY} \sin(\alpha) \\ \text{SID (side force)} &= F_{NX} + F_{RX} \\ \text{CIR (circumferential force)} &= -(F_{NZ} + F_{RZ}) \sin(\alpha) + F_{TY} \cos(\alpha) \\ \text{TRQ (torque on picket)} &= R_{pic} \text{ CIR (see below for definition of } R_{pic}) \end{aligned}$$

It is noted that the helix angle is computed for each picket and is given by the following equation:

$$\alpha = \tan^{-1} \left[\frac{ROP}{10 \pi R_{pic} RPM} \right]$$

- 25 -

where ROP is penetration rate (ft/hr), RPM is bit rotary speed, and R_{pic} is radial position of picket (distance from bit axis to picket in horizontal plane).

These force components on a picket are illustrated graphically in FIG. 22. In FIG. 22, AA is the angle around of the cutter and CIR and SID are defined as above. Note that the view is from a perspective looking down onto the horizontal plane from shank to nose. In the XYZ frame of reference, and referring to FIG. 22, the forces on a picket are given by the following equations.

$$\begin{aligned} dF_x &= CIR \sin(AA) + SID \cos(AA) \\ dF_y &= SID \sin(AA) - CIR \cos(AA) \\ dF_z &= WGT \end{aligned}$$

The total force on a cutter is simply a summation of these forces for all (N) pickets associated with that cutter, as given by:

$$\begin{aligned} F_x &= \sum_N dF_x \\ F_y &= \sum_N dF_y \\ F_z &= \sum_N dF_z \end{aligned}$$

15

where N is the number of pickets associated with a particular cutter. The net force and moment on the bit is thus a summation of forces and moments on all of the cutters on the bit.

Next, the cutter force model is discussed. The forces on a PDC cutter are given by two orthogonal components: a “tangential” component that is parallel with the local rock surface and a “normal” component that is perpendicular to the local rock surface. Note that when evaluating such things as weight-on-bit and torque-on-bit, F_n and F_t must be transformed to the bit frame of reference. The model is defined by the following equations:

$$\begin{aligned} F_t &= \varepsilon A \\ F_n &= \zeta F_n \end{aligned}$$

20

where:

F_t = cutting force parallel with local rock surface;

F_n = cutting force perpendicular to local rock surface;

ε = "intrinsic specific energy";

A = projected area of cut; and

ζ = ratio of F_n to F_t (dependencies to be defined).

FIGS. 23 and 18 define the PDC cutter in relationship to the rock. FIG. 23 is a side
 5 view of a cutter moving through the rock, with F_n and F_t indicated. FIG. 18 shows one
 blade of a PDC bit with the cutters coming out of the page. FIG. 18 illustrates what is
 meant (in the following) by the projected areas of cut (blackened areas) associated with the
 rock removed.

The cutter force model is extended to a practical form by identifying the nature of
 10 "intrinsic specific energy" and developing a means of characterizing its value, on a
 site-specific basis, from well logs, drilling depth and mud weight.

Next, the intrinsic specific energy ε aspects of the cutter force model are discussed.
 The "intrinsic specific energy" term ε is the effective cutting strength (or resistance to be cut)
 of the rock. This effective strength will depend upon the following: wellbore pressure; hole
 15 depth; mud weight; lithology; cutter orientation on the bit; cutter geometry (face/chamfer);
 and cutter interfacial friction coefficient. The cutter orientation on the bit and the orientation
 of the formation rock with respect to the bit provide an orientation of the cutter with respect to
 the formation rock to be cut, which is accounted for in the intrinsic specific energy as
 disclosed herein. It is assumed that the "intrinsic specific energy" is equivalent to the confined
 20 compressive strength of the rock with the modification that this confinement also includes
 confinement due to the cutter, mud column, and pore pressure effects. The confined
 compressive strength (CCS) is taken to be the unconfined compressive strength (UCS)
 modified by a term associated with the confining pressure and is defined as follows:

$$CCS = UCS + \frac{1 + \sin(FA)}{1 - \sin(FA)} CP$$

25

where CCS is confined compressive strength (computed); UCS is unconfined compressive
 strength (from well log); FA is internal angle of friction (from well log); and CP is confining
 pressure (computed from well log, mud weight and drilling depth). Note that the confined

compressive strength (CCS) equals the unconfined compressive strength (UCS) when there is no confining pressure (CP=0). The confining pressure CP in the expression will depend upon hole depth, mud weight and lithology and is discussed further below.

The intrinsic specific energy cannot be equated to the CCS because ε can be backed out as a function of cutter back rake θ as illustrated in FIG. 24 for Vosges sandstone under atmospheric conditions. From FIG. 24, it is clear that the strength of the rock increases with increasing cutter back rake. This is associated with the additional confinement of the rock by the cutter. The intrinsic specific energy ε is close to the uniaxial compressive strength of Vosges sandstone at $\theta = 0$. We therefore conclude that the intrinsic specific energy can be represented, to first approximation, by the algebraic form: $\varepsilon = \gamma(\theta) CCS$ where a reasonable functional form (see FIG. 24) for γ is taken as: $\gamma(\theta) = 1 + A_2 \tan(\theta)$. A_2 is a multiplicative parameter included in order to allow adjustment during model fitting to lab or field data.

Next, the cutter force inclination aspects of the cutter force model are discussed. The ratio of F_n to F_t is also not a simple matter. FIG. 25 illustrates the forces acting on a cutter. The cutter back rake is given by θ and ψ is the inclination due to friction of the net cutting force from the perpendicular to the cutting face. From FIG. 25, the ratio may be expressed as:

$$\frac{F_n}{F_t} = \tan(\theta + \psi)$$

where the inclination of the net cutter force with respect to the rock surface is given by $\alpha = \theta + \psi$. Therefore the following association may be made:

$$\zeta(\theta, \psi) = \tan(\theta + \psi) .$$

The effective back rake θ is a well-defined parameter. ψ on the other hand is not so straight-forward. Depending upon the degree of back rake, the rock can “flow” upward along the cutter face or downward beneath the cutter as illustrated in FIGS. 26A through 26C. Based on laboratory experiments on Vosges sandstone, the relationship of ψ with back rake θ is illustrated in FIG. 27.

Noting that the data is more or less symmetrical about $\theta=45$ degrees in FIG. 27, the following form for ψ may be inferred:

$$\psi = \tan^{-1}[C\mu(90 - 2\theta)/90]$$

where θ is in degrees and $C\mu$ is a constant that can be related to the interfacial friction coefficient between the cutter and the rock. It is noted that $C\mu$ can be considered a free parameter and can be determined by fitting laboratory drilling data to the model and thus it is not required that it be related to some physical mechanism. Note that in the discussion that follows, the force model coefficient $A_3 = C\mu$.

Next, the confining pressure aspects of the cutter force model are discussed. The confining pressure (CP) model is one of the key elements of a successful “drill ahead” simulation. The confining pressure model used in DRILLBIT differentiates between permeable and impermeable formations based on a lithology log according to the following.

$$\begin{aligned}\Sigma_{\text{imper}} &= \% \text{Shale} + \% \text{Coal} + \% \text{Polyhalite} + \% \text{Sand-shale mix} + \% \text{Anhydrite} \\ \Sigma_{\text{perm}} &= \% \text{Sandstone}\end{aligned}$$

The percents are the fractions of the indicated rock types and, at every depth, the sum of these fractions is unity. If the formation is deemed impermeable, the CP at that depth is simply the bottom hole pressure (BHP) that is calculated from the hole depth and the mud weight according to: $CP \text{ (psi)} = BHP = 0.052 \times \text{depth (ft)} \times \text{mud weight (ppg)}$. If the formation is deemed permeable, the confining pressure is the above minus the pore pressure: $CP \text{ (psi)} = \Delta P$ where $\Delta P = 0.052 \times \text{depth (ft)} \times [\text{mud weight (ppg)} - P_p]$ and $P_p = \max [8.5, \text{mud weight (ppg)} - 0.5]$. The effective porosity of the formation and the confining pressure CP (used in the confined compressive strength calculation) is calculated according to the following:

$$\begin{aligned}\Phi_{\text{eff}} &+ [1 - \Sigma_{\text{imper}}] \phi \\ CP &= \Delta P, \Phi_{\text{eff}} > 0.2 \\ CP &= BHP, \Phi_{\text{eff}} < 0.05 \\ CP &= \Delta P [(\Phi_{\text{eff}} - 0.05)/0.15] + BHP [(0.2 - \Phi_{\text{eff}})/0.15].\end{aligned}$$

ϕ is the measured porosity of the formation or porosity inferred from well log data. Note that the last entry above is an interpolation between the maximum allowed CP (namely BHP) and the minimum allowed CP (namely ΔP) and that this interpolation is based on effective porosity.

Next, the mud weight correction factor aspects of the cutter force model are discussed. A mud weight correction factor is implemented in DRILLBIT. The correct interpretation of this effect is via the “chip hold-down effect” that has to do with the dislodgement of a chip created in the cutting process. If fluid cannot migrate between the produced chip and the

formation from whence it came, the chip is subject to the entire load of the fluid column and the formation is tougher to drill. However, if fluid can migrate into the fractures and equilibrate the stresses on the chip, the chip can be removed easily. Since a fluid migrates through generated cracks in this mechanism, the migration will depend upon mud viscosity (related to mud weight) and will be independent of whether the formation is initially permeable or impermeable. The mud correction factor is:

$$\eta = 2.998 - 0.8876 \log(\text{mud weight})$$

where the mud weight is given in pounds per gallon (ppg).

Next, aspects of implementing the cutter force model are discussed. The force model is applied independently to the cutter chamfer and the cutter face. Depending upon the operating parameters all or part or none of the chamfer pickets and face pickets will be engaging the rock. The associated “bookkeeping” for this is an integral part of the axial bit model. Many well logs do not give a specific lithology (sandstone, limestone, etc.) at a particular depth but rather a mix of lithologies in terms of fractional content. In general, the sum of the fractions at a given depth is unity. The axial model accommodates this by: (i) assigning (through lab or field calibration on specific lithologies) values to the force model coefficients A1, A2, A3 and (ii) weighting these force model coefficients at a specific depth according to the fraction of the associated lithology. For example, if at some depth, the log indicates 25% shale and 75% limestone. Then, at this depth: $A1 = 0.25 \times A1_{\text{shale}} + 0.75 \times A1_{\text{limestone}}$; $A2 = 0.25 \times A2_{\text{shale}} + 0.75 \times A2_{\text{limestone}}$; and $A3 = 0.25 \times A3_{\text{shale}} + 0.75 \times A3_{\text{limestone}}$.

Next, examples are presented using DRILLBIT. FIGS. 28 through 30 represent a comparison of predicted and measured weight on a few laboratory drilling simulator tests. During each drilling test, the prescribed WOB was changed and the measured ROP was recorded. The upper and lower bounds in these plots were computed by propagating uncertainties in porosity, friction angle and UCS through DRILLBIT. In FIG. 28, the drilling fluid was water and the rock was Carthage limestone. In FIG. 29, the drilling fluid was 11 lb. (4.990 Kg) water-based drilling mud and the rock was Carthage limestone. In FIG. 30, the drilling fluid was 16 lb. (7.257 Kg) oil-based drilling mud and the rock was Mancos shale. Another example is a comparison of predicted with measured ROP at an actual field location as illustrated in FIG. 31. The lithology log from this site along with the actual drill bit design used in the field, and actual WOB applied to the bit was used to predict the ROP. The legend

for this plot is: SHA: fraction of shale; SSA: fraction of sandstone; LSO: fraction of limestone; DOL: fraction of dolomite; POR: formation porosity; CP: predicted confining pressure; and UCS: unconfined compressive strength.

FIG. 32 is a flowchart for a method 320 for predicting an amount of axial motion of a drill bit having one or more cutters for drilling a borehole into a formation rock. Block 321 calls for receiving lithology data for the formation rock. Block 322 calls for receiving drilling parameters that include mud weight and depth of drill bit for a drill rig that will operate a drill tubular coupled to the drill bit and drill bit design information. Block 323 calls for calculating confined compressive strength of the formation rock using the received lithology data, drilling parameters, and drill bit design information. Block 324 calls for calculating an area of cut into the formation rock by each of the one or more cutters. Block 325 calls for calculating an effective back rake of each of the one or more cutters. Block 326 calls for calculating a force applied to each of the one or more cutters using the calculated confined compressive strength of the formation rock, the area of cut and the effective back rake of the one or more cutters, and by accounting for an orientation of each of the one or more cutters with respect to a surface of the rock to be cut. Block 327 calls for summing the calculated forces applied to each of the one or more cutters to calculate the WOB and TOB (torque-on-bit). The above method may be implemented by a processor. If ROP is prescribed, then the method 320 may be used to calculate the WOB and TOB that provides the prescribed ROP. Alternatively, if WOB is prescribed, then the ROP and TOB may be calculated to provide the prescribed ROP. If WOB is prescribed, then values of ROP and TOB may be varied to calculate the resulting WOB and comparing this value to the prescribed WOB until an acceptable difference or zero difference is achieved. The method 320 may call for representing the drill bit with a first set of virtual pickets and the formation rock with a second set of virtual pickets. In one or more embodiments, the first set of pickets lines up with the second set of virtual pickets at the interface of the drill bit with the formation rock. That is, if the first set of pickets was extended downward and the second set of pickets was extended downward, the two sets of pickets would overlap. When the pickets are used, the area of cut, the effective back rake, and the force applied to each cutter are calculated on a picket-by-picket basis, and the WOB and TOB are calculated by summing the forces on each of the pickets.

Next, the lateral motion drill bit model (i.e., SIDECUT) is discussed. SIDECUT is a program/procedure for calculating the lateral migration dL (with respect to the borehole) of a drill bit drilling a rock formation as a function of drilling depth (dZ) along the borehole. FIG. 33 is a flowchart depicting aspects of the SIDECUT procedure. The drill bit can have

a tilt (with respect to the borehole) and an applied side load that forces the drill bit against the borehole wall. SIDECUT may be used for PDC bits, roller cone bits, and hybrid bits combining aspects of PDC bits and roller cone bits. FIG. 34 depicts aspects of a PDC bit in three-dimensional view.

5 The procedure allows for arbitrary values of: bit rate of penetration (ROP) through the rock formation; bit rotary speed (RPM); bit tilt with respect to the borehole side load applied to the drill bit; bit geometry (gage pad length, gage pad recess, fraction of bit circumference occupied by gage pads); and confined compressive strength (CCS) of rock formation. In one or more embodiments, the CCS is calculated in DRILLBIT, which provides
10 the CCS to SIDECUT.

 The gage pad recess, defined as the radial distance that gage pads are recessed inward from the position of the outermost edge of the ground gage (PDC) trimmers, can vary with respect to vertical position on the gage pad. This allows for tapered, stepped, and other gage pad geometries. FIG. 35 illustrates these aspects in a two-dimensional
15 representation.

 SIDECUT uses a two-dimensional (2D) description of the drill bit and rock formation. The reason for this is computation speed. However, a full three-dimensional (3D) model can be implemented using more computational time. There is excellent agreement between the simplified 2D model and the more sophisticated 3D model.

20 In FIG. 34 the 3D characterization of the PDC bit illustrates the PDC cutters (small cylinders) and the gage pads (rectangular structures). The collection of PDC cutters and associated gage pads is referred to as a “blade.” FIG. 35, the 2D characterization illustrates a single blade and shows the gage pad and PDC cutters (“ground gage trimmers”) below the gage pad. The blade is being forced to the right against the rock with an applied side
25 load. The dotted line in FIG. 35 is the initial rock surface in SIDECUT. The rock is simply “shrink wrapped” to the bit in order to initialize the rock surface and is indicated by the filled region to the right. Note that the outer surface of the gage pad in FIG. 35 is recessed in radial (R) position from the outer edge of the ground gage trimmers. This is referred to as “gage pad recess” and is significant in governing the directional drilling properties of a
30 PDC drill bit. The vertical (Z) extent of the gage pad is called the “gage pad length” and the fraction of the drill bit circumference that is occupied by gage pads is simply referred to as “fraction” in the following discussion.

 SIDECUT accounts for both bit geometry and rock wear in computing the lateral migration of a bit in a bore hole. Rock wear is estimated using a sliding wear model. The

amount of rock worn off at a particular position on the bore hole wall is proportional to the total sliding distance of the gage pads across that position as well as the contact stress applied to that location and the confined compressive strength of the rock formation.

Sliding distance is governed by the bit RPM, ROP, gage pad length and “fraction.” Contact stress is governed by the applied side load and instantaneous rock-pad contact area.

The SIDECUT procedure is now discussed in more detail.

1. Initializations. Drill Bit Construction: Construct the 2D bit by constructing a series of equally spaced (vertically) points or nodes from the top of the gage pad to the bit nose. Differentiate those points associated with the gage pad from those point associated with the PDC cutters. Let the vertical spacing be a prescribed value DZ. The totality of PDC Cutters below the gage pads are represented by a single vertical construction with a prescribed back rake. This series of equally spaced nodes can have an arbitrary shape in R-Z space (see FIG. 35). This generality can therefore encompass tapered and stepped gage pads. The methodology also can allow for a 2D bit profile although the implementation described herein simply assumes a continuous vertical blade as representative of the PDC cutting structure.

Rock Construction: The initial rock surface is a series of equally spaced (vertically) points or nodes that is a clone of the initial drill bit representation. The rock node locations are initially identical to the bit node locations. Assign a stiffness (spring constant) K to the rock. As a gage pad is pushed into the rock, the restoring force by the rock on the gage pad is governed by the depth of penetration of the pad into the rock and that depth is governed by the rock stiffness. The rock stiffness can depend upon rock properties or other parameters as provided by a lithology log, for example. The associated equation for pad-rock contact stress is:

$$\sigma = K \Delta$$

where Δ = pad penetration depth (in) and K = “stiffness” (psi/inch).

2. Processing Loop. The processing loop includes three procedures discussed in the following: force balancing, rock removal and hole growth. At each vertical position of the drill bit with respect to the rock, all three of these procedures are applied in the order given below for this example. The bit is then moved by an amount DZ (see FIG. 15) and the process is repeated until some prescribed drilling distance is achieved. This distance is generally a multiple of the gage pad length.

A. Balance restoring force of rock on bit to equal the applied side load on bit.

Referring to FIG. 35: (a) move the bit laterally; (b) calculate the depth of penetration of the pad into the rock and the PDC cutters in the rock by comparing the lateral (R) positions of the bit nodes with the rock nodes; (c) calculate the forces on the gage pads and PDC cutters on a node-by-node basis according to methodology discussed in a force model below; (d) sum all of the nodal forces (pad and cutter) to get the net restoring force of the rock on the bit and compare with the prescribed side load; (e) calculate the difference between the net restoring force and prescribed side load; and (f) use this difference in a root finding procedure until the net restoring force equals the prescribed side load (go to “a”).

Force on gage pad by a single pad node is now provided. The contact force on a single pad node is:

$$F = \sigma dA$$

where σ is the pad-rock contact stress as presented above and $dA = 2\pi R FR DZ/N$ where R=bit radius, FR=fraction of bit circumference occupied by pads, DZ=vertical node spacing,

N=number of blades on bit, and dA is the total pad area for a single pad over the vertical distance DZ.

Force on PDC cutters by a single rock node is now provided. The restoring force of the rock on the cutter depends on the depth of cut of the cutter into the rock. This force is assumed to be perpendicular to the rock surface for this example. The PDC cutter force model discussed further in the section on DRILLBIT (other cutter force models may also be used), is given by:

$$F_N = \zeta F_T$$

$$F_T = MSE AOC$$

$$MSE = \gamma CCS$$

$$\gamma = 1 + A_2 \tan(EBR)$$

$$\zeta = \tan(EBR + \chi)$$

$$\chi = \tan^{-1} \left(\frac{A_3(90 - 2 EBR)}{90} \right)$$

$$AOC = \Delta dZ$$

where MSE is mechanical specific energy, CCS is the confined compressive strength, AOC is area of cut, EBR is effective back rake, Δ is depth of cut (penetration depth), and A2 and A3 are force model calibration coefficients.

B. Rock removal by gage pads and PDC cutters.

5 At this stage, the restoring force of the rock on the bit has been balanced by the prescribed side load applied to the bit. Rock is removed by the bit either by wearing the rock (pads), crushing the rock (pads) or cutting the rock (PDC cutters). Rock removal is done on a node-by-node basis for all of the nodes representing the bit (pads and cutters).

10 Rock removal by pads. On a node-by node basis on the set of rock nodes that are adjacent to the pads, check to see if the contact stress exceeds the CCS. If so (and this is optional by the user), the rock node can be adjusted to simply reflect displacement. That is, the new R location of the rock node is at the R position of the respective pad node. If the contact stress is less than the CCS, the new rock node R position is governed by the sliding wear model. The amount δ a rock node is moved in the +R direction due to wear is given by:

$$\begin{aligned}\delta &= dx \cos(TILT) \\ dx &= dL \frac{XK}{1 + XB CCS} \left[\frac{\sigma}{CCS} \right]^{XN} \\ dL &= FR 2\pi R RPM \Delta t \\ \Delta t &= 5 \frac{dZ}{ROP}\end{aligned}$$

15

where: TILT=bit tilt (inclination of the bit with respect to the hole axis, radians), dL=sliding distance of pads over a given rock node in one depth step dZ, FR=fraction of bit circumference occupied by pads, RPM=rotary speed, ROP=penetration rate (ft/hr), R=bit radius (in), CCS=confined compressive strength (psi), σ =contact stress at rock node location (see previous) (psi), Δt =length of time for bit to drill the distance dZ (min), dZ=depth step (= prescribed vertical node spacing) (in), and XK, XN, XB are wear model coefficients (lab calibrated). There is no change in the Z coordinate of the rock node. Note also that if the pad node is not contacting its adjacent rock node, the rock node position remains unchanged.

25 Rock removal by cutters. The Z-coordinate of the rock node does not change but the “new” R position of the rock node is simply the outer position of the cutter. That is, the lateral position of the “cutter” nodes on the bit, which must be greater (larger R coordinate) than the adjacent rock node. If not, nothing is cut and the rock node remains unchanged.

C. Borehole growth.

The final piece of the computation is to grow the borehole by the amount dZ . This is done only at the end of going through all of the rock nodes and removing rock according to the previous section. Recall that dZ is the prescribed vertical node spacing for both the bit and the rock. So once the rock is removed according to the previous section, a single rock node is added. If at this point there are N rock nodes, then:

$$R(N + 1) = R(N) + dZ \tan(TILT)$$

$$Z(N + 1) = Z(N) - dZ$$

It is noted that the $R(N)$ above already takes into account the rock removal described in the previous section. Also note that the Z coordinate is positive-up. That is why the “- dZ ” in the new rock node is in a vertical position.

Rather than actually move the bit down for the next time step, the indices of the rock are simply adjusted. As an example, the penetration depth Δ of the pad at rock node k is:

$$\Delta(k) = PAD_R(j) - ROCK_R(k), \quad k = j + ISHIFT$$

where the depth of the rock node is $Z = (j + ISHIFT - 1) \times dZ$. The top of the pad is aligned with the top of the rock when $ISHIFT = 0$. J is an index that simply spans the pad nodes as originally set up. This technique, along with the fact that this is a static 2D model rather than a dynamic 3D model, is why SIDECUT runs quickly on a computer processing system.

3. Post analysis. At this point, the lateral displacement L of the bit as a function of drilling depth Z is obtained. A line is fit to this data to get the slope dL/dZ which is a measure of the lateral aggressivity of the bit for the conditions prescribed for the simulation. This line-fitting procedure is automated within SIDECUT.

