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(54) **REAL-TIME RANGING WHILE DRILLING**

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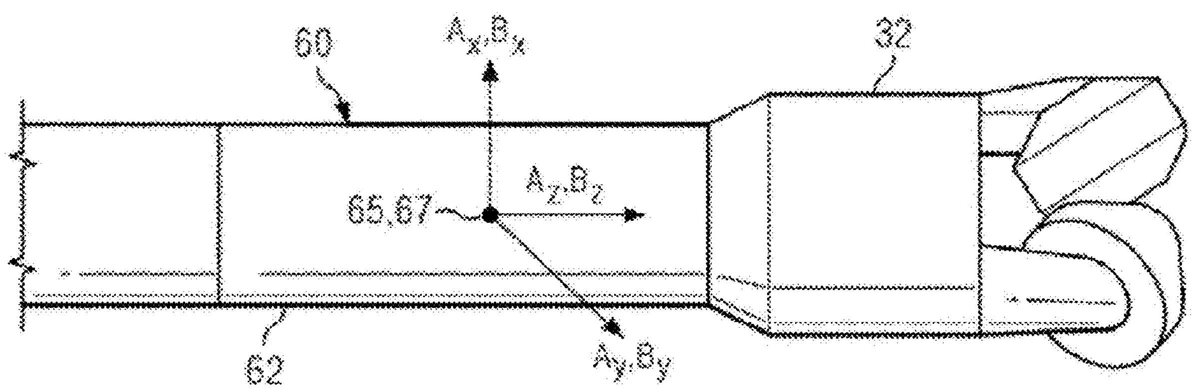
(57) **ABSTRACT**

Methods and related systems for drilling a subterranean wellbore includes rotating a bottomhole assembly (BHA) to drill the wellbore. The BHA includes a cutting tool and at least one sensor. The at least one sensor is configured to make measurements while drilling. These measurements are processed to compute a magnetic field profile, which is further processed to identify and characterize a signature or pattern in the magnetic field profile that is representative of a target well proximate to the wellbore being drilled. At least one of a distance or a direction to the target well can be computed based on characteristics of the signature or pattern in the magnetic field profile. The computed distance or direction to the target well can be used to control the direction of drilling of the wellbore.