FIG. 35 illustrates rock and drill bit geometry half-way through a SIDECUT simulation of drilling a borehole. FIG. 36 illustrates a graph of axial depth versus lateral side cut for the simulation illustrated in FIG. 35. FIG. 37 illustrates results of force balancing at each depth step during a SIDECUT simulation with a prescribed side load of 800 lbs. (362.9 Kg) FIG. 37 illustrates the sensitivity of gage pad contact area to bit RPM and gage pad length. FIG. 38 illustrates aspects of a comparison of SIDECUT predictions with measured laboratory side load drilling experiments in Bedford limestone.

FIG. 39 is a flowchart for a method 390 for predicting a change in lateral displacement with a change in axial displacement of a drill bit drilling in a formation rock. Block 391 calls

for constructing a virtual representation of the drill bit and the formation rock, the drill bit comprising a gage pad configured to remove rock by wearing or crushing the rock during moving contact and a cutter configured to cut into rock during moving contact. Block 392 calls for adjusting lateral penetration depth until rock reactive force equals a side force applied to the drill bit to provide a lateral displacement of the drill bit to provide an adjusted lateral penetration depth. Block 393 calls for removing formation rock to where the pad and the cutters contact the formation rock at the adjusted lateral penetration depth and to a selected axial displacement of the drill bit. Block 394 calls for moving the drill bit in a drilling direction to the end of the currently drilled borehole. Block 395 calls for iterating the adjusting, the removing, and the moving to predict the change in lateral displacement with the change in axial displacement of the drill bit. The method 390 may also include using a first set of nodes as representation of the drill bit and a second set of nodes as a representation of the rock formation. The method 390 may further include setting the selected axial displacement as the axial distance between two nodes in the axial direction. The method 390 may further include initializing the nodes such that the nodes at the boundary of the drill bit with the rock formation overlap.

Next, improvements in the DDAS are discussed, which include additional models to account for and predict bit walk and/or wellbore spiraling of drill bits and BHA systems during directional drilling applications. One embodiment, referred to herein as a “Constant Bit Walk Model,” supplements the drillstring steering model of the DDAS by changing the contact force (i.e., the applied side load) by rotating the contact force by a constant angle. Another embodiment, referred to herein as a “Torsional Friction Bit Walk Model,” supplements the drillstring steering model of the DDAS by accounting for torsional friction between components of the drillstring and the walls of the wellbore in calculating the net contact force (i.e., the applied side load) in each calculation of the processing loop.

In the Constant Bit Walk Model, historical laboratory drilling data is used to determine the actual walk behavior of a particular bottomhole assembly. For example, historical data may show that a particular BHA will walk 12° to the left. Using this historical information, the contact force (i.e., the applied side load) in the drillstring steering model of the DDAS may be rotated by the same or substantially the same degree (e.g., 12°) so as to account for bit walk in the simulation calculations. In other words, the direction of the contact forces on the drill bit may be rotated, for example, in a counterclockwise direction from a perspective looking down the borehole to account for left bit walk. The constant angle may be based on properties of a designated subterranean

formation and/or on testing for bit walk characteristics in a specific drill bit. In some embodiments, the constant angle may be obtained by calculating the constant angle with an empirical formula. In other embodiments, the constant angle may be obtained from a table of known values, for example, formation properties and/or bit walk characteristics.

- 5 Alternatively, the constant angle may be obtained by using a value equal to an angle between the contact forces and the frictional forces at the drill bit.

In the Torsional Friction Bit Walk Model, the finite element analysis (FEA) computations used in the “force balancing” component of the BHA finite element program/procedure may include calculating the torsional friction between components of the drillstring (e.g., gage pads) and the walls of the wellbore, which modifies the direction and the magnitude of the net contact force (i.e., the applied side load) in each calculation of the processing loop. The torsional frictional forces may be calculated using the formula:

$$F_f = F_n * \text{FricCoefficient},$$

- 15 where F_f represents the torsional frictional forces, F_n represents the normal contact forces and FricCoefficient represents a frictional factor.

In some embodiments, an individual frictional factor may be assigned to one or more individual components of the BHA. Further, the accounting of the torsional friction in the calculations may also affect displacements such as angular displacement (i.e., tilt angle) of the drill bit, which may further affect bit walk, as described in further detail below with respect to FIG. 45.

FIG. 40 is a process flowchart for a DDAS method 400, including the additional models (i.e., the Constant Bit Walk Model and the Torsional Friction Bit Walk Model) to account for and predict bit walk and/or wellbore spiraling. As described above with reference to FIG. 4, the BHA model may provide forces, drill bit tilt, moments, and curvature information to the axial motion drill bit model and lateral motion drill bit model at 402. The BHA model may also provide hole curvature and BHA alignment within the hole to the steering computer model (i.e., drillstring steering model or steering algorithm). Further, the BHA model may operate in a drill-ahead depth domain within the DDAS.

30 At 404, the BHA model may calculate BHA contact forces (F_n) and/or drill bit angular displacements, including tilt. Both the tilt of the drill bit (with respect to the borehole) and an applied side load that forces the drill bit against the borehole wall are accounted for in the SIDECUT procedure. At 406, BHA frictional forces (F_f) may be calculated by applying frictional force values to one or more components of the BHA (e.g., gage pads, ribs, steering

devices, etc.) either individually or collectively. At 408, the BHA model may then apply the calculated frictional forces to the BHA in each iteration of the DDAS using the FEA with error-reducing iterations and may calculate final values for angular displacement, contact forces, and/or frictional forces. In this manner, the torsional frictional forces between the borehole wall and the drill bit and/or the BHA may be calculated and applied to predict BUR and walk rate.

At 414, the axial motion drill bit model may use inputs from formation lithology data (shown at 412) and drill rig operating parameters (shown at 410). As mentioned above, the axial motion drill bit model may calculate rock strength and ROP, which calculations may then be given to the lateral motion drill bit model. At 416, the lateral motion drill bit model may use the rock strength and ROP data from the axial motion drill bit model along with the data supplied by the BHA model, such as bit side force and bit tilt, for example, to calculate the ratio of lateral ROP to axial ROP, or in the alternative, to calculate the ratio of lateral displacement to axial displacement for the drill bit for a certain depth or certain time period, as described in greater detail above with reference to FIG. 4.

At 418, the steering computer model may include the front steering angle model, or optionally, the rear steering angle model, as explained in greater detail above with reference to FIGS. 5A through 8. In order to account for and predict bit walk and/or wellbore spiraling, the steering computer model may, in some embodiments, rotate the contact force at the drill bit by a constant walk angle. Alternatively, or additionally, the steering computer model may account for frictional forces by applying the lateral motion drill bit model side-cutting results in the direction of the rotated contact force at the drill bit.

At 420, the steering computer model may then use the updated models to calculate inclination and azimuth for the end of a new hole section to be created. At 422, a new hole section may be created based on the calculated inclination and azimuth. At 424, the drillstring (i.e., BHA and drill bit) may then be moved down to the bottom of the new borehole section and the three models (BHA model, axial motion drill bit model and lateral motion drill bit model) may be invoked again at the start of the next iteration (shown at 426). Thus, the cycle continues until the simulation is stopped. In other words, the drill-ahead simulation method runs the BHA model first, then feeds its results to the axial motion and lateral motion drill bit models, which models may be incorporated into the DDAS method. The DDAS method then predicts the location and geometry of the next hole section. As mentioned above, it is to be appreciated that alternate ways or sequences of running the models may be used. However, regardless of the process or order, the steering

computer model may be supplied information by the other models, including the Constant Bit Walk Model and the Torsional Friction Bit Walk Model, and a new simulated hole section may be placed in the direction that the bit/BHA system wants to drill as calculated by the steering computer model. It is to be appreciated that initial conditions and past behavior along with forces on the drill bit and/or BHA affect the future behavior of the drill bit trajectory.

Furthermore, any combination of model or models for accounting for and predicting bit walk and/or wellbore spiraling may be used by the steering computer model. For example, the Constant Bit Walk Model and the Torsional Friction Bit Walk Model may be applied separately or in combination. In some embodiments, the original DDAS method (i.e., not accounting for bit walk and/or wellbore spiraling) may apply lateral motion drill bit model side-cutting results in the direction of the contact force (F_n) at the drill bit, along with accounting for angular displacements. Alternatively, the torsional frictional forces (F_t) may be applied to the BHA model in order to supplement the original DDAS method. In other embodiments, a user may input a constant angle to rotate the contact force at the drill bit by the predicted walk angle. In yet other embodiments, a computer program may calculate a walk angle with, for example, an empirical formula or a table of known values for formation properties and/or drill bit configurations. Alternatively, the walk angle may be updated automatically within the computer program according to a defined function of certain parameters of the BHA. For example, gage pad length, lateral force on the drill bit, friction factor, ROP, RMP, etc., may be factored into an equation, either separately or in combination, for calculating the bit walk angle. In further embodiments, the walk angle may be calculated by assuming the walk angle is equal to the angle between the contact force and frictional force at the drill bit. It is to be appreciated that any type of user inputted or calculated value may be used to adjust the angle of the contact force.

FIG. 41 is a simplified drawing of a downhole view 500 of the borehole 2 shown in FIG. 1. An end view of the drill tubular 5 followed by the drill bit 7 is depicted from looking downhole. As illustrated, the drill bit 7 is tilted in an arbitrary direction due to a lateral contact force 504 in an arbitrary direction. In the Constant Bit Walk Model, the lateral contact force 504 calculated and employed in the BHA finite element program/procedure of the DDAS may be rotated by a constant angle θ to a rotated contact force 506 in each iteration of the processing loop. The value of the constant angle θ may be selected empirically based on laboratory or field data of actual bit walk angles, such that the results of the simulation align with the historical data for the same or substantially similar BHA designs. In the embodiment of FIG. 41, the rotated contact force 506 is shown to be rotated counterclockwise of the lateral

contact force 504. In the Constant Bit Walk Model, the change in the rotation of the lateral contact force 504 may be the only programming change made to the DDAS. By way of example and not limitation, the constant angle θ may be between about 10° and about 20° , and more particularly, between about 12° and about 15° . As one non-limiting example
5 embodiment, the constant angle θ may be about 12° .

FIGS. 42A through 42K contain a series of graphs illustrating results for the system walk for the entire BHA system using the Constant Bit Walk Model in the DDAS. Results are shown for left-hand bit walk (negative turn rate) while building with the AUTOTRAKTM eXact Rotary Steerable System (RSS), which is commercially available from Baker Hughes
10 Incorporated of Houston, TX. In some embodiments, the DDAS may be programmed with a constant 12° bit walk angle. Various results versus measured depth (MD) are illustrated. FIG. 42A illustrates inclination versus MD, FIG. 42B illustrates azimuth versus MD, FIG. 42C illustrates build-up-rate (BUR) versus MD, FIG. 42D illustrates turn rate versus MD, FIG. 42E illustrates dogleg severity (DLS) versus MD, and FIG. 42F illustrates first
15 contact force versus MD. Various parameters versus MD are illustrated. FIG. 42G illustrates rate of penetration (ROP) versus MD, FIG. 42H illustrates drill bit rotary speed (RPM) versus MD, FIG. 42I illustrates weight-on-bit (WOB) versus MD, FIG. 42J illustrates rib force versus MD, and FIG. 42K illustrates rib orientation versus MD. Upon review, the results demonstrated that the DDAS method including the Constant Bit Walk Model predicted
20 behavior consistent with observed behavior in laboratory tests.

FIGS. 43A through 43K contain a series of graphs illustrating results for the system walk rate for the entire BHA system using the Constant Bit Walk Model in the DDAS. Results are shown for right-hand bit walk (positive turn rate) while dropping with the AUTOTRAKTM eXact RSS. In some embodiments, the DDAS may also be programmed with a
25 constant 12° bit walk. Various results versus MD are illustrated. FIG. 43A illustrates inclination versus MD, FIG. 43B illustrates azimuth versus MD, FIG. 43C illustrates BUR versus MD, FIG. 43D illustrates turn rate versus MD, FIG. 43E illustrates DLS versus MD, and FIG. 43F illustrates first contact force versus MD. Various parameters versus MD are illustrated. FIG. 43G illustrates ROP versus MD, FIG. 43H illustrates RPM versus MD,
30 FIG. 43I illustrates WOB versus MD, FIG. 43J illustrates rib force versus MD, and FIG. 43K illustrates rib orientation versus MD. Upon review, the results demonstrated that the DDAS method including the Constant Bit Walk Model predicted behavior consistent with observed behavior in laboratory tests.

FIG. 44A is a simplified drawing of a top view of a wellbore spiral 600, and FIG. 44B is a simplified drawing of a side view of the wellbore spiral 600 of FIG. 44A. A spiraled (i.e., corkscrew) hole is a well-known phenomenon in the industry and may be measured by lateral distance 602 (side movement) per measured depth 604, as shown in FIG. 44B. A right-handed spiral 606 is illustrated in FIG. 44B. While a drill bit primarily exhibits bit walk to the left due to a drill tubular being rotated in a clockwise rotation, wellbore spiraling has been observed as exhibiting both a left-handed thread and a right-handed thread. Detailed information regarding wellbore spiraling may be found in “Borehole Quality Design and Practices to Maximize Drill Rate Performance,” by F.E. Dupriest et al., Society of Petroleum Engineers, 2010, the disclosure of which is hereby incorporated herein in its entirety by this reference.

While wellbore spiraling exists in many boreholes, it is generally avoided due to negative impacts and complications, such as improper casing placement. Wellbore spiraling can usually be detected from wellbore logs. In the past, attempts have been made to predict and correct for wellbore spiraling, which is more pronounced in horizontal legs and in laterally aggressive systems. In addition to predicting bit walk, the Constant Bit Walk Model may be utilized to predict wellbore spiraling. In one embodiment, a 12° correction factor may be implemented in the Constant Bit Walk Model. In this embodiment, modeling may be used to predict wellbore spiraling behavior in addition to bit walk behavior. In the lab, spiraling behavior was observed in lateral simulations with the AUTOTRAK™ eXact RSS when a rib force was set to 0 percent. A right-handed thread spiral wellbore was primarily observed. Once spiraling behavior is predicted through modeling, the results may be used to account for the predicted behavior and to take corrective action. For example, longer-gauge bits or bits that are less aggressive laterally may tend to help reduce wellbore spiraling.

As previously mentioned, in the Torsional Friction Bit Walk Model, the computations used in the “force balancing” component of the BHA model may include calculation of the torsional friction between components of the drillstring and the walls of the wellbore, which modifies the direction and the magnitude of the net contact force (i.e., the applied side load) in each calculation of the processing loop. For example, dynamic modeling software, including BHASYS, BHASYS PRO AND BHASYS TD software of Baker Hughes Incorporated, Houston, TX, may be used to calculate torsional friction between components of the BHA and the wellbore. In addition, wellbore spiraling may also be predicted using the Torsional Friction Bit Walk Model, the results of which may be used to take corrective action based on accounting for the predicted spiraling behavior.

FIG. 45 is a simplified transverse cross-sectional view 700 of a BHA in a wellbore, and illustrates force vectors acting on the BHA. In FIG. 45, the drill tubular 5 and drill bit 7 are disposed in a horizontal leg of the borehole 2. Longitudinal axis 702 represents the vertical leg of the borehole 2, prior to building to the horizontal leg. The normal force vector 704 represents the direction and magnitude of normal contact forces on the drill bit 7 as calculated in the previous DDAS software. In the Torsional Friction Bit Walk Model, a torsional friction force vector 706 is calculated and summed with the normal force vector 704, resulting in a resultant vector 708 having a direction and magnitude different from the normal force vector 704. The torsional friction force vector 706 represents the direction and magnitude of frictional forces that are tangential to the borehole 2 and perpendicular to the normal contact forces and represents frictional forces that occur between components of the BHA and the wall of the borehole 2. In a build scenario exhibiting left bit walk, the drill bit 7 may roll to the left, which is illustrated as the normal force vector 704 being displaced from vertical in FIG. 45. The torsional friction forces due to bit rotation, represented by the torsional friction force vector 706, may also cause further displacement of the drill bit 7 from alignment with the longitudinal axis 702. In one embodiment, the normal force vector 704 and the torsional friction force vector 706 may be added as is commonly done in vector addition. The resultant vector 708 represents the combined forces and may be used in the Torsional Friction Bit Walk Model of the DDAS software, which has been found to accurately predict and account for bit walk and/or wellbore spiraling. In some embodiments, the tangential friction forces are calculated using a friction factor. Finally, the drill bit 7 may also exhibit tilt as a result of the forces, which, in turn, may add additional displacement forces. In drilling, and more particularly in direction drilling, it is well known in the art that as more force is applied to a lateral side of the drill bit 7, the faster the drill bit 7 will drill laterally.

FIG. 46 contains a series of graphs illustrating results for bit walk using the Torsional Friction Bit Walk Model in the DDAS. Results are shown for left-hand bit walk in the build direction while executing a 90° turn in a lateral direction with an RSS. Various results versus MD are illustrated in FIG. 46, including hole inclination versus MD, azimuth versus MD, BUR versus MD, and turn rate versus MD. Modeling may be provided comparing a friction coefficient to walk rates in building and dropping scenarios. For example, models may include results of walk rates while turning 90° and 270° rib orientation. Alternatively, models may include results of walk rates while building and dropping 0° and 180° rib orientation. For example, results may show that a slight build is natural for a certain BHA when turning left or

right. In particular, the results of this scenario may show a 1.5° build for a left or a right turn, which may be due to gravity impacting a lateral side of the drill bit 7 and/or due to tilt in the build direction. Once friction is introduced into the system, a 90° right-turning BHA may walk left where it is being pushed, for example, resulting in a greater build. Alternatively, a
5 270° left-turning BHA may walk “less right” resulting in less build and may eventually exhibit a “true” walk left at a friction coefficient of about 0.25, for example.

In the simulations used to generate the data in the graphs shown in FIG. 46, calculations were made using friction coefficients of 0, 0.1, 0.25, and 0.4, which resulted in calculated walk rates of 1.6°/100 ft. (1.6°/30.48 m), 1.9°/100 ft. (1.9°/30.48 m), 2.2°/100 ft.
10 (2.2°/30.48 m), and 2.6°/100 ft. (2.6°/30.48 m), respectively. In one example, a friction coefficient of around 0.3 results in a bit force walk angle on the AUTOTrak™ eXact RSS of about 15 degrees, which is consistent with laboratory tests.

Once predictions for bit walk and wellbore spiraling are made using the modeling and simulation techniques disclosed herein, adjustments and/or modifications may be made to the
15 wellbore plan, the BHA configuration, tool components, etc., so as to ensure that the results of the drilling process match the wellbore plan. For example, a drilling services company may employ the DDAS as disclosed herein to make recommendations to drilling operators to modify the design of the BHA, drill bit, drilling parameters or the wellbore plan to improve the directional drilling process. For example, selecting or adjusting parameters may include
20 adjusting weight-on-bit, torque applied to a drillstring of the BHA, rotary speed of the drillstring, rate of penetration, or drilling fluid flow rate. In addition, adjusting lateral aggressiveness of the drill bit may include, by way of non-limiting example, adjusting gauge of the drill bit, blade configuration, gage pad length, gage pad location, or cutting element placement on the drill bit. The drill bit trajectory may be adjusted during drilling with a rotary
25 steering drilling system connected to the BHA, which may be configured, for example, to adjust the drill bit trajectory based at least in part on calculations from the BHA model. It is to be appreciated that receiving parameters for operating the BHA may include receiving drilling parameters specific to the BHA and receiving lithology data may include receiving lithology data specific to a defined target in the subterranean formation. The drilling parameters and
30 lithology data may be received either prior to drilling and/or in real time during drilling operations. In addition, adjustments and/or modifications to the wellbore plan and the BHA system may be made prior to drilling and/or in real time during drilling operations.

Additional non-limiting example embodiments of the disclosure are described below.

Embodiment 1: A method of controlling drill bit trajectory in a subterranean formation, the method comprising: receiving drilling parameters for operating a specific bottomhole assembly (BHA); constructing, with a computer processor, a directional drill-ahead simulator comprising a computer model of the BHA and the subterranean formation; calculating, with the computer processor, axial motion and lateral motion of a drill bit connected to a bottom end of the BHA using at least one formation parameter and at least one drilling parameter; predicting, with the computer processor, bit walk of the drill bit by accounting for and calculating contact forces and frictional forces between the BHA and a wall of a borehole in the subterranean formation using the computer model of the BHA; determining, with the computer processor, an adjusted drill bit trajectory to account for the predicted bit walk; determining adjusted drilling parameters for operating the BHA to substantially follow the adjusted drill bit trajectory; and operating the BHA according to the adjusted drilling parameters.

Embodiment 2: The method of Embodiment 1, further comprising predicting wellbore spiraling by accounting for and calculating the contact forces and the frictional forces using the computer model of the BHA.

Embodiment 3: The method of Embodiment 1, wherein constructing the directional drill-ahead simulator comprising the BHA computer model comprises: constructing a three-dimensional model of the BHA and the subterranean formation; configuring the BHA computer model to be a dynamic model in a depth domain; configuring the BHA computer model to predict a build-up-rate based at least in part on the predicted bit walk of the drill bit using error-reducing iterations in each step of a finite element analysis; and configuring the BHA computer model to operate in real time during drilling operations.

[0001] Embodiment 4: The method of Embodiment 1, wherein: calculating the axial motion and the lateral motion of the drill bit comprises using a lateral motion drill bit model based at least in part on the axial motion of the drill bit calculated using an axial motion drill bit model separate from the lateral motion drill bit model and the computer model of the BHA; and determining the adjusted drill bit trajectory comprises using a steering computer model separate from the lateral motion drill bit model and the axial motion drill bit model, wherein the steering computer model is configured to apply results from the lateral motion drill bit model adjusted by the predictions of the computer model of the BHA.

Embodiment 5: The method of Embodiment 1, wherein determining the adjusted drill bit trajectory further comprises: calculating a new inclination angle and a new azimuth angle of the drill bit; adding a distance to the borehole in the subterranean formation; moving the

drill bit in a drilling direction to an end of the borehole; and iterating the calculating, the adding, and the moving to update the computer model of the BHA.

Embodiment 6: The method of Embodiment 1, wherein predicting the bit walk of the drill bit by accounting for and calculating the contact forces and the frictional forces
5 between the BHA and the wall of the borehole further comprises accounting for angular displacement of the drill bit.

Embodiment 7: The method of Embodiment 1, wherein predicting the bit walk of the drill bit by accounting for and calculating the contact forces and the frictional forces between the BHA and the wall of the borehole further comprises calculating torsional frictional forces
10 between at least one component of the BHA and the wall of the borehole.

Embodiment 8: The method of Embodiment 1, wherein determining the adjusted drill bit trajectory comprises applying calculations of the lateral motion of the drill bit in a direction of the contact forces and rotating the direction of the contact forces on the drill bit by a constant angle.

15 Embodiment 9: The method of Embodiment 8, wherein rotating the direction of the contact forces on the drill bit by a constant angle further comprises obtaining the constant angle by at least one of calculating the constant angle with an empirical formula, obtaining the constant angle from a table of known values, or using a value equal to an angle between the contact forces and the frictional forces at the drill bit.

20 Embodiment 10: The method of Embodiment 8, wherein rotating the direction of the contact forces on the drill bit by a constant angle comprises rotating the direction of the contact forces on the drill bit by about 12° in a counterclockwise direction from a perspective looking down the borehole.

Embodiment 11: The method of Embodiment 1, wherein determining the adjusted
25 drilling parameters for operating the BHA comprises: adjusting lateral aggressiveness of the drill bit by adjusting at least one of gauge of the drill bit, blade configuration, gage pad length, gage pad location, or cutting element placement on the drill bit; adjusting at least one of weight-on-bit, torque applied to a drillstring of the BHA, rotary speed of the drillstring, rate of penetration, or drilling fluid flow rate; and adjusting the drill bit
30 trajectory during drilling with a rotary steering drilling system operably connected to the BHA.

Embodiment 12: A method of planning and drilling a wellbore in a subterranean formation, comprising: defining a target in a designated subterranean formation; predicting wellbore spiraling and bit walk of a drill bit connected to a specific bottomhole assembly

(BHA), comprising: using a computer processor programmed to execute a directional drill-ahead simulator comprising a computer model of the BHA and the designated subterranean formation; receiving with the computer processor lithology data and drilling parameters for operating the BHA in the designated subterranean formation; calculating with the computer processor a ratio of lateral motion to axial motion using a lateral motion drill bit computer model and an axial motion drill bit computer model; predicting drill bit trajectory with the computer processor by accounting for and calculating lateral contact forces, angular displacement, and frictional forces using the computer model of the BHA; and adjusting the drill bit trajectory with the computer processor based at least in part on predictions from the computer model of the BHA; adjusting the drilling parameters for operating the BHA to substantially follow the adjusted drill bit trajectory; and drilling the wellbore in the designated subterranean formation based at least in part on the adjusted drill bit trajectory.

Embodiment 13: The method of Embodiment 12, further comprising updating the drilling parameters during drilling using information received from at least one sensor connected to the BHA.

Embodiment 14: The method of Embodiment 12, wherein predicting the drill bit trajectory comprises calculating the frictional forces between at least one component of the BHA and a borehole wall and adding the frictional forces to the lateral contact forces.

Embodiment 15: The method of Embodiment 12, wherein adjusting the drill bit trajectory comprises rotating a direction of a lateral contact force on the drill bit by a constant angle, wherein the constant angle is based on properties of the subterranean formation and on testing for bit walk characteristics in a specific drill bit.

Embodiment 16: The method of Embodiment 12, wherein adjusting the drilling parameters for operating the BHA further comprises: selecting components of the BHA based at least in part on the predictions for the wellbore spiraling and the bit walk of the drill bit; adjusting at least one of weight-on-bit, torque applied to a drillstring of the BHA, rotary speed of the drillstring, rate of penetration, or drilling fluid flow rate; and adjusting lateral aggressiveness of the drill bit by adjusting at least one of gauge of the drill bit, blade configuration, gage pad length, gage pad location, or cutting element placement on the drill bit.

Embodiment 17: The method of Embodiment 12, wherein adjusting the drilling parameters for operating the BHA comprises adjusting the drilling parameters using a rotary steering drilling system.

Embodiment 18: A method of controlling drill bit trajectory in a subterranean formation, the method comprising: receiving lithology data for a specific subterranean formation; receiving one or more drilling parameters for operating a bottomhole assembly (BHA), the one or more drilling parameters comprising at least one of weight-on-bit, torque, rotary speed, rate of penetration, drilling fluid flow rate, or lateral aggressiveness of a drill bit; predicting wellbore spiraling and bit walk of a drill bit of the BHA, comprising: constructing, with a computer processor, a directional drill-ahead simulator comprising a dynamic computer model of the BHA and the subterranean formation; accounting for the wellbore spiraling and the bit walk of the drill bit by rotating a direction of normal contact forces on the drill bit by a constant angle using the computer processor; calculating combined forces on the BHA by adding torsional frictional forces to the normal contact forces in the dynamic computer model of the BHA in each iteration of a finite element analysis using the computer processor; predicting the drill bit trajectory, with the computer processor, based at least in part on calculating the combined forces on the BHA; and adjusting the drill bit trajectory, with the computer processor, based at least in part on predictions for the drill bit trajectory; and adjusting the one or more drilling parameters based at least in part on predictions for the wellbore spiraling and the bit walk of the drill bit.

Embodiment 19: The method of Embodiment 18, wherein calculating the combined forces on the BHA comprises calculating the torsional frictional forces using:
 $F_f = F_n * \text{FricCoefficient}$, wherein F_f represents the torsional frictional forces, F_n represents the normal contact forces and FricCoefficient represents a frictional factor; and wherein an individual frictional factor may be assigned to one or more individual components of the BHA.

Embodiment 20: The method of Embodiment 18, wherein adjusting the drill bit trajectory comprises adjusting the drill bit trajectory with a rotary steering drilling system operably connected to the BHA, the rotary steering drilling system configured to adjust the drill bit trajectory based at least in part on calculations from the dynamic computer model of the BHA.

Although the foregoing description contains many specifics, these are not to be construed as limiting the scope of the present invention, but merely as providing certain exemplary embodiments. Similarly, other embodiments of the invention may be devised that do not depart from the spirit or scope of the present disclosure. For example, features described herein with reference to one embodiment also may be provided in others of the embodiments described herein. The scope of the invention is, therefore, indicated and limited

- 48 -

only by the appended claims and their legal equivalents, rather than by the foregoing description. All additions, deletions, and modifications to the disclosed embodiments, which fall within the meaning and scope of the claims, are encompassed by the present disclosure.

CLAIMS

What is claimed is:

- 5 1. A method of controlling drill bit trajectory in a subterranean formation, the method comprising:
receiving drilling parameters for operating a specific bottomhole assembly (BHA);
constructing, with a computer processor, a directional drill-ahead simulator comprising a
computer model of the BHA and the subterranean formation;
10 calculating, with the computer processor, axial motion and lateral motion of a drill bit
connected to a bottom end of the BHA using at least one formation parameter and at
least one drilling parameter;
predicting, with the computer processor, bit walk of the drill bit by accounting for and
calculating contact forces and frictional forces between the BHA and a wall of a
15 borehole in the subterranean formation using the computer model of the BHA;
determining, with the computer processor, an adjusted drill bit trajectory to account for the
predicted bit walk;
determining adjusted drilling parameters for operating the BHA to substantially follow the
adjusted drill bit trajectory; and
20 operating the BHA according to the adjusted drilling parameters.
2. The method according to claim 1, further comprising predicting wellbore
spiraling by accounting for and calculating the contact forces and the frictional forces using
the computer model of the BHA.
- 25 3. The method according to claim 1 or 2, wherein receiving drilling parameters
further comprises receiving lithology data for operating the specific BHA in a designated
subterranean formation.
- 30 4. The method according to claim 3, wherein operating the BHA according to the
adjusted drilling parameters comprises drilling a wellbore in the designated subterranean
formation based at least in part on the adjusted drill bit trajectory.

- 50 -

5. The method according to claim 1 or 2, wherein constructing the directional drill-ahead simulator comprising the BHA computer model comprises:
constructing a three-dimensional model of the BHA and the subterranean formation;
configuring the BHA computer model to be a dynamic model in a depth domain;
5 configuring the BHA computer model to predict a build-up-rate based at least in part on the predicted bit walk of the drill bit using error-reducing iterations in each step of a finite element analysis; and
configuring the BHA computer model to operate in real time during drilling operations.
- 10 6. The method according to claim 1 or 2, wherein:
calculating the axial motion and the lateral motion of the drill bit comprises using a lateral motion drill bit model based at least in part on the axial motion of the drill bit calculated using an axial motion drill bit model separate from the lateral motion drill bit model and the computer model of the BHA; and
15 determining the adjusted drill bit trajectory comprises using a steering computer model separate from the lateral motion drill bit model and the axial motion drill bit model, wherein the steering computer model is configured to apply results from the lateral motion drill bit model adjusted by the predictions of the computer model of the BHA.
- 20 7. The method according to claim 6, wherein calculating the axial motion and the lateral motion of the drill bit comprises calculating a ratio of the lateral motion to the axial motion using the lateral motion drill bit computer model and the axial motion drill bit computer model.
- 25 8. The method according to claim 1 or 2, wherein predicting the bit walk of the drill bit by accounting for and calculating the contact forces and the frictional forces between the BHA and the wall of the borehole further comprises accounting for angular displacement of the drill bit.
- 30 9. The method according to claim 1 or 2, wherein predicting the bit walk of the drill bit comprises calculating the frictional forces between at least one component of the BHA and a borehole wall and adding the frictional forces to the contact forces.

10. The method according to claim 1 or 2, wherein predicting the bit walk of the drill bit by accounting for and calculating the contact forces and the frictional forces between the BHA and the wall of the borehole further comprises calculating torsional frictional forces between at least one component of the BHA and the wall of the borehole.

5

11. The method according to claim 10, wherein predicting the bit walk of the drill bit by accounting for and calculating the contact forces and the frictional forces further comprises calculating the torsional frictional forces using:

$$F_f = F_n * \text{FricCoefficient},$$

10 wherein F_f represents the torsional frictional forces, F_n represents normal contact forces and FricCoefficient represents a frictional factor; and wherein an individual frictional factor may be assigned to one or more individual components of the BHA.

15 12. The method according to claim 1 or 2, wherein determining the adjusted drill bit trajectory further comprises:
calculating a new inclination angle and a new azimuth angle of the drill bit;
adding a distance to the borehole in the subterranean formation;
moving the drill bit in a drilling direction to an end of the borehole; and
20 iterating the calculating, the adding, and the moving to update the computer model of the BHA.

13. The method according to claim 1 or 2, wherein determining the adjusted drill bit trajectory comprises applying calculations of the lateral motion of the drill bit in a direction
25 of the contact forces and rotating the direction of the contact forces on the drill bit by a constant angle.

14. The method according to claim 13, wherein rotating the direction of the contact forces on the drill bit by a constant angle further comprises obtaining the constant
30 angle by at least one of calculating the constant angle with an empirical formula, obtaining the constant angle from a table of known values, or using a value equal to an angle between the contact forces and the frictional forces at the drill bit.

15. The method according to claim 13, wherein rotating the direction of the contact forces on the drill bit by a constant angle comprises rotating the direction of the contact forces on the drill bit by about 12° in a counter-clockwise direction from a perspective looking down the borehole.

5

16. The method according to claim 1 or 2, wherein determining the adjusted drilling parameters for operating the BHA comprises:

adjusting lateral aggressiveness of the drill bit by adjusting at least one of gauge of the drill bit, blade configuration, gage pad length, gage pad location, or cutting element placement on the drill bit;

10

adjusting at least one of weight-on-bit, torque applied to a drillstring of the BHA, rotary speed of the drillstring, rate of penetration, or drilling fluid flow rate; and
adjusting the drill bit trajectory during drilling with a rotary steering drilling system operably connected to the BHA.

15

17. The method according to claim 16, wherein adjusting the drill bit trajectory during drilling with the rotary steering drilling system comprises adjusting the drill bit trajectory based at least in part on calculations from the computer model of the BHA.

20

18. The method according to claim 1 or 2, further comprising updating the drilling parameters during drilling using information received from at least one sensor connected to the BHA.

25

19. The method according to claim 1 or 2, wherein operating the BHA according to the adjusted drilling parameters further comprises:

selecting components of the BHA based at least in part on the predictions for the wellbore spiraling and the bit walk of the drill bit;

adjusting at least one of weight-on-bit, torque applied to a drillstring of the BHA, rotary speed of the drillstring, rate of penetration, or drilling fluid flow rate; and

30

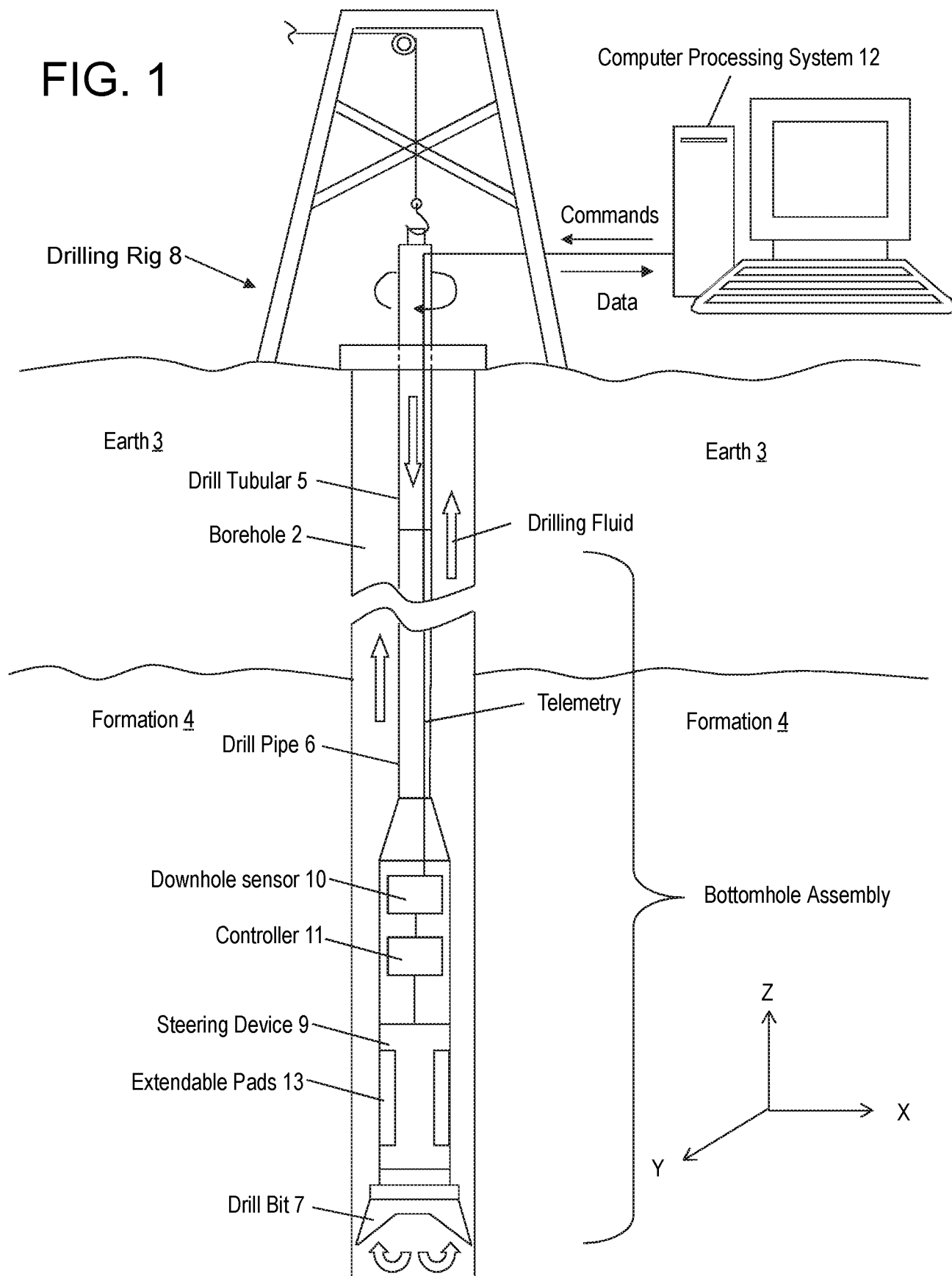
adjusting lateral aggressiveness of the drill bit by adjusting at least one of gauge of the drill bit, blade configuration, gage pad length, gage pad location, or cutting element placement on the drill bit.

- 53 -

20. The method according to claim 1 or 2, wherein operating the BHA according to the adjusted drilling parameters comprises adjusting at least one of weight-on-bit, torque, rotary speed, rate of penetration, drilling fluid flow rate, or lateral aggressiveness of a drill bit.

1/37

FIG. 1



2/37

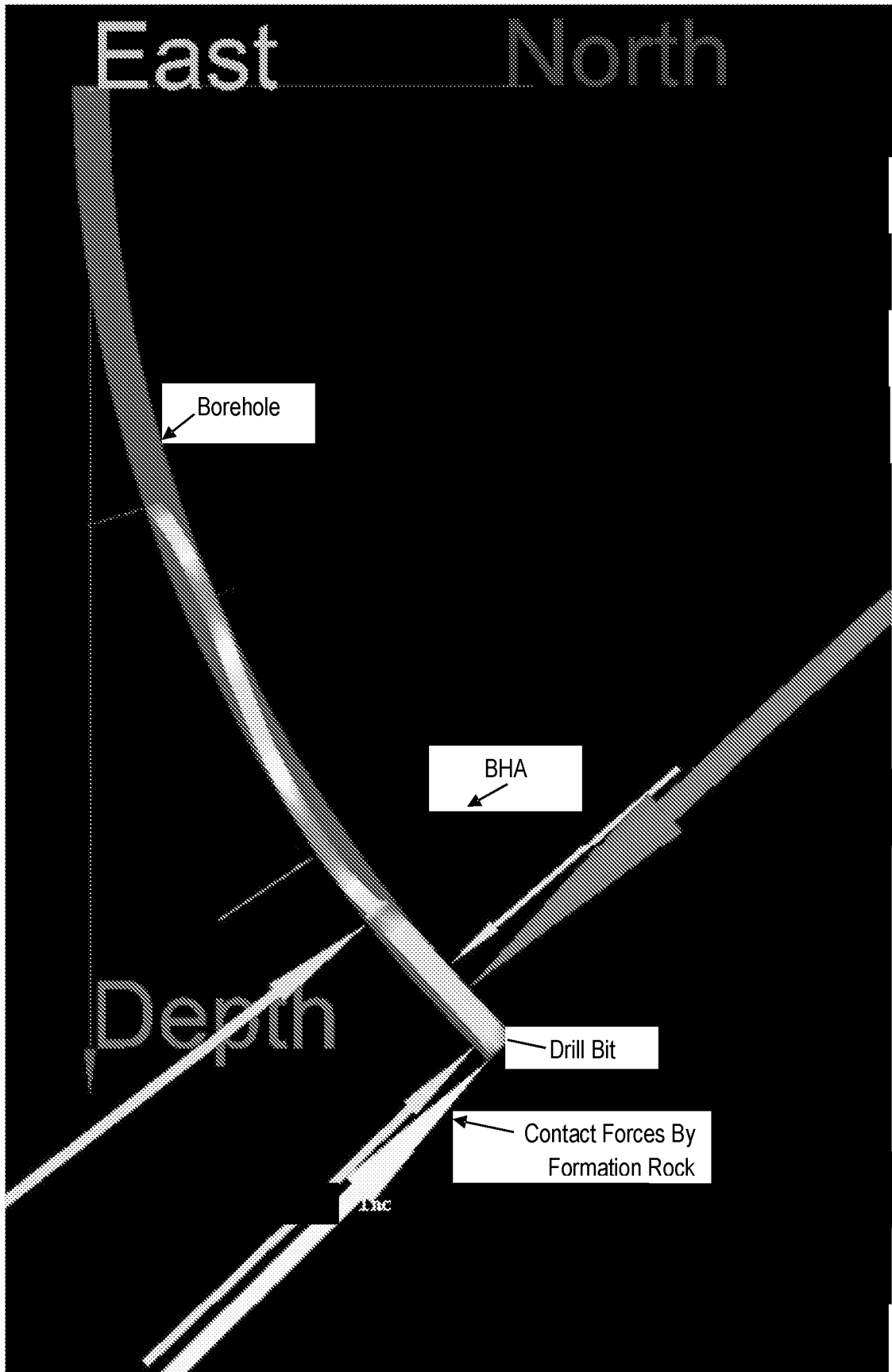


FIG. 2

3/37

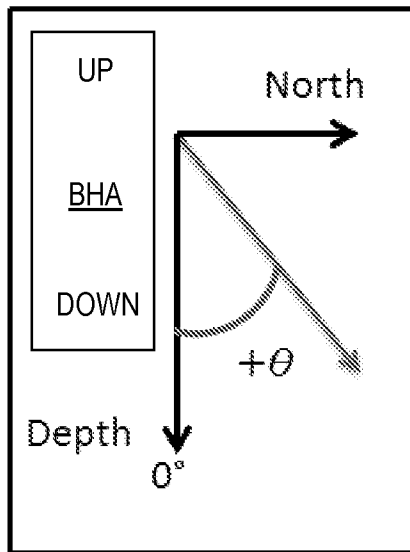


FIG. 3

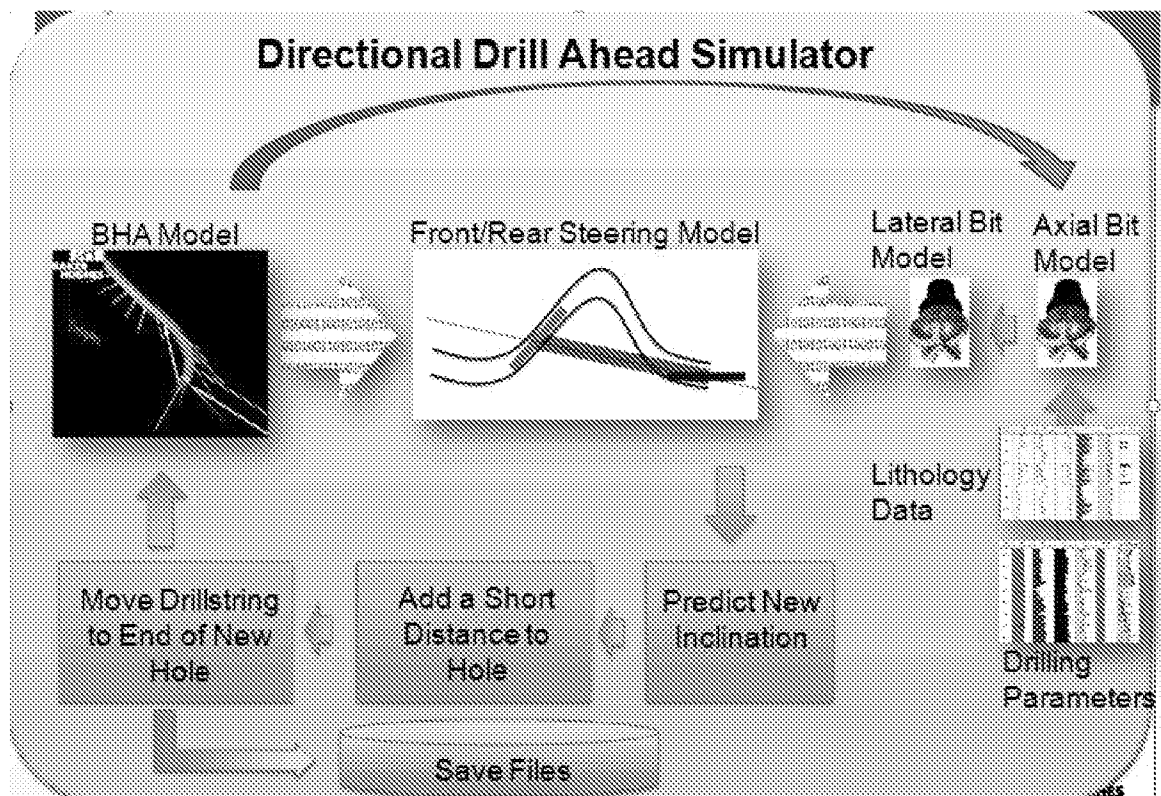
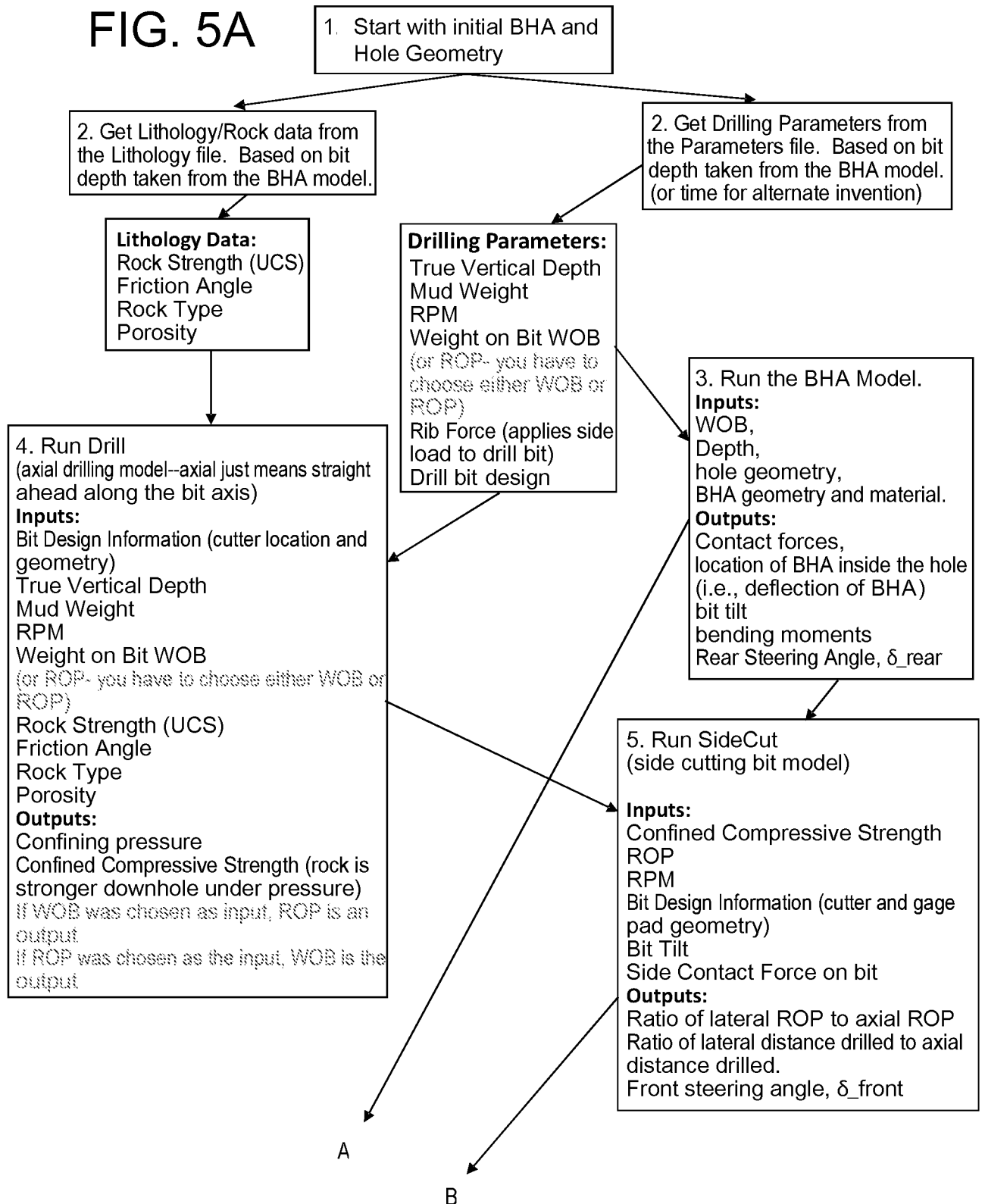