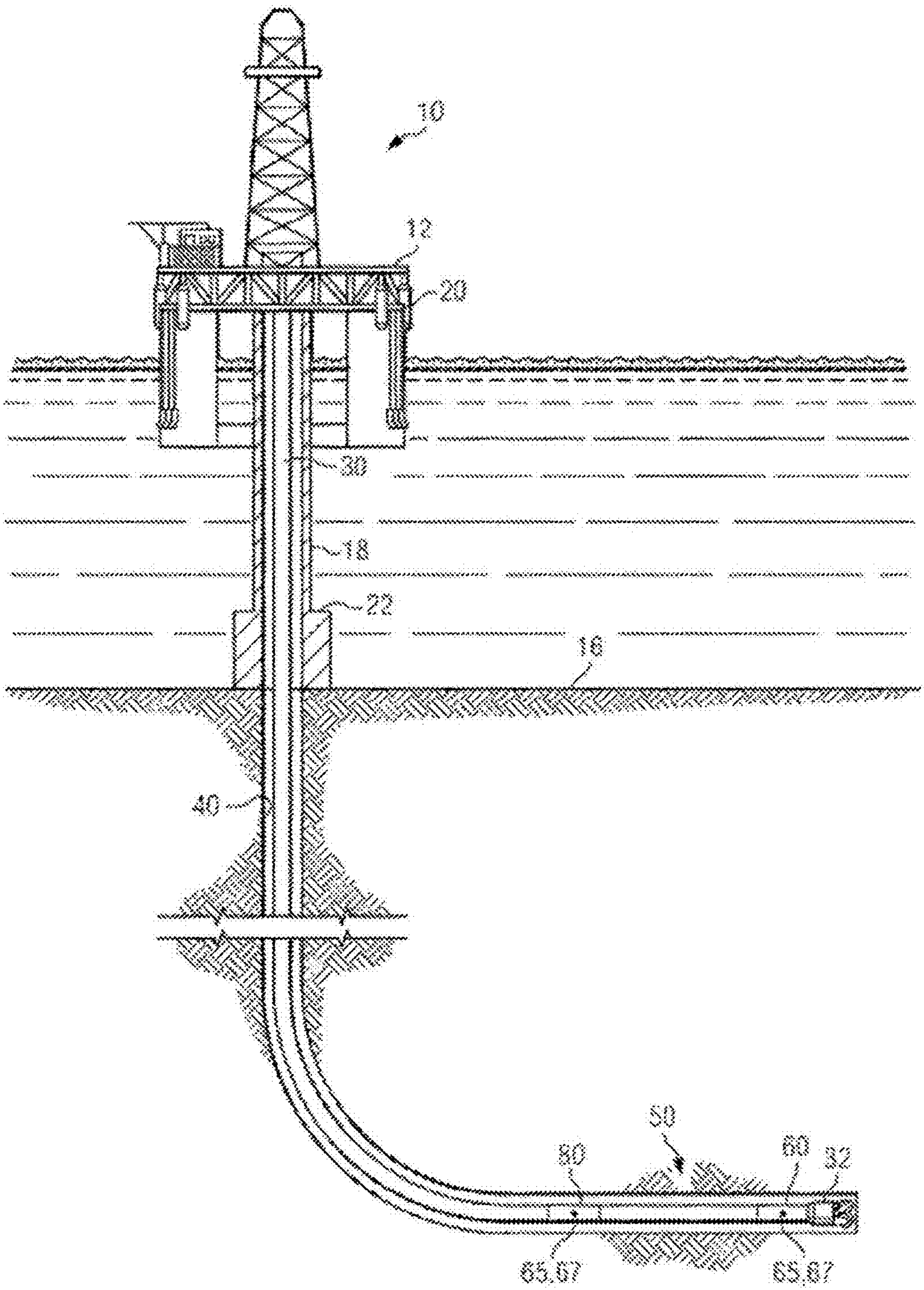


FIG. 1

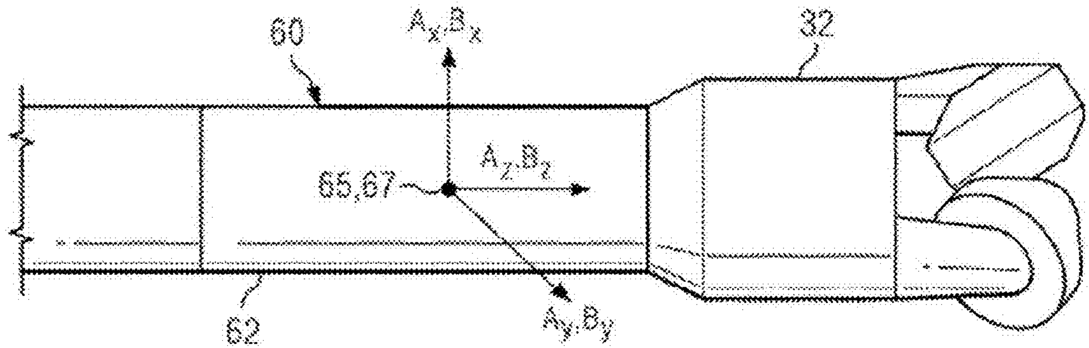

60
A_x,B_x
32
A_z,B_z
65,67
62
A_y,B_y

FIG. 2

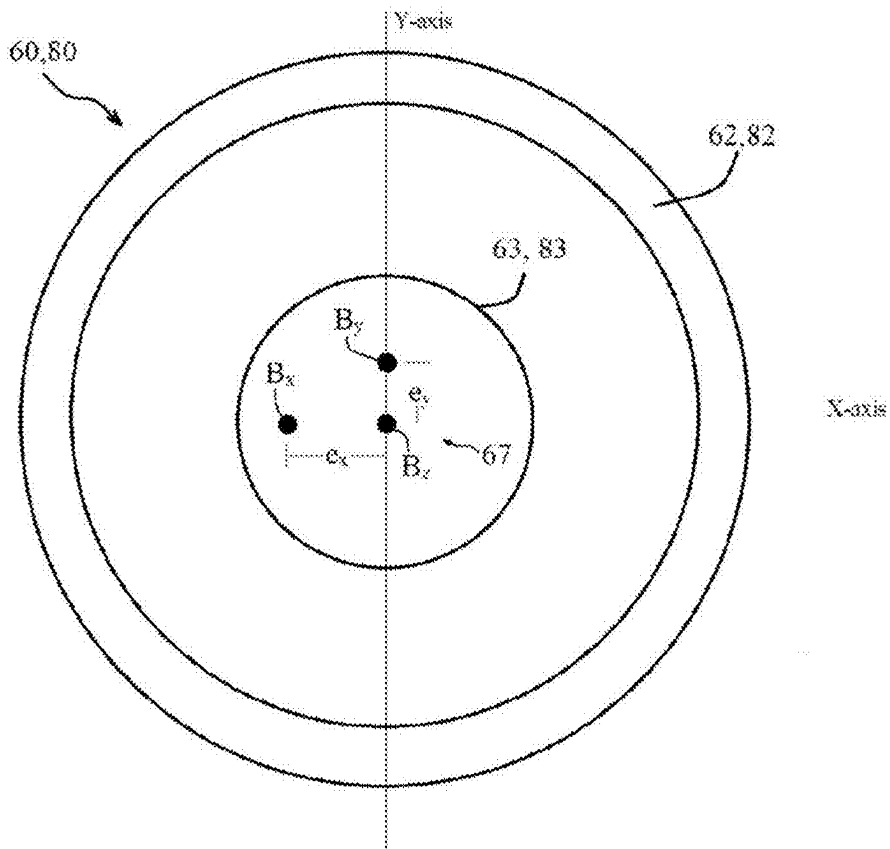

Y-axis
60,80