FIG. 4

4/37

FIG. 5A



5/37

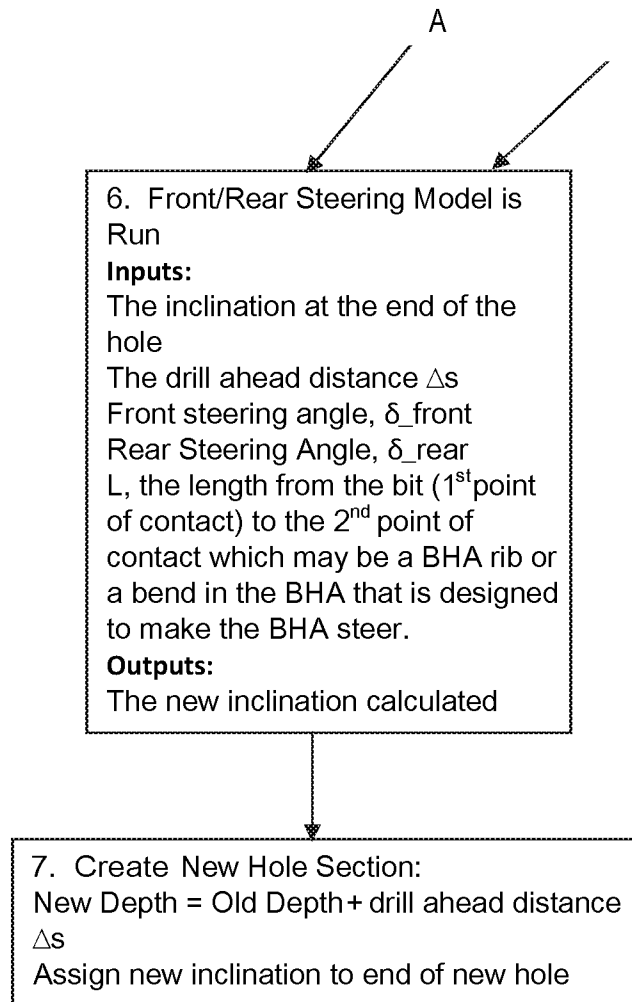


FIG. 5B

6/37

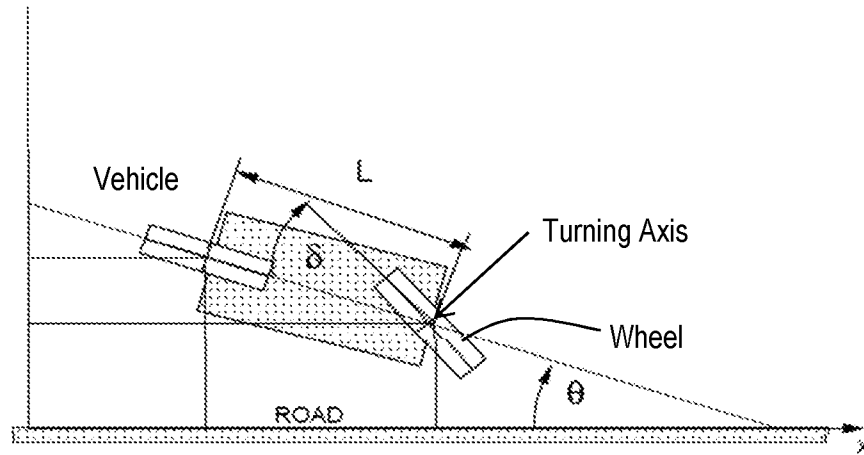


FIG. 6

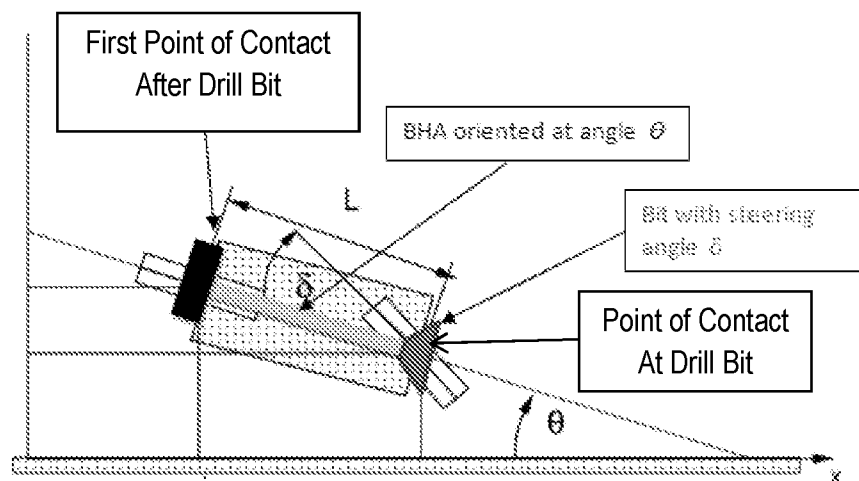


FIG. 7

7/37

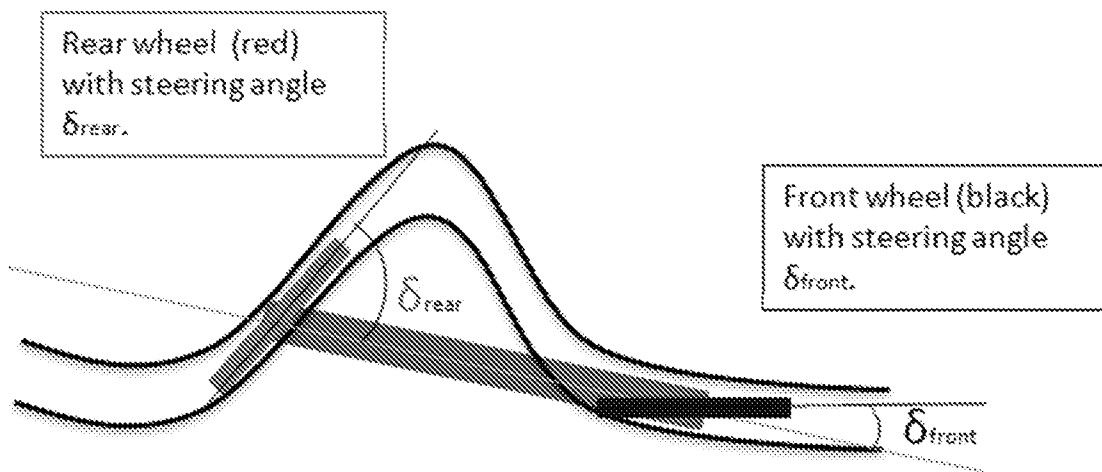


FIG. 8

8/37

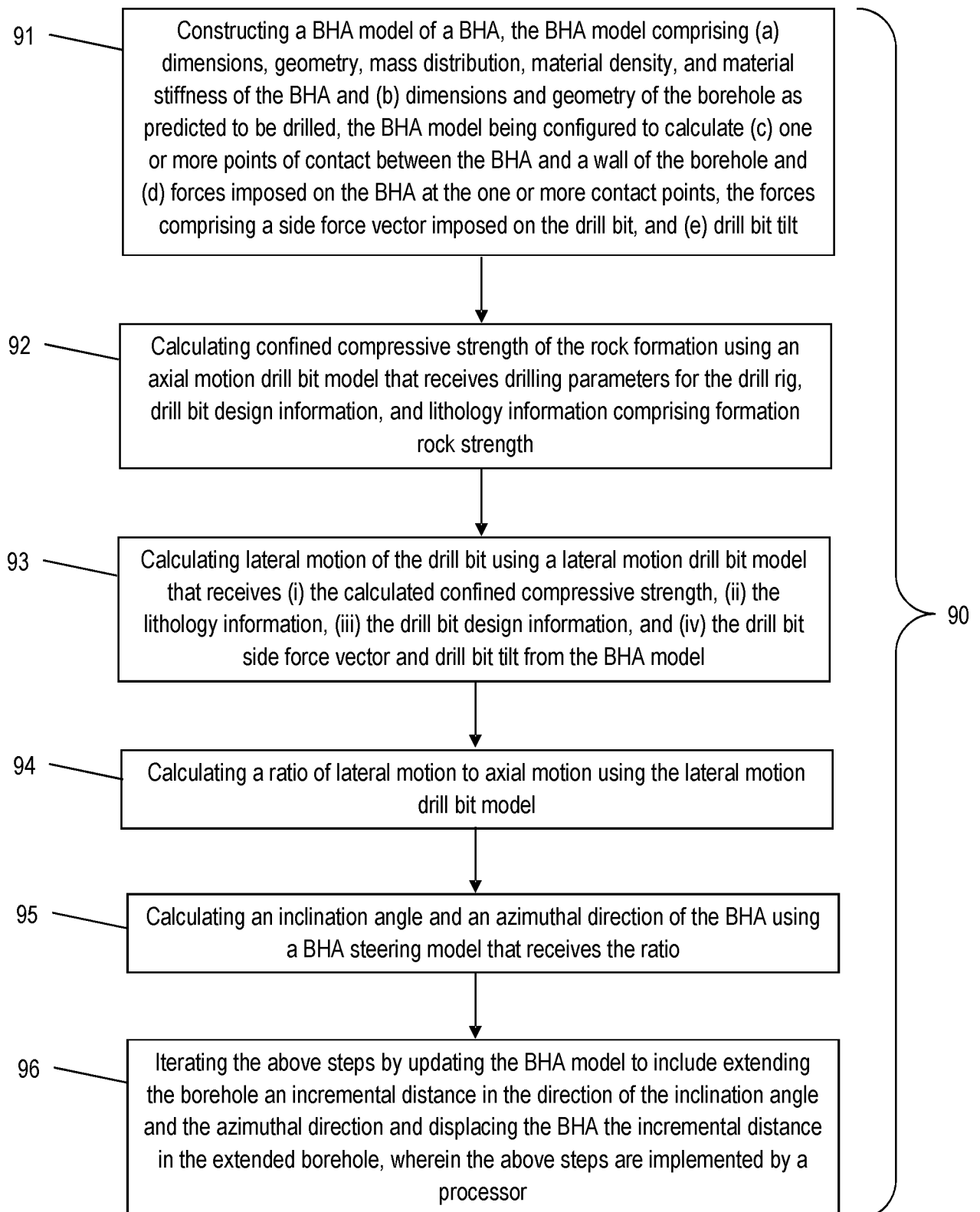
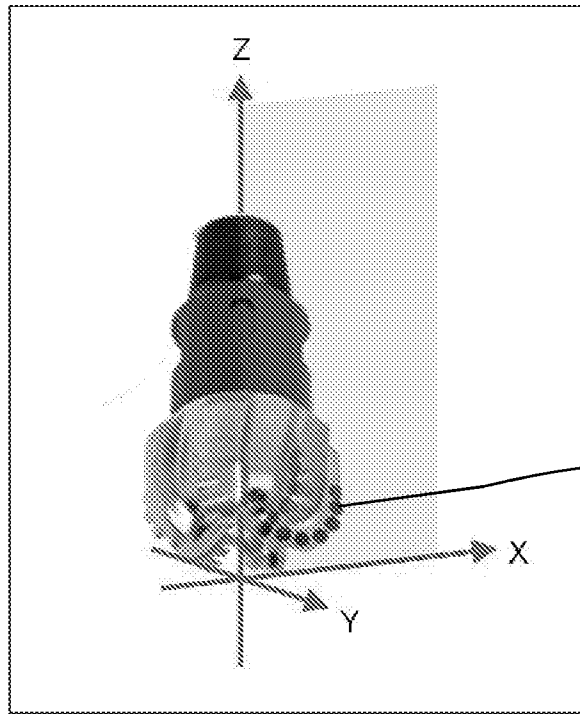


FIG. 9

9/37

Drill Bit 7



Cutter

FIG. 10

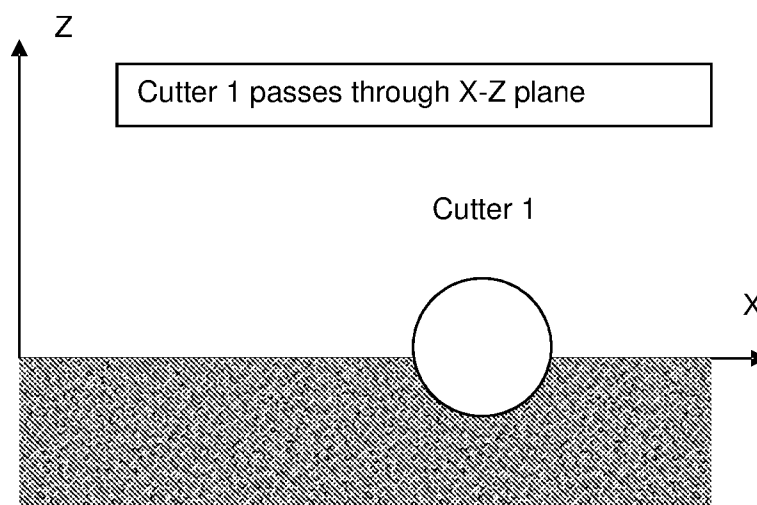
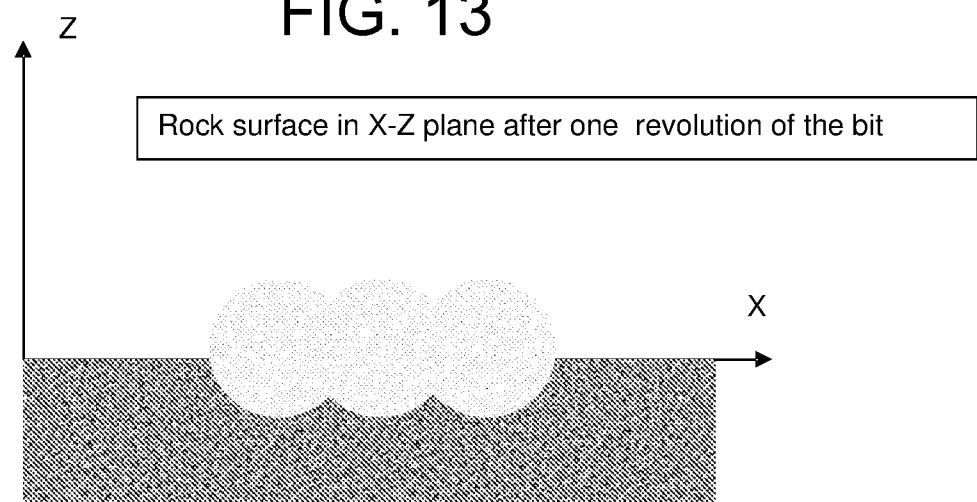
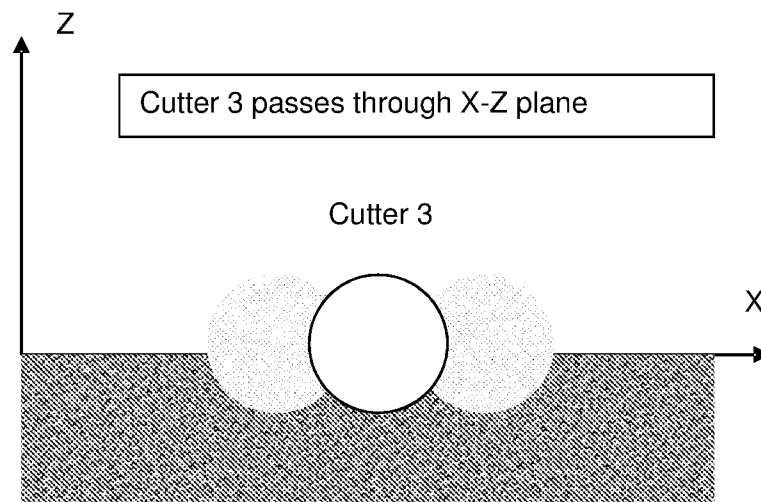
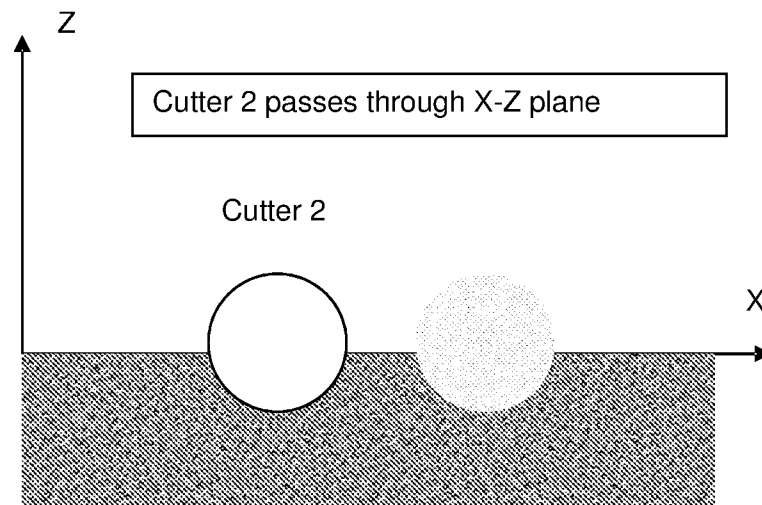


FIG. 11

10/37



11/37

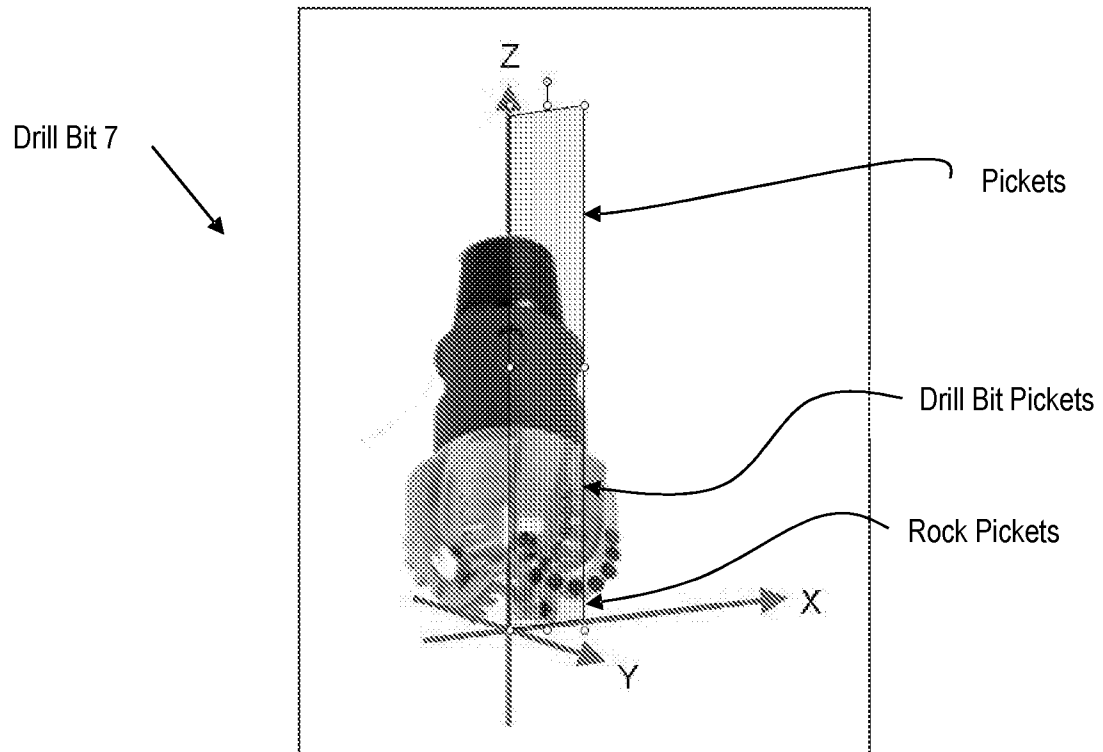


FIG. 15

12/37

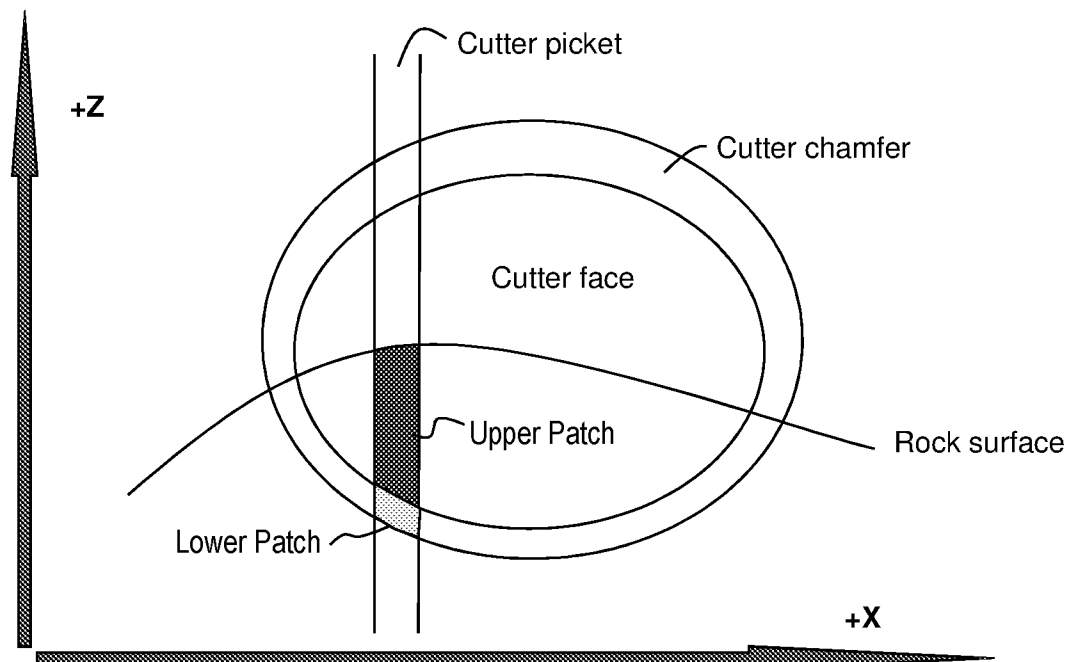


FIG. 16

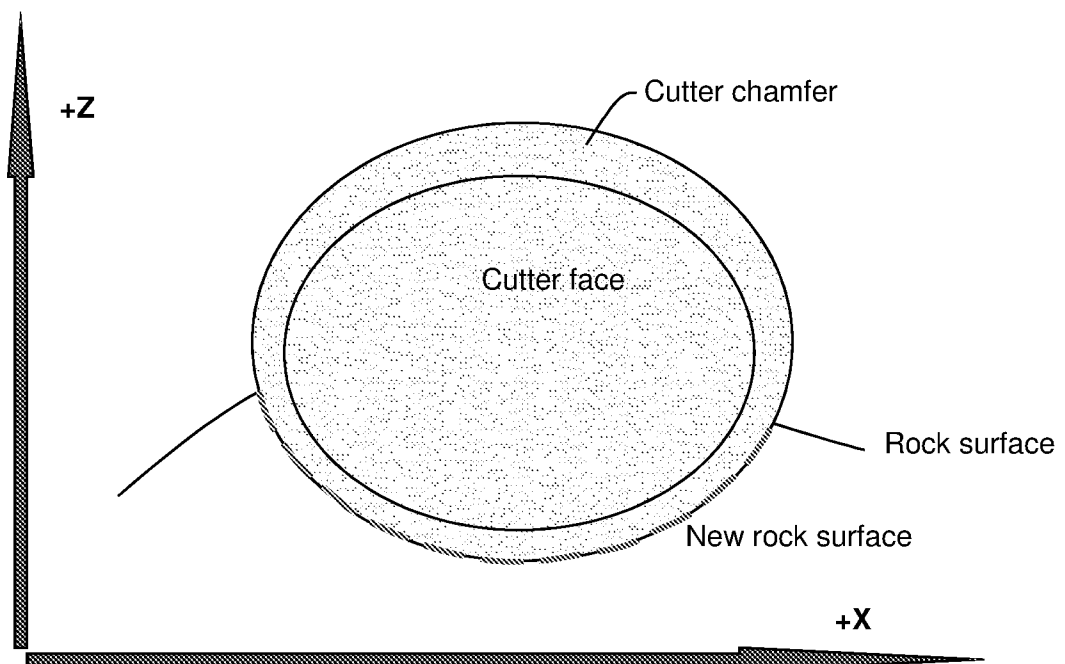


FIG. 17



FIG. 18

14/37

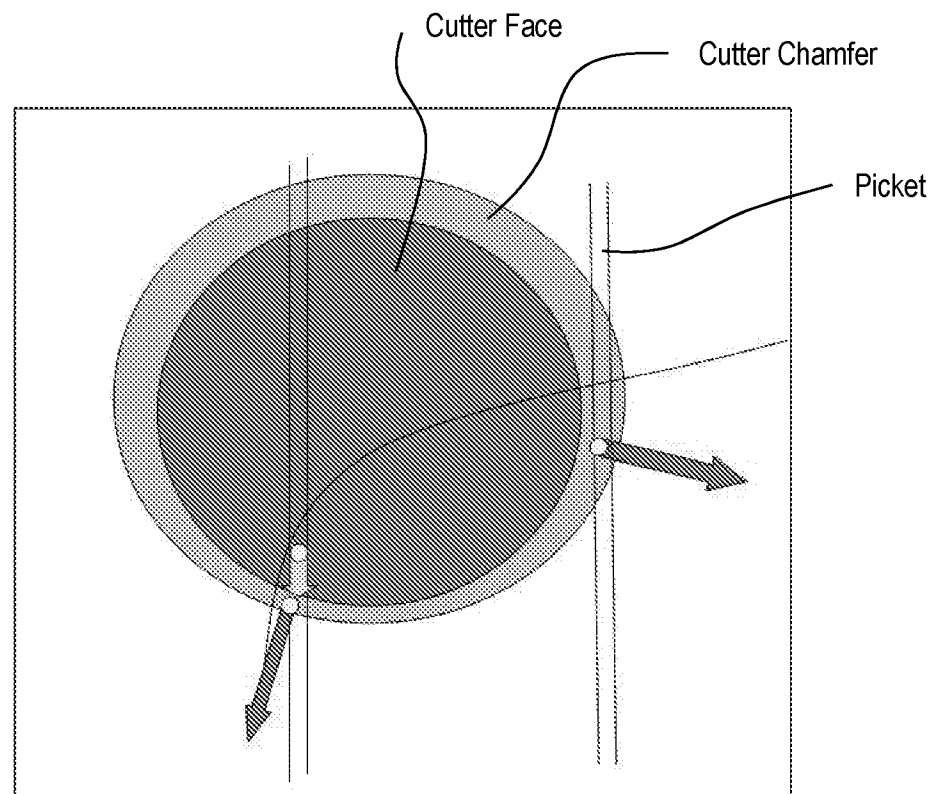


FIG. 19

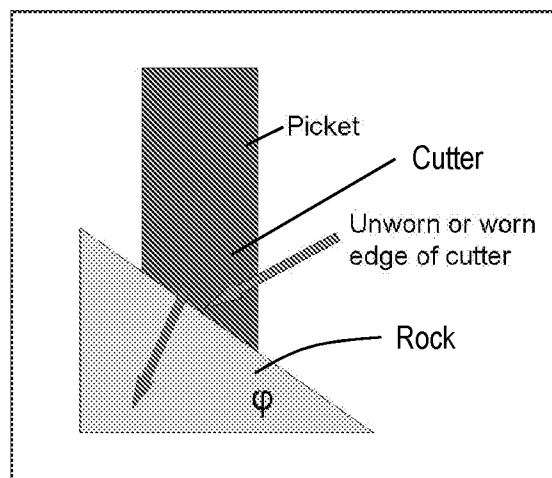


FIG. 20

15/37

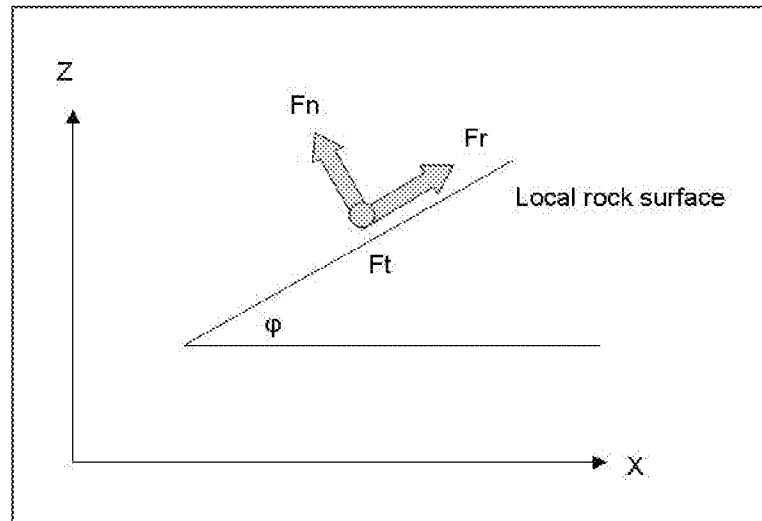


FIG. 21

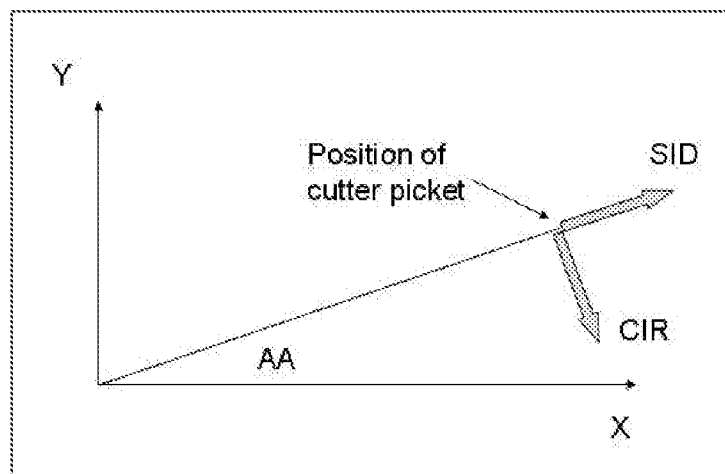


FIG. 22

16/37

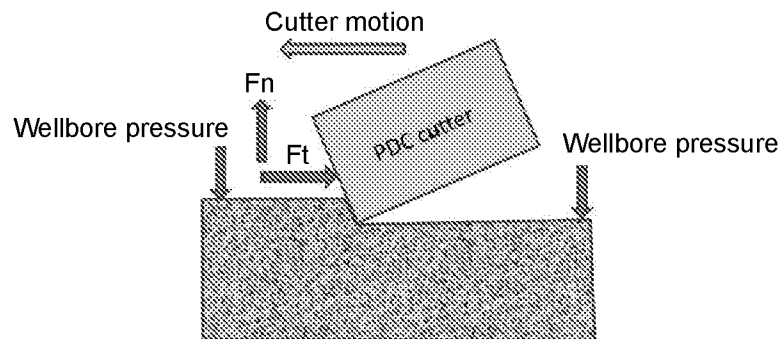


FIG. 23

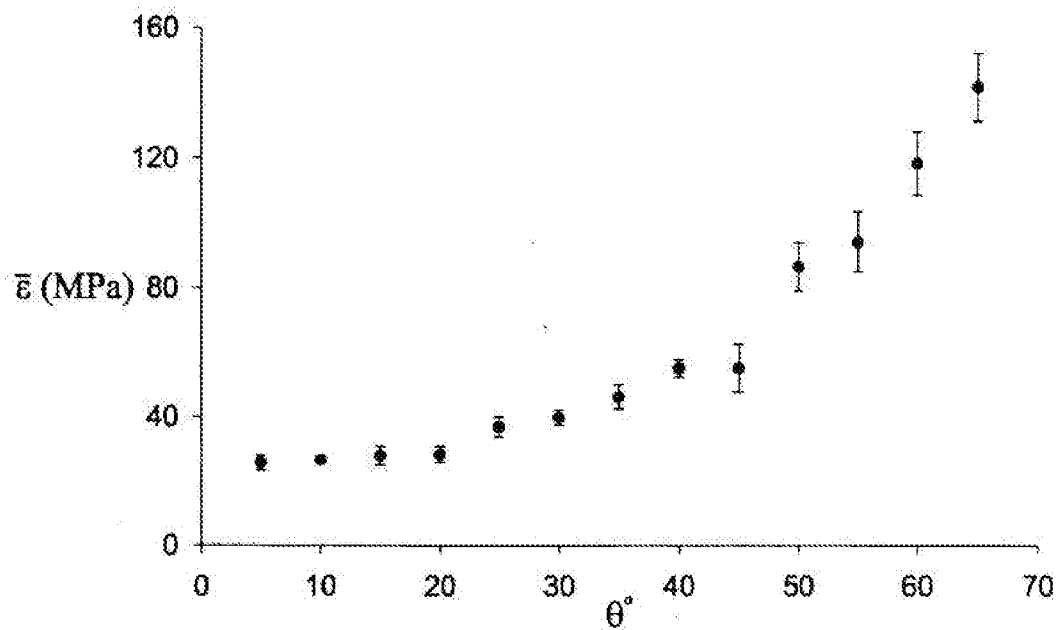


FIG. 24

+

17/37

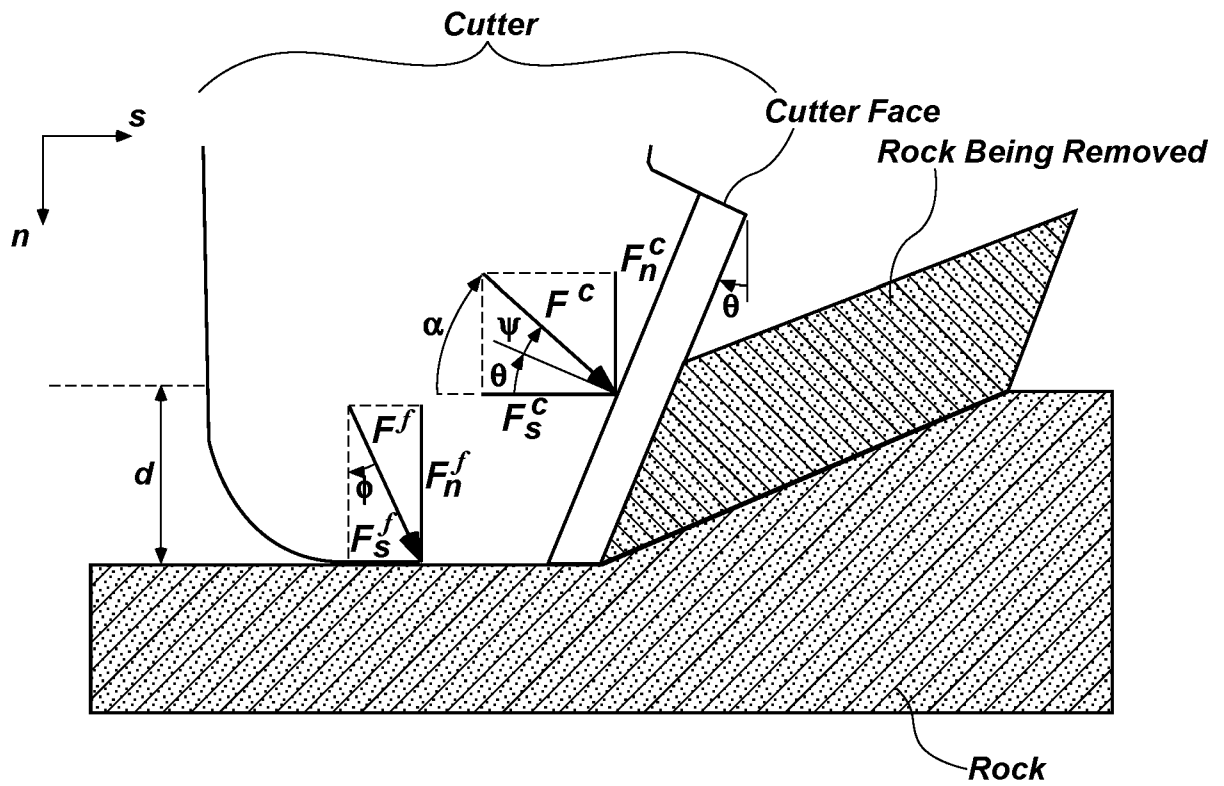


FIG. 25

+

+

18/37

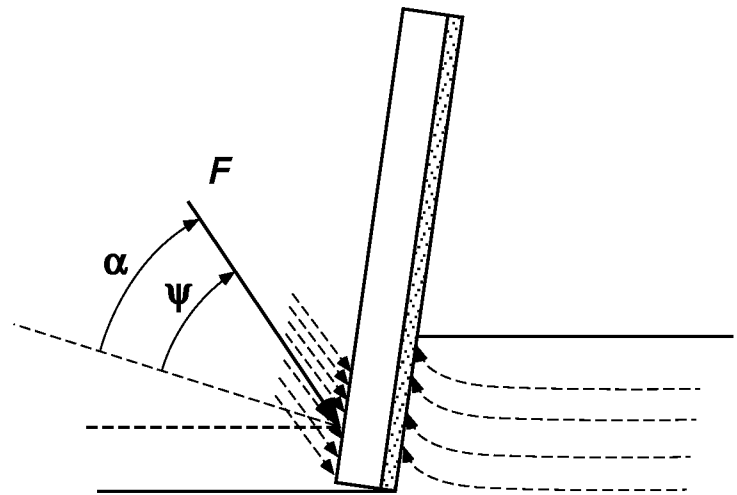


FIG. 26A

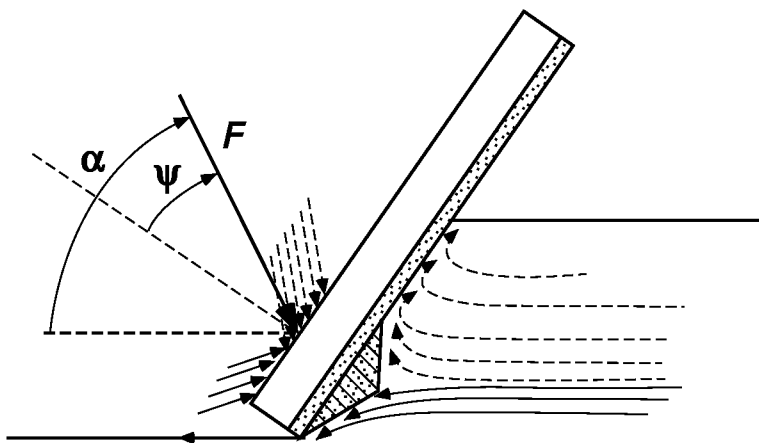


FIG. 26B

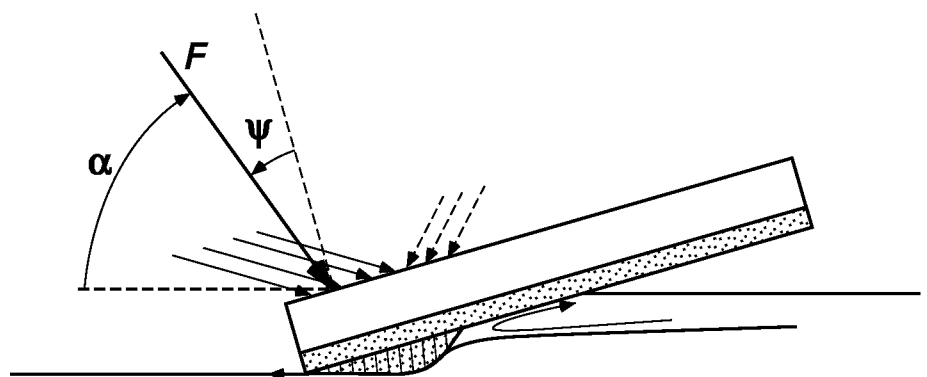


FIG. 26C

+

19/37

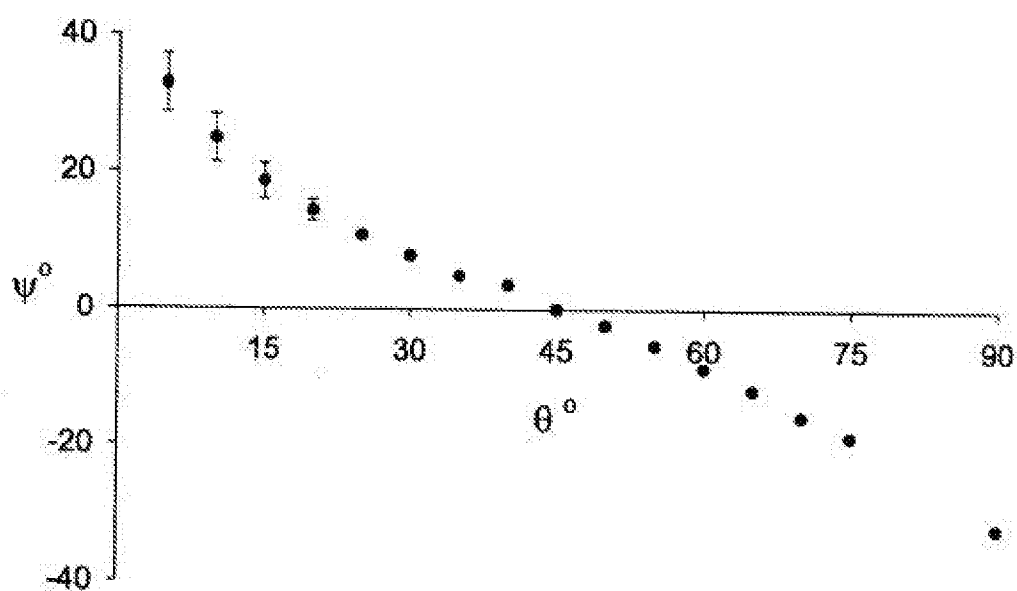


FIG. 27

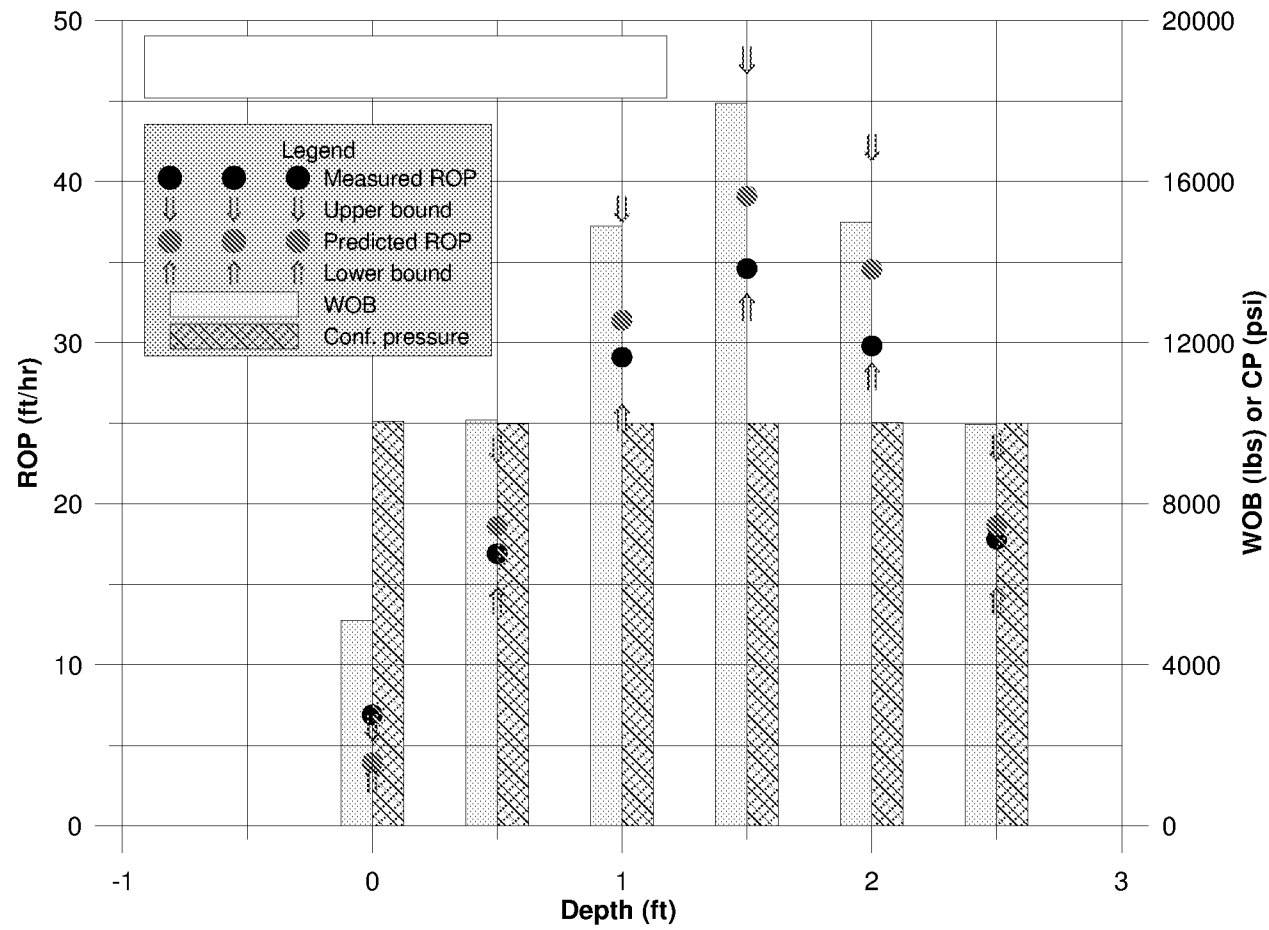


FIG. 28

21/37

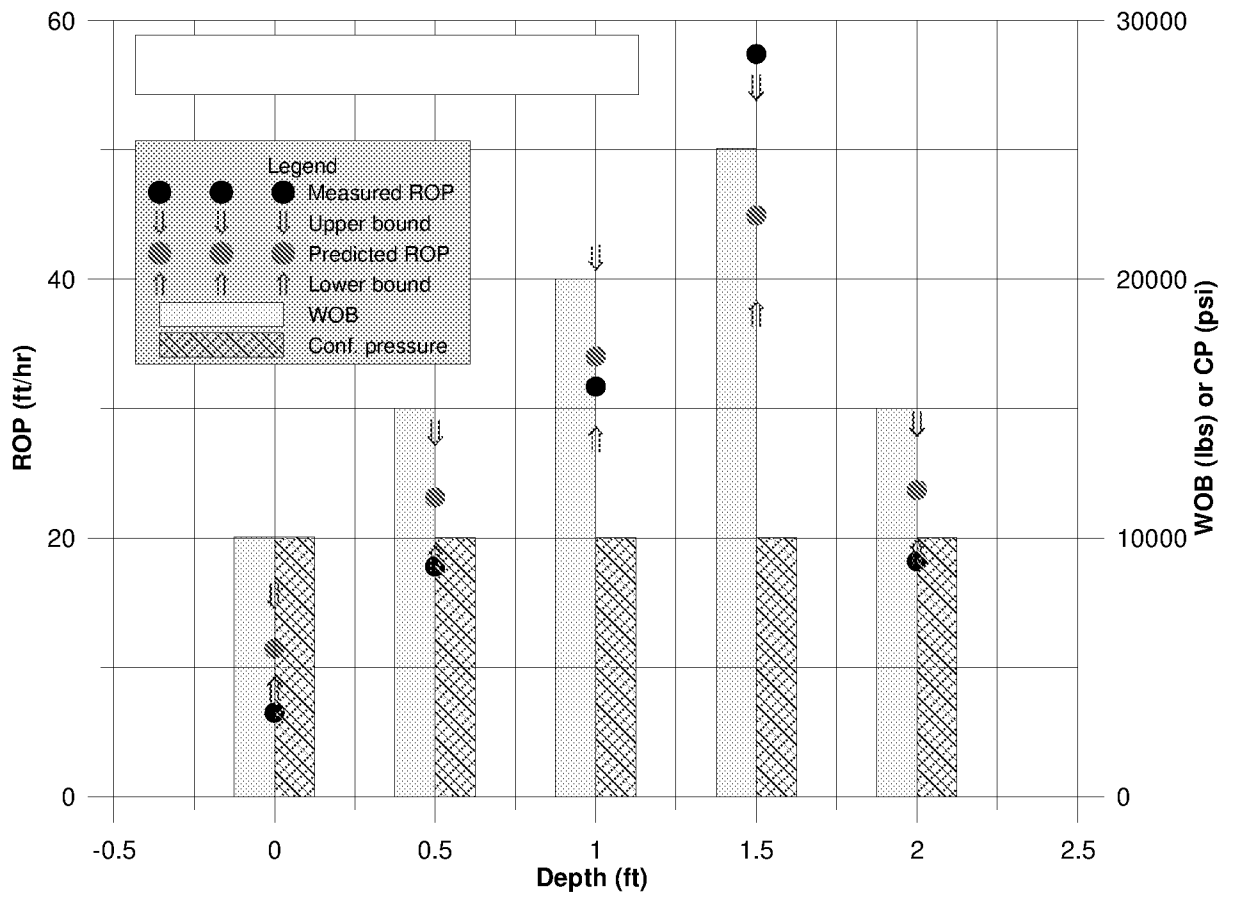


FIG. 29

22/37

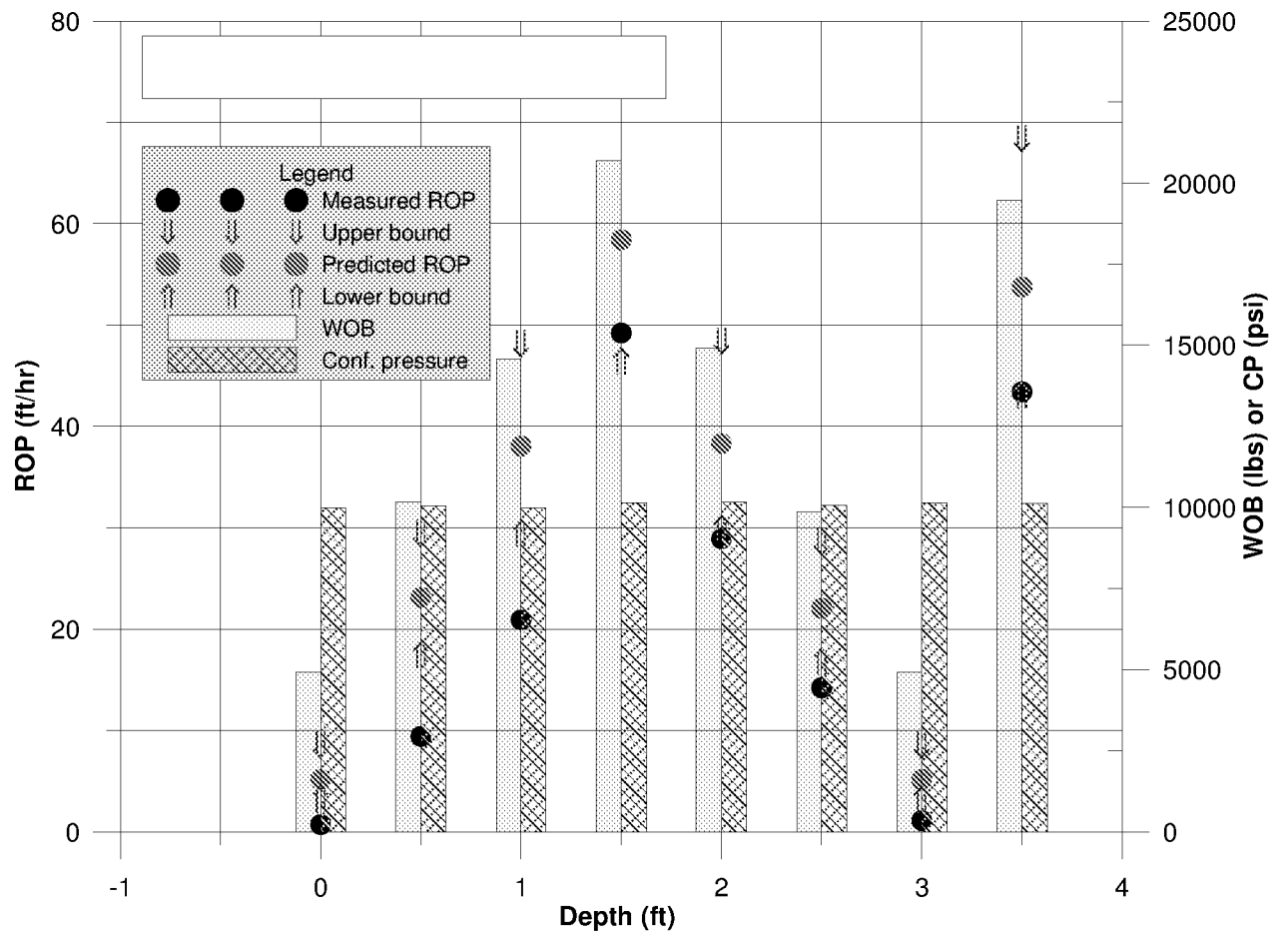


FIG. 30

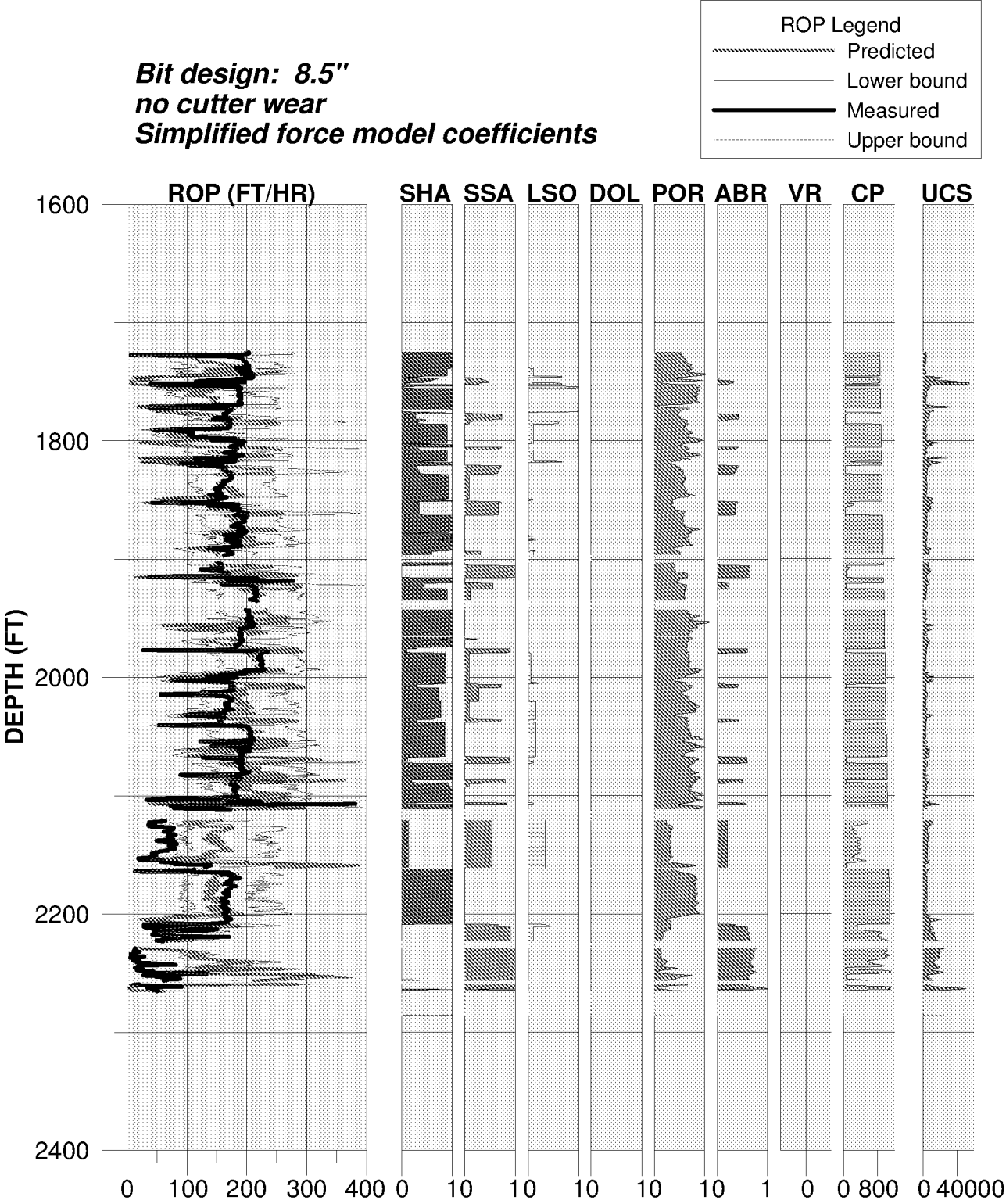


FIG. 31

24/37

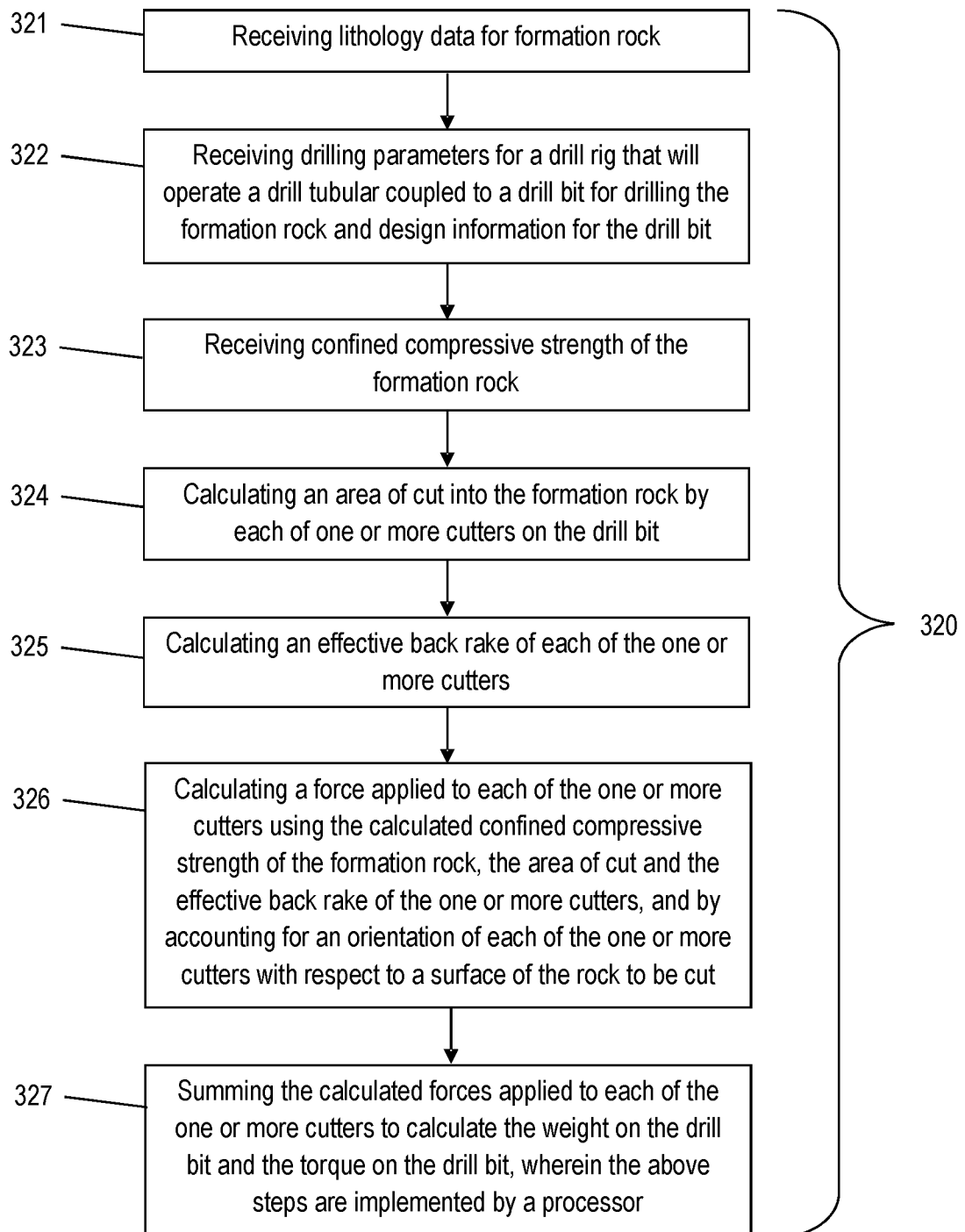


FIG. 32

25/37

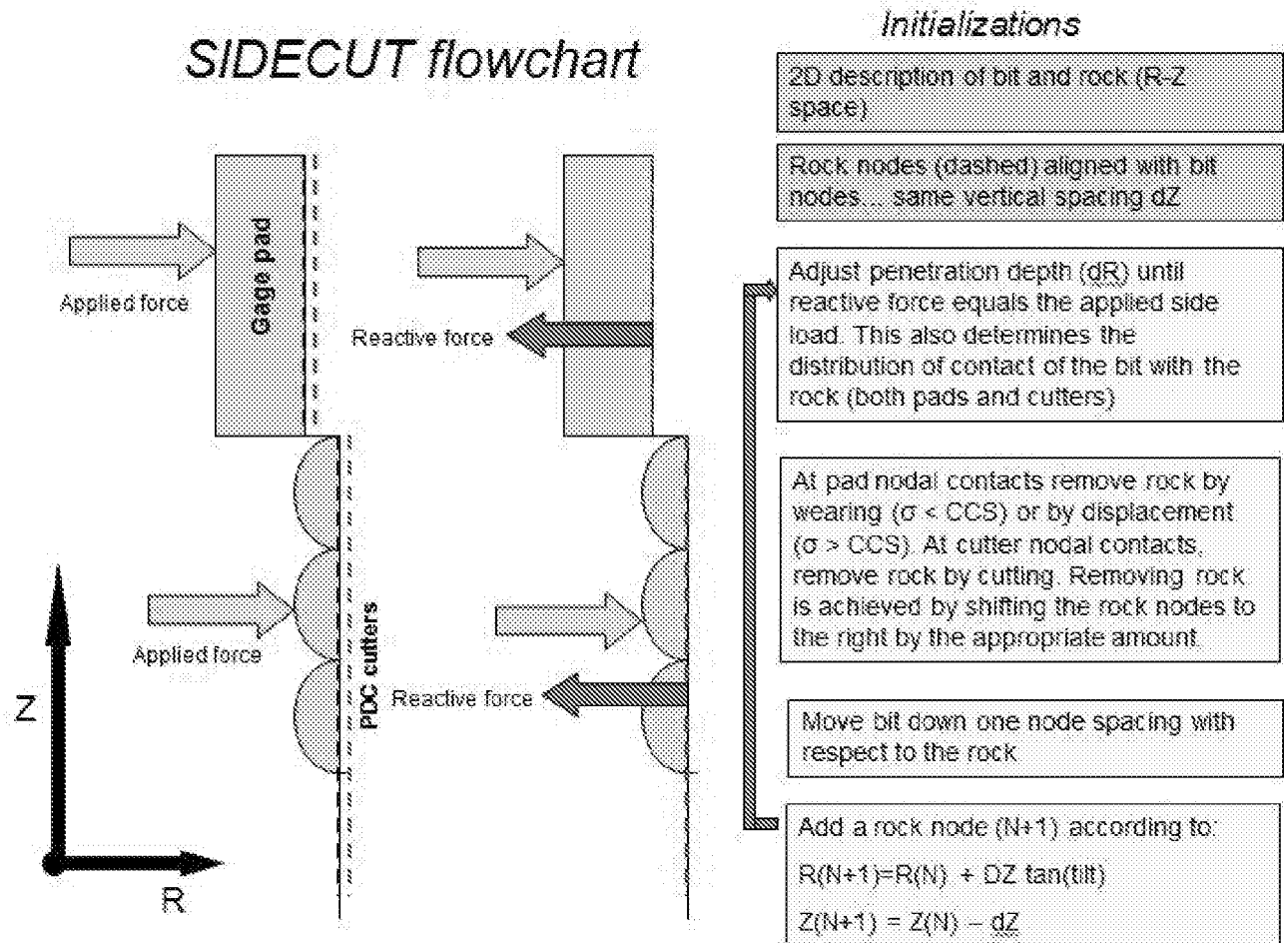


FIG. 33

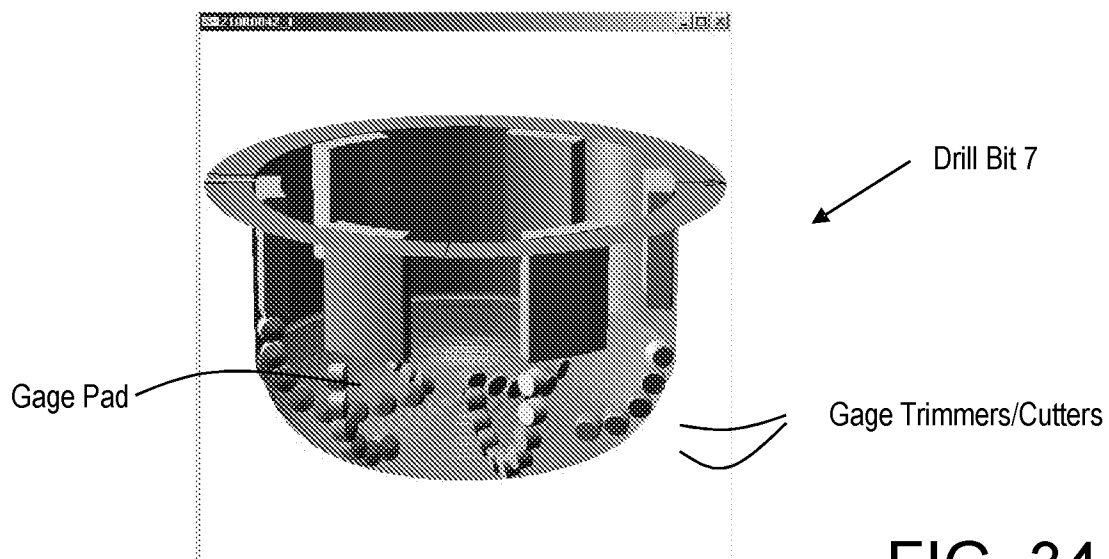


FIG. 34

26/37

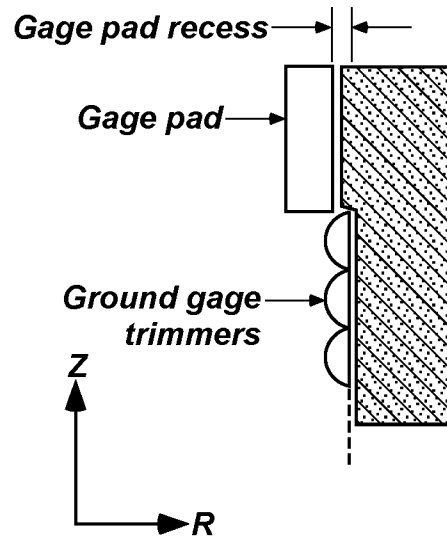


FIG. 35

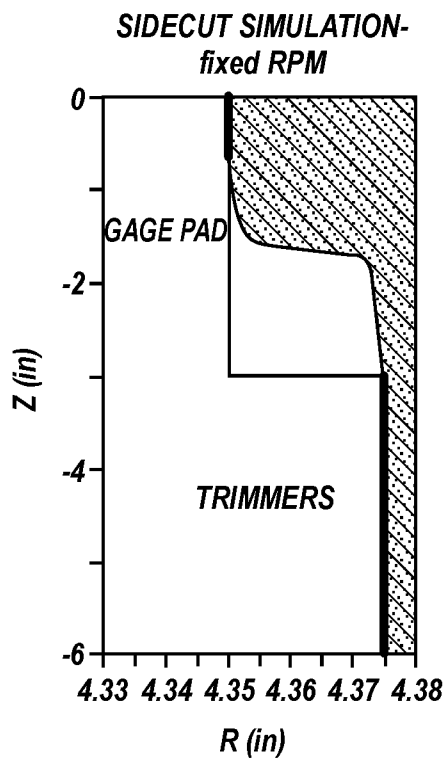


FIG. 36

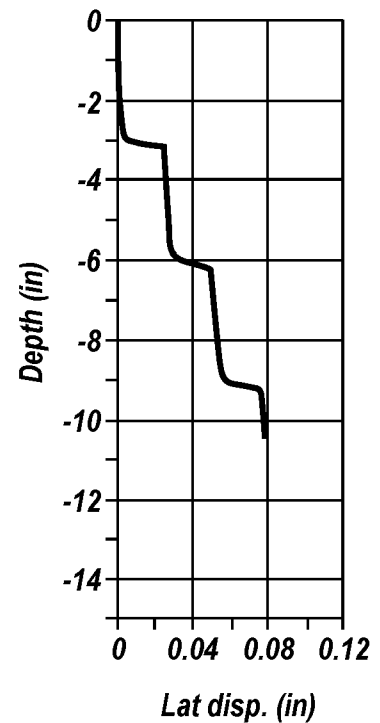


FIG. 37

27/37

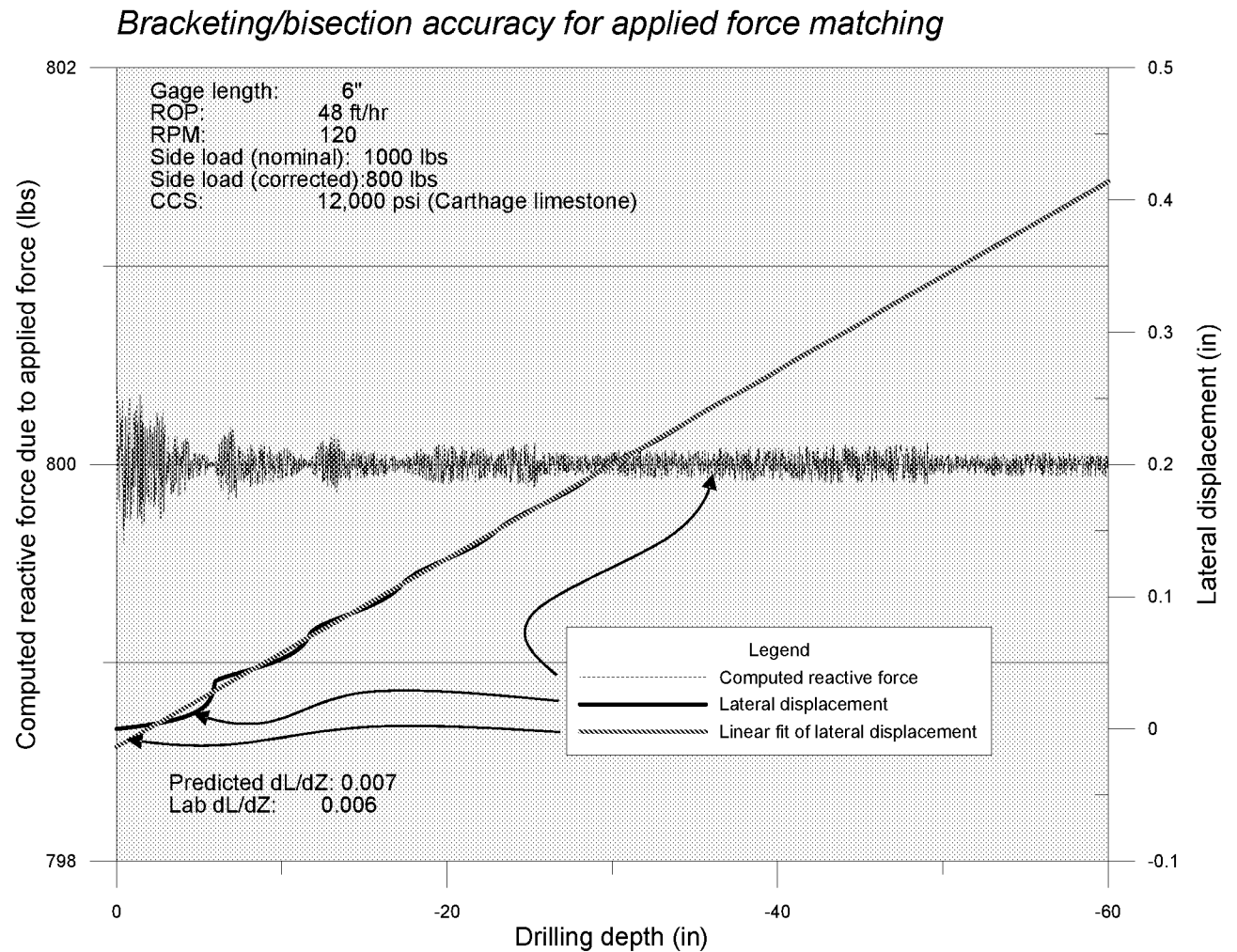


FIG. 38

28/37

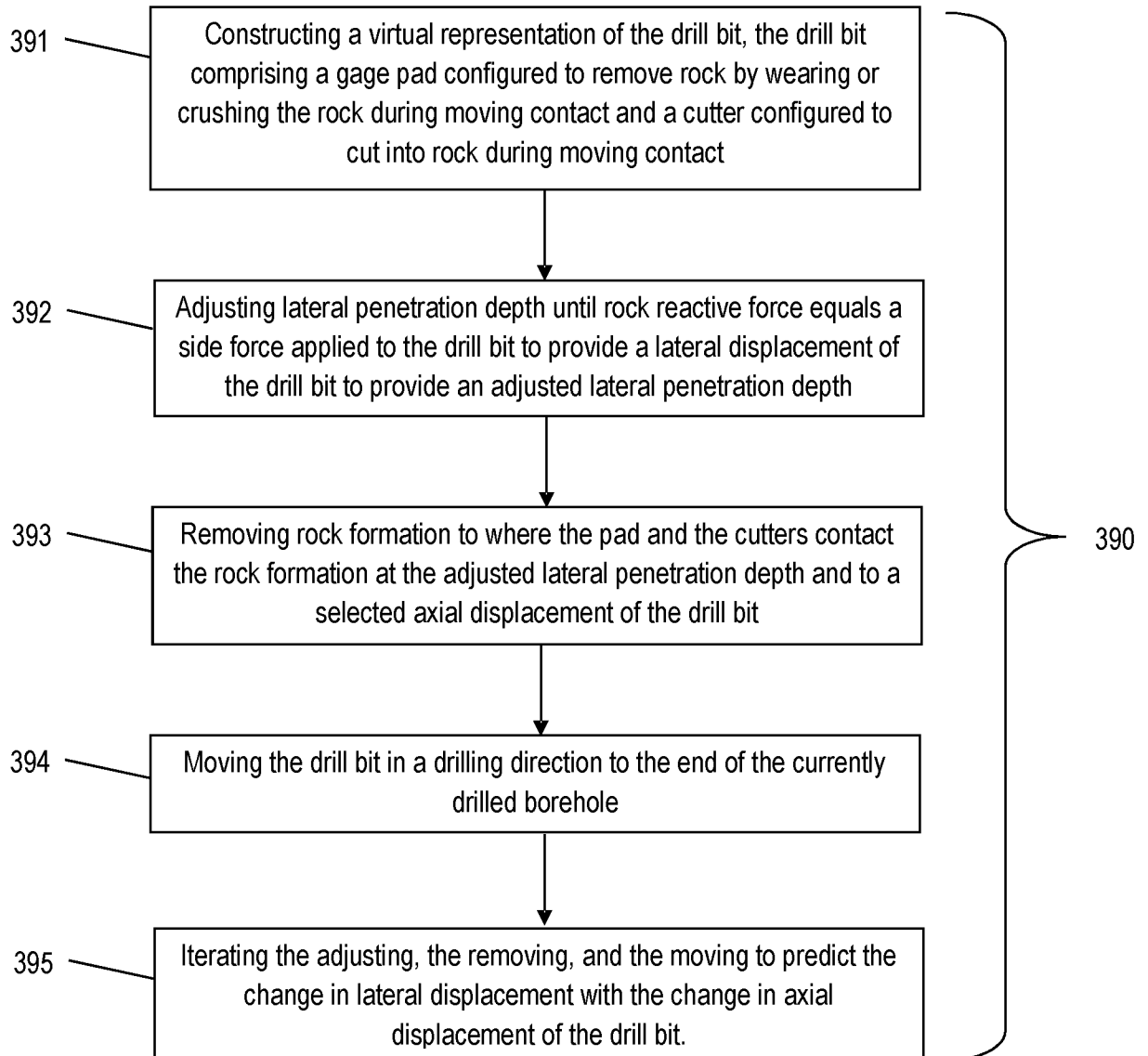


FIG. 39

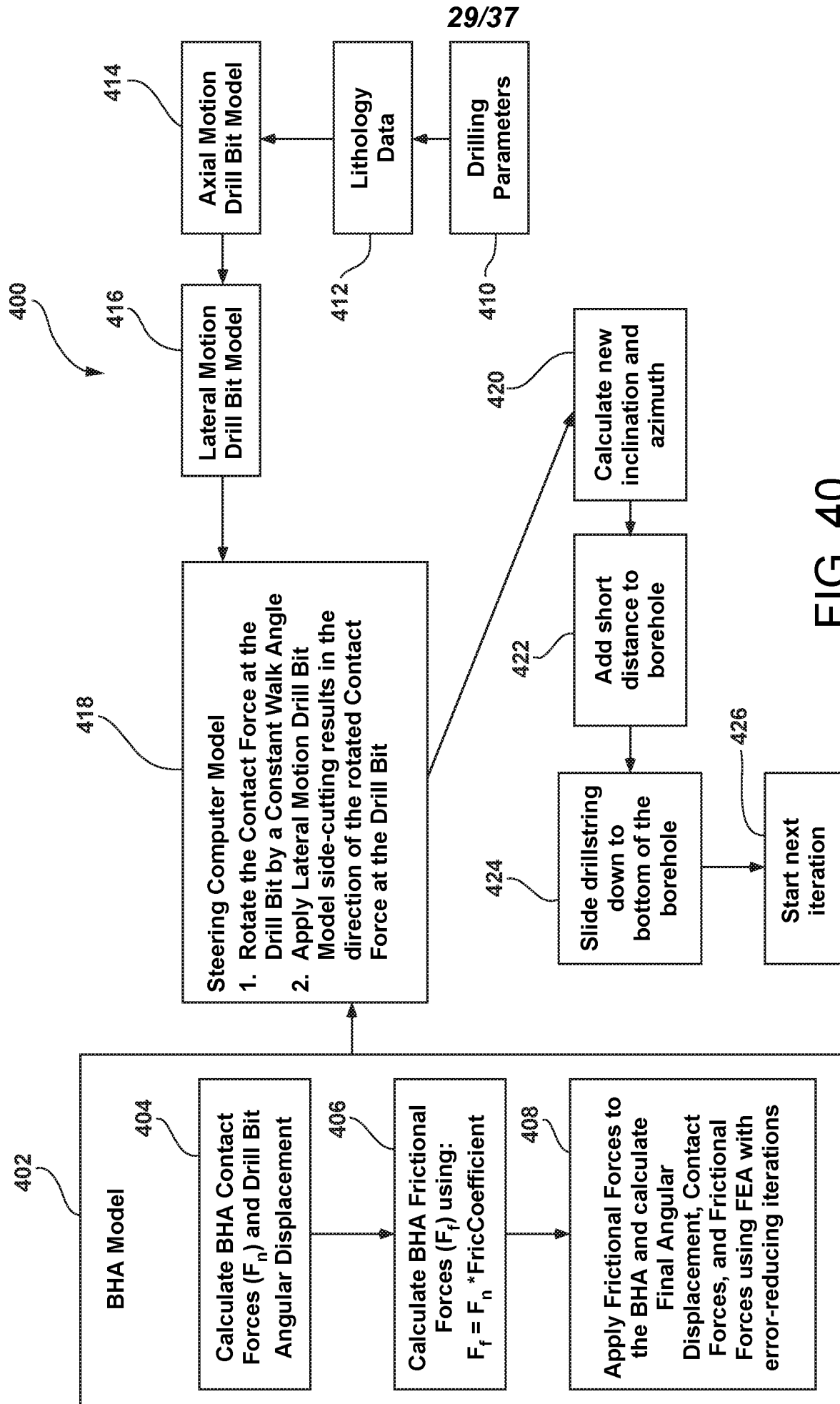


FIG. 40

30/37

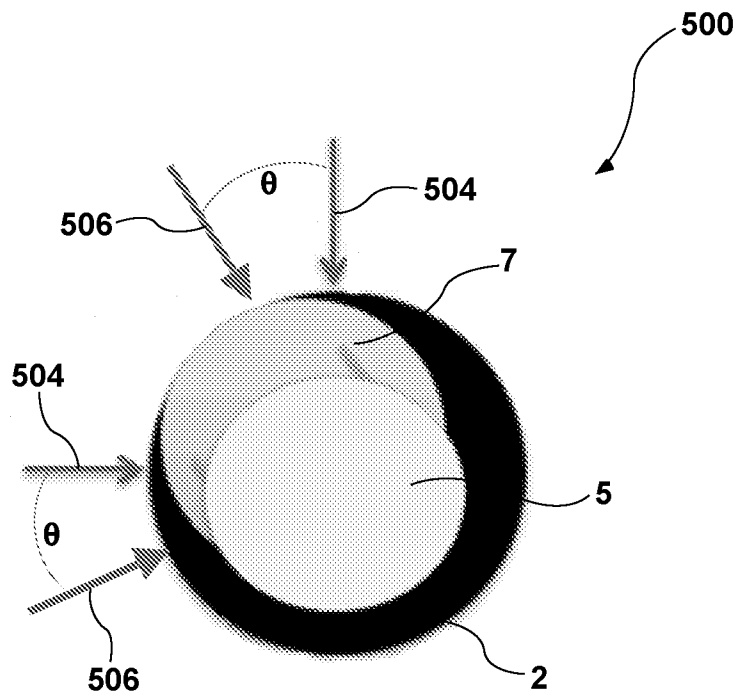


FIG. 41

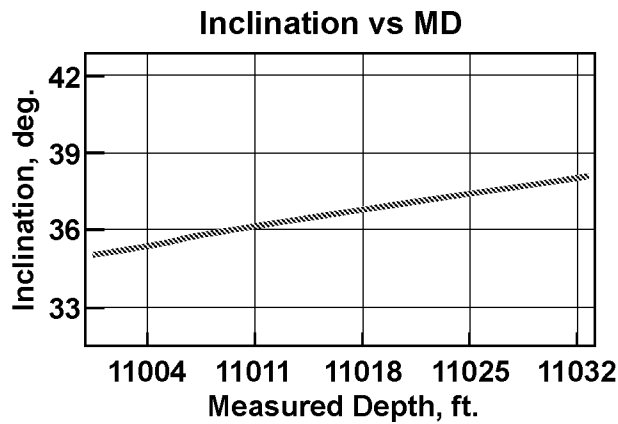


FIG. 42A

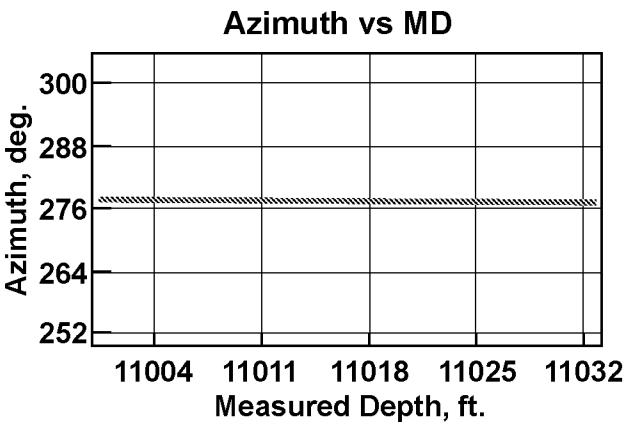


FIG. 42B

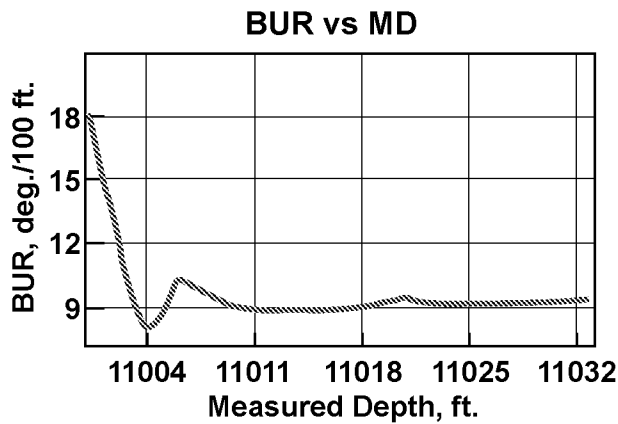


FIG. 42C

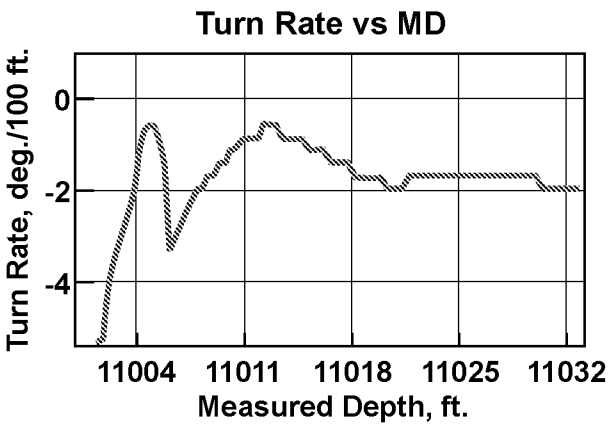


FIG. 42D

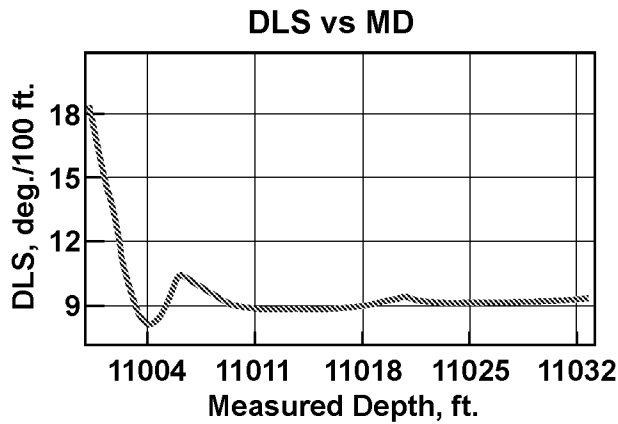


FIG. 42E

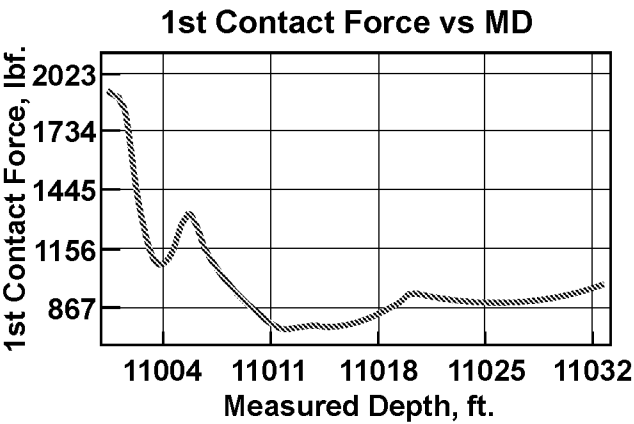


FIG. 42F

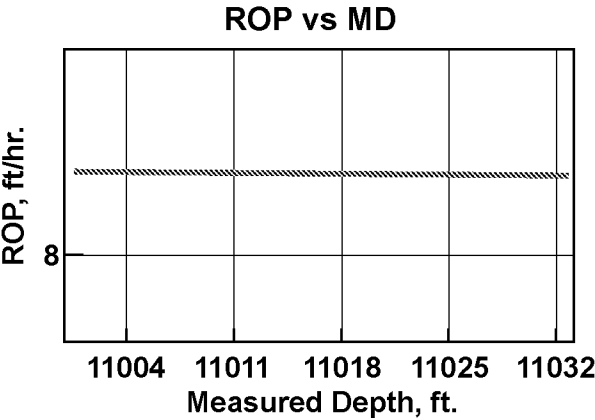


FIG. 42G

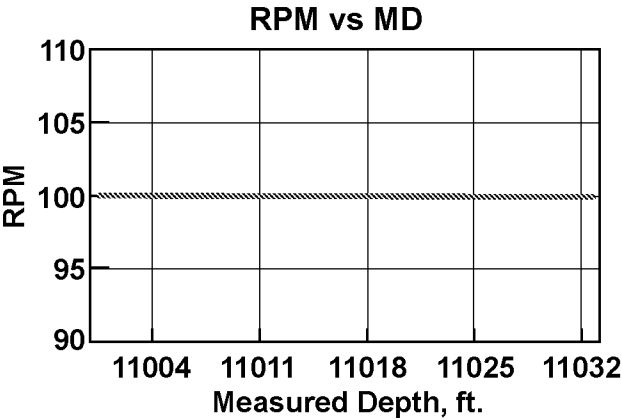


FIG. 42H

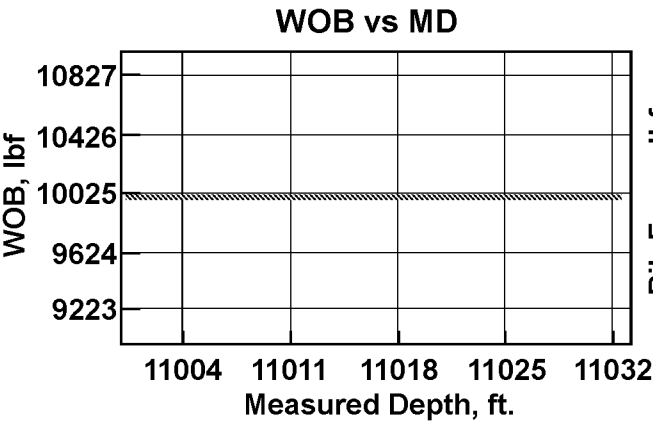


FIG. 42I

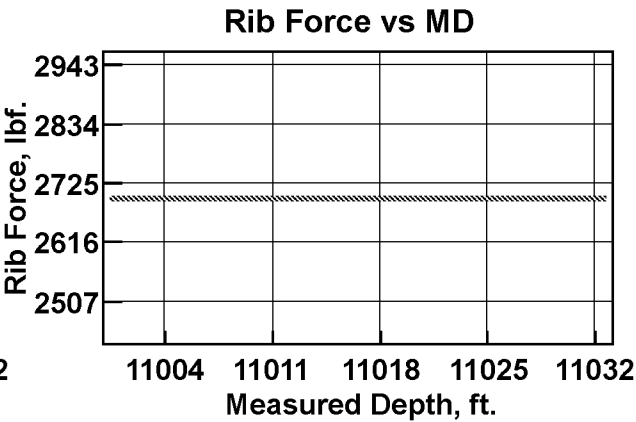


FIG. 42J

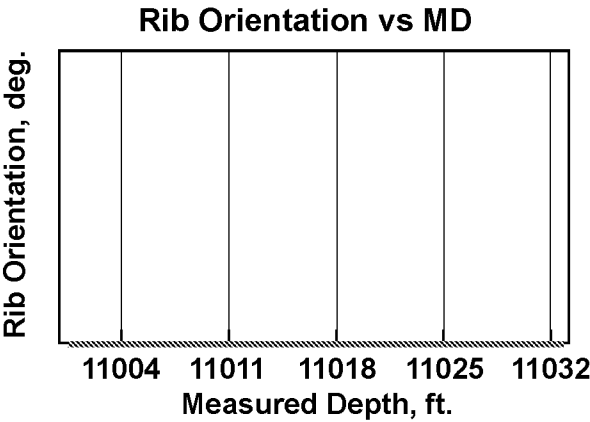


FIG. 42K

33/37

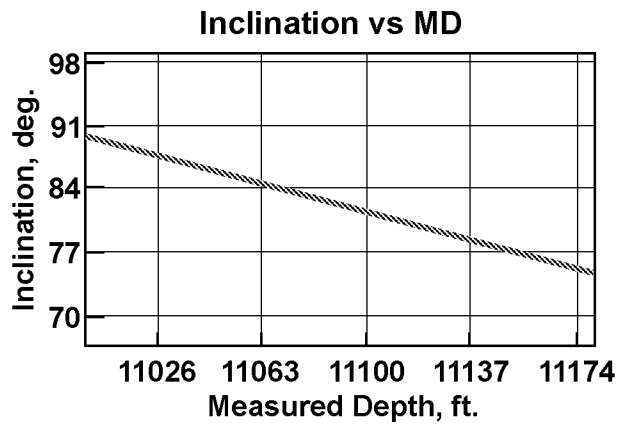


FIG. 43A

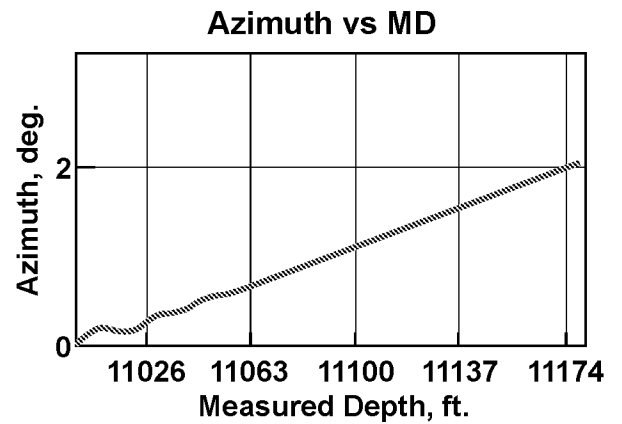


FIG. 43B

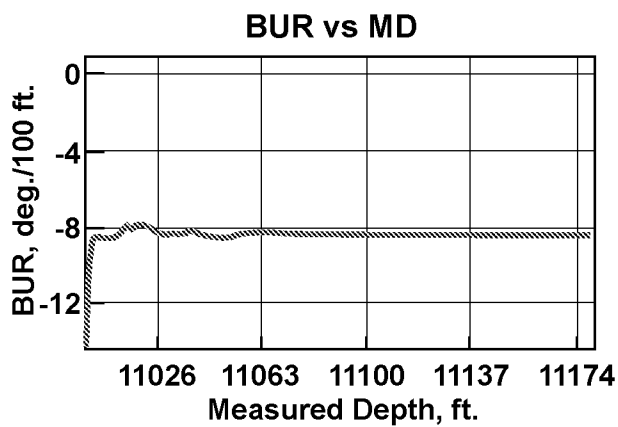


FIG. 43C

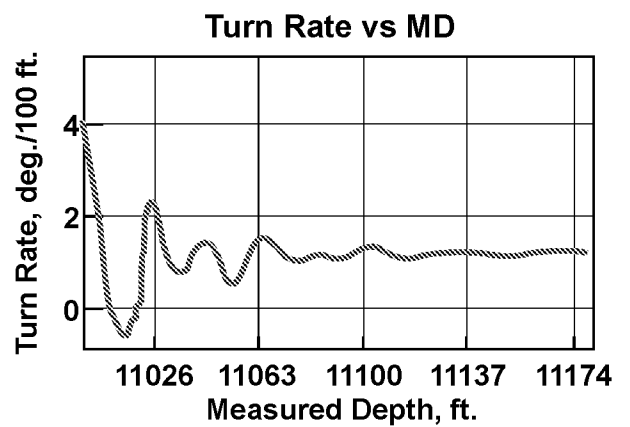


FIG. 43D

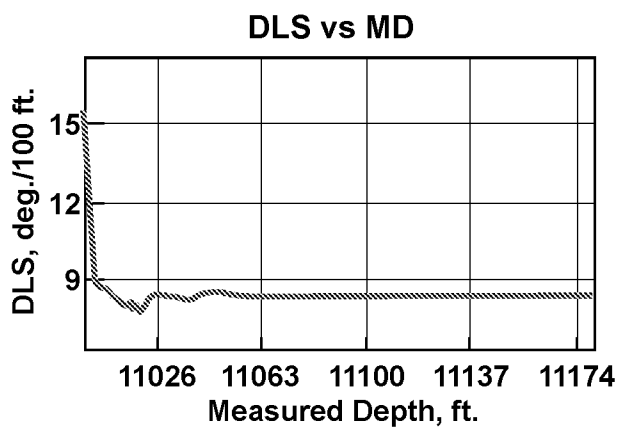


FIG. 43E

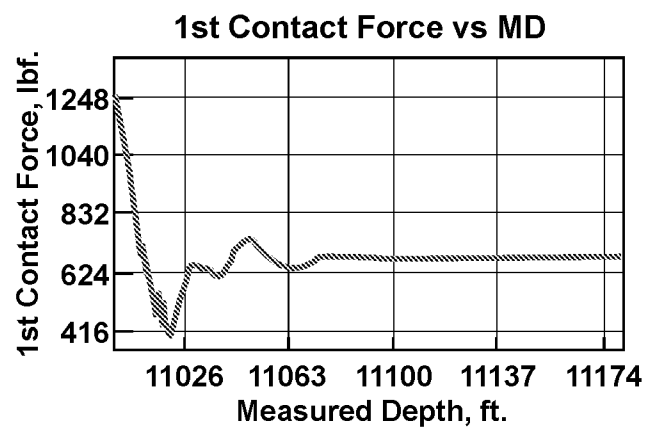


FIG. 43F

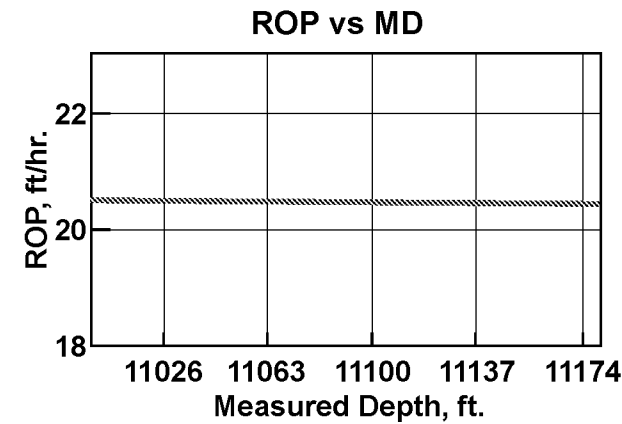


FIG. 43G

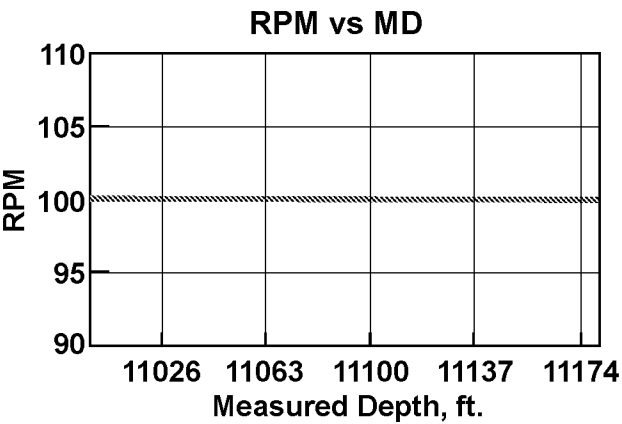


FIG. 43H

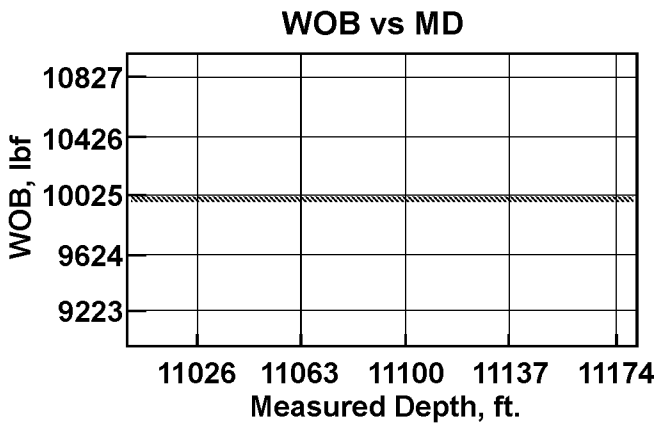


FIG. 43I

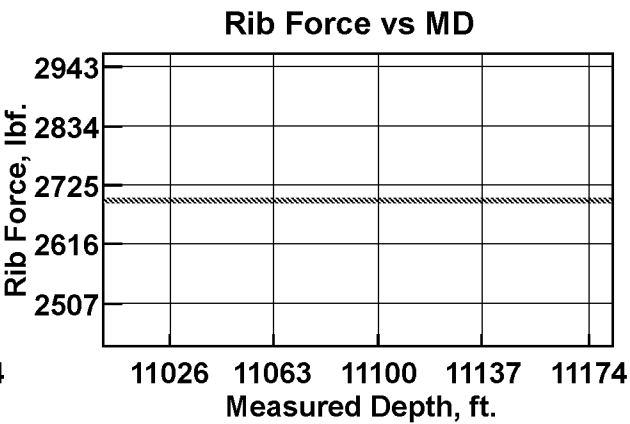


FIG. 43J

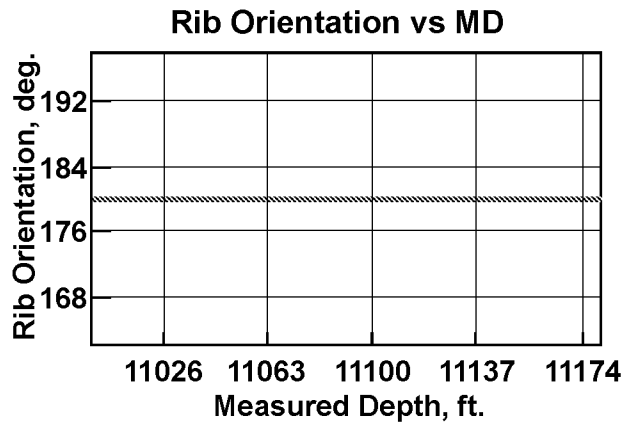


FIG. 43K

35/37

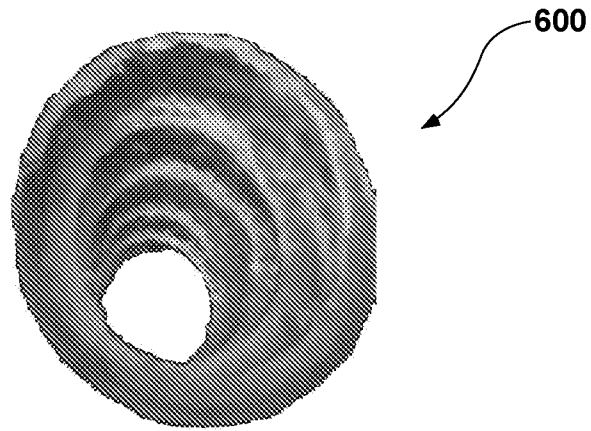


FIG. 44A

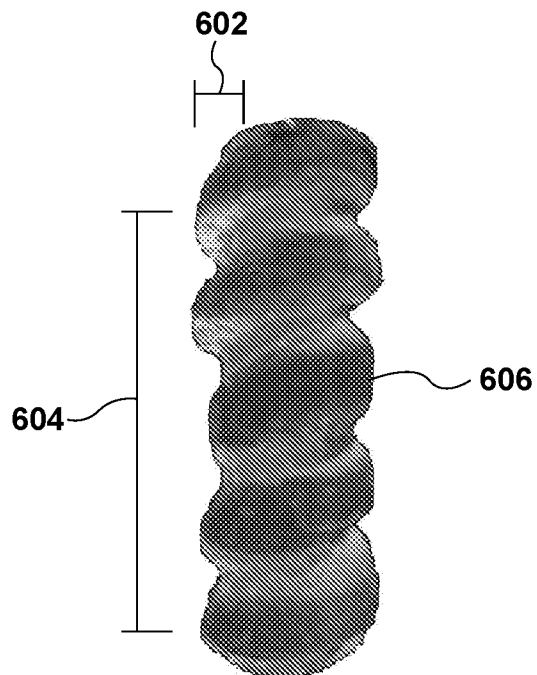


FIG. 44B

36/37

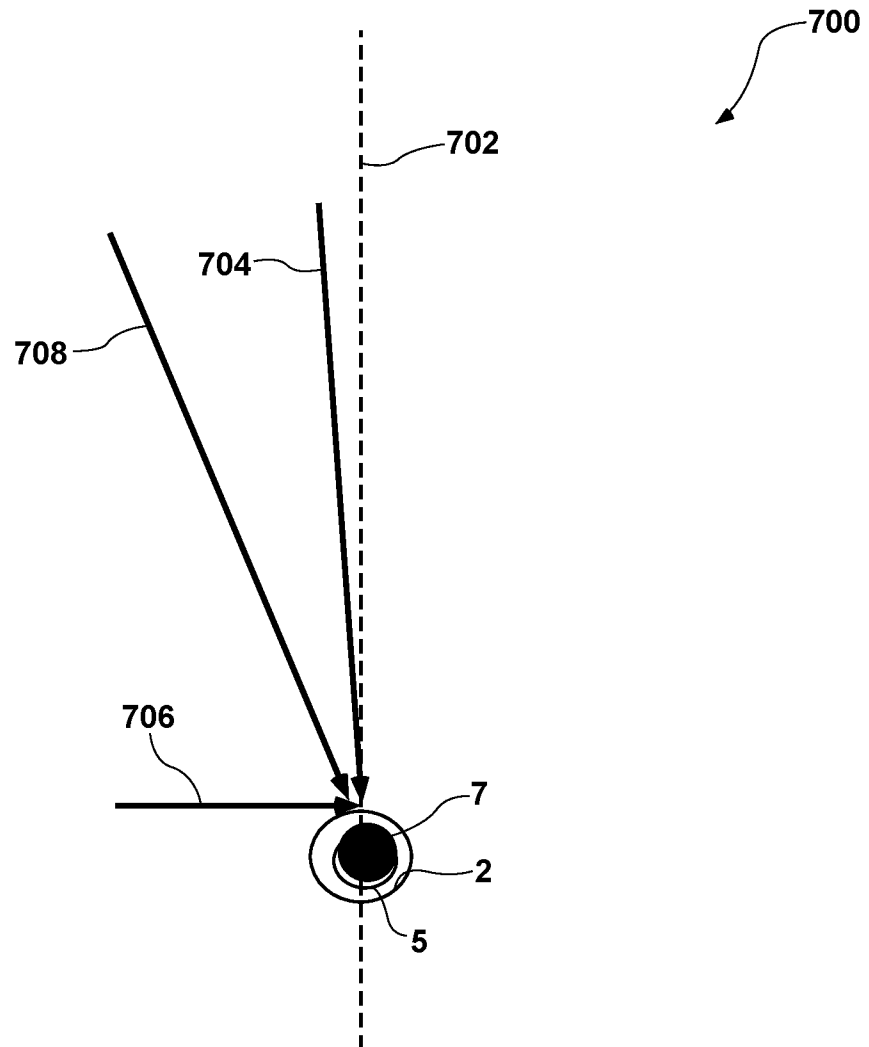


FIG. 45

37/37

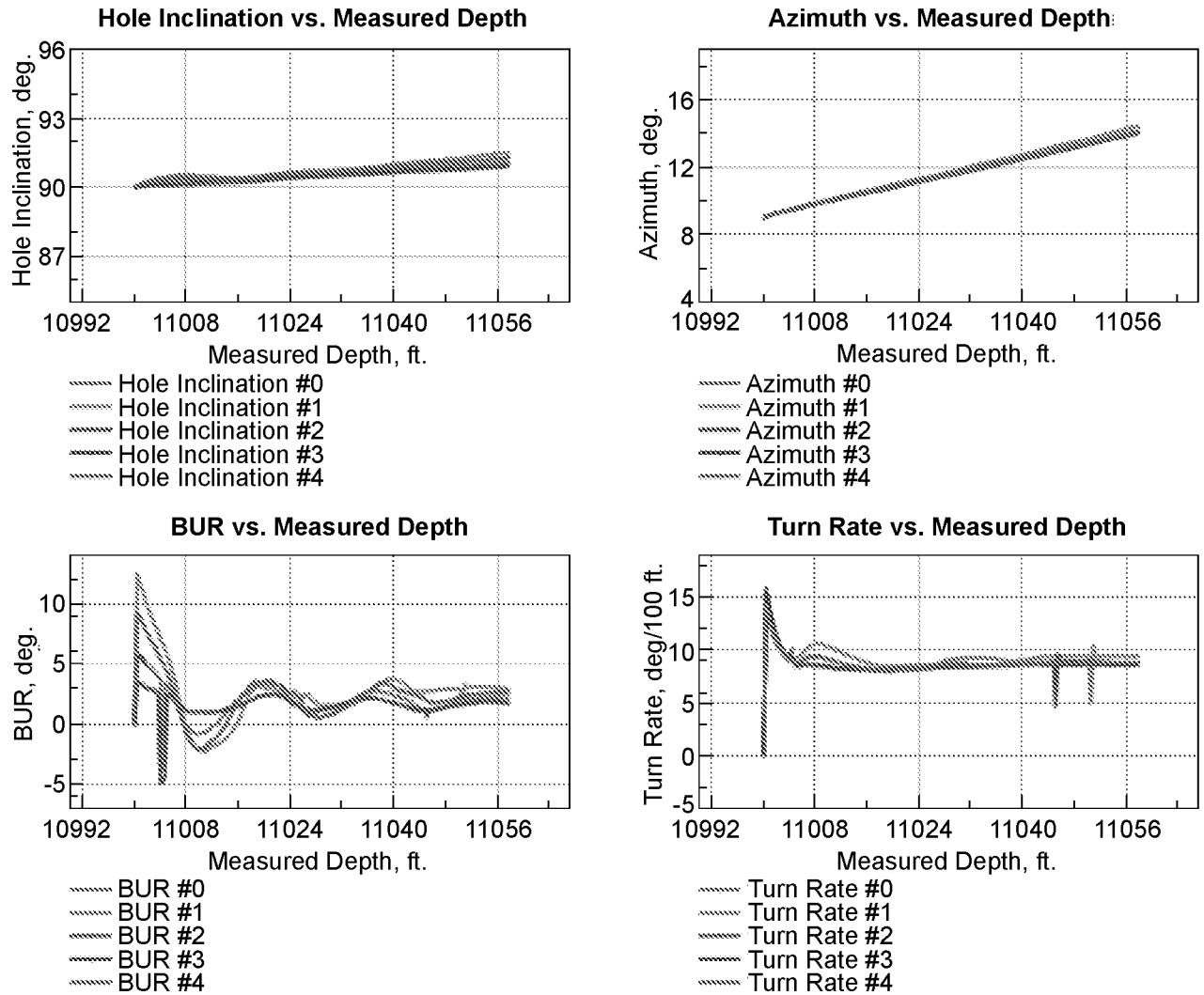


FIG. 46

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2017/042876**A. CLASSIFICATION OF SUBJECT MATTER****E21B 44/02(2006.01)i, E21B 44/04(2006.01)i, E21B 44/06(2006.01)i, E21B 7/06(2006.01)i, E21B 41/00(2006.01)i, E21B 45/00(2006.01)i, E21B 47/12(2006.01)i, G06F 17/50(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 44/02; E21B 7/00; G01V 3/00; E21B 7/08; G01V 3/18; E21B 7/04; E21B 44/04; E21B 44/06; E21B 7/06; E21B 41/00; E21B 45/00; E21B 47/12; G06F 17/50

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 trajectory, control, calculate, determine, predict, bit walk, spiral

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 4804051 A (HO, HWA-SHAN) 14 February 1989 See column 1, line 7 - column 16, line 40; claims 3, 15; and figures 1-12.	1,3-4,6-15,18,20
Y		2,5,16-17,19
Y	US 2013-0043077 A1 (CHEN, SHILIN) 21 February 2013 See paragraphs [0005]-[0012], [0055]-[0165]; claim 12; and figures 1A-1C, 2A-2B, 17A-17G.	2,5,16-17,19
A	US 6438495 B1 (CHAU et al.) 20 August 2002 See column 1, line 6 - column 7, line 33; and figures 1-10.	1-20
A	US 6443242 B1 (NEWMAN et al.) 03 September 2002 See column 1, line 7 - column 5, line 49; and figures 1-4.	1-20
A	US 2010-0259415 A1 (STRACHAN et al.) 14 October 2010 See paragraphs [0001]-[0070]; and figures 1-4, 5A-5I, 6-10.	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

16 October 2017 (16.10.2017)

Date of mailing of the international search report

16 October 2017 (16.10.2017)

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

LEE, Se Gyoung

Telephone No. +82-42-481-8740



INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2017/042876

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 4804051 A	14/02/1989	None	
US 2013-0043077 A1	21/02/2013	AU 2008-338627 A1	25/06/2009
		AU 2008-338627 B2	10/04/2014
		CA 2624106 A1	15/02/2007
		CA 2624106 C	09/07/2013
		CA 2625009 A1	15/02/2007
		CA 2625009 C	20/12/2016
		CA 2625012 A1	15/02/2007
		CA 2625012 C	03/05/2016
		CA 2684276 A1	30/10/2008
		CA 2684276 C	04/10/2016
		CA 2704718 A1	20/11/2010
		CA 2706343 A1	25/06/2009
		CA 2706343 C	23/08/2016
		CA 2907330 A1	30/10/2008
		CA 2907330 C	17/01/2017
		CA 2921128 A1	15/02/2007
		EP 1929117 A1	11/06/2008
		EP 1931854 A1	18/06/2008
		EP 1931858 A1	18/06/2008
		EP 2149104 A1	03/02/2010
		EP 2240881 A1	20/10/2010
		EP 2258918 A2	08/12/2010
		EP 2264275 A2	22/12/2010
		EP 2281996 A2	09/02/2011
		GB 2443125 A	23/04/2008
		GB 2443125 B	08/02/2012
		GB 2443126 A	23/04/2008
		GB 2443126 B	28/03/2012
		GB 2443127 A	23/04/2008
		GB 2443127 B	14/12/2011
		GB 2482850 A	15/02/2012
		GB 2482850 B	28/03/2012
		GB 2482851 A	15/02/2012
		GB 2482851 B	04/04/2012
		GB 2483022 A	22/02/2012
		GB 2483022 B	04/04/2012
		NO 20081184 A	05/05/2008
		NO 20081185 A	05/05/2008
		NO 20081187 A	05/05/2008
		US 2007-0029111 A1	08/02/2007
		US 2007-0029113 A1	08/02/2007
		US 2007-0032958 A1	08/02/2007
		US 2007-0192074 A1	16/08/2007
		US 2009-0090556 A1	09/04/2009
		US 2009-0229888 A1	17/09/2009
		US 2010-0300758 A1	02/12/2010
		US 2011-0015911 A1	20/01/2011

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2017/042876

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
		US 2011-0077928 A1	31/03/2011
		US 7729895 B2	01/06/2010
		US 7778777 B2	17/08/2010
		US 7827014 B2	02/11/2010
		US 7860693 B2	28/12/2010
		US 7860696 B2	28/12/2010
		US 8145465 B2	27/03/2012
		US 8296115 B2	23/10/2012
		US 8352221 B2	08/01/2013
		US 8606552 B2	10/12/2013
		WO 2007-019471 A1	15/02/2007
		WO 2007-019472 A1	15/02/2007
		WO 2007-019483 A1	15/02/2007
		WO 2008-130997 A1	30/10/2008
		WO 2009-079371 A1	25/06/2009
US 6438495 B1	20/08/2002	AU 2001-46173 A1	06/12/2001
		AU 2001-46173 B2	13/03/2003
		BR 0104079 A	12/03/2002
		CA 2348554 A1	26/11/2001
		CA 2348554 C	31/01/2006
		GB 2367626 A	10/04/2002
		GB 2367626 B	04/06/2003
		GB 2384567 A	30/07/2003
		NO 20012568 A	27/11/2001
		NO 323301 B1	05/03/2007
US 6443242 B1	03/09/2002	None	
US 2010-0259415 A1	14/10/2010	GB 2468251 A	01/09/2010
		GB 2468251 B	15/08/2012
		US 8274399 B2	25/09/2012
		WO 2009-075667 A2	18/06/2009
		WO 2009-075667 A3	09/06/2016