62,82
63, 83
B_y
B_x
e_y
X-axis
e_x
B_z
67

FIG. 3

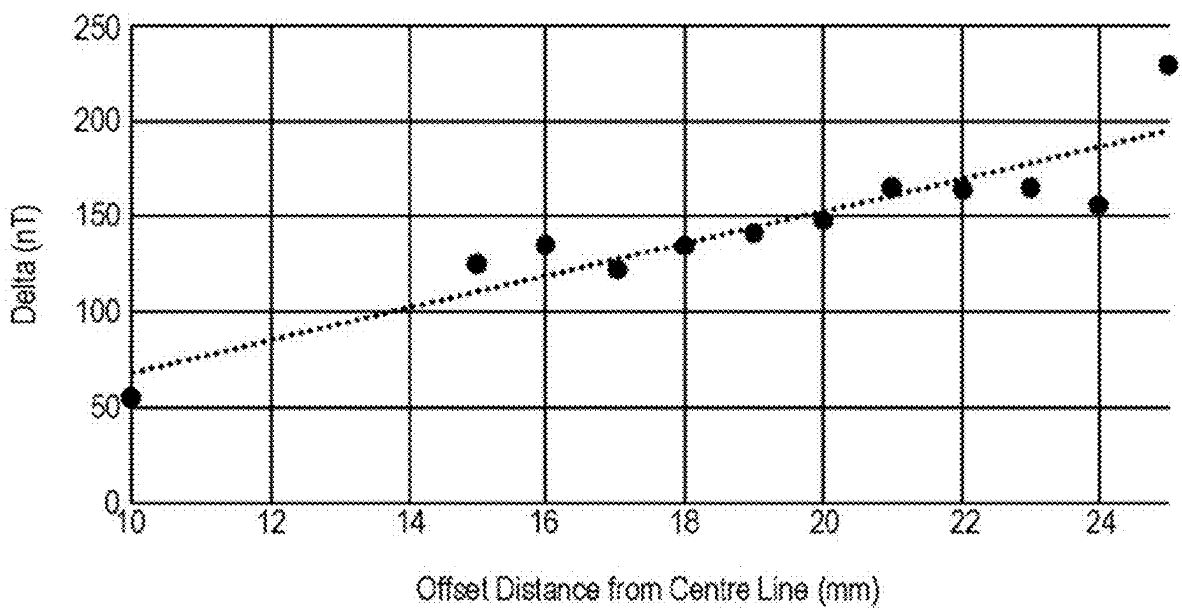

250
200
150
100
50
0
Delta (nT)
10
12
14
16
18
20
22
24
Offset Distance from Centre Line (mm)

FIG. 4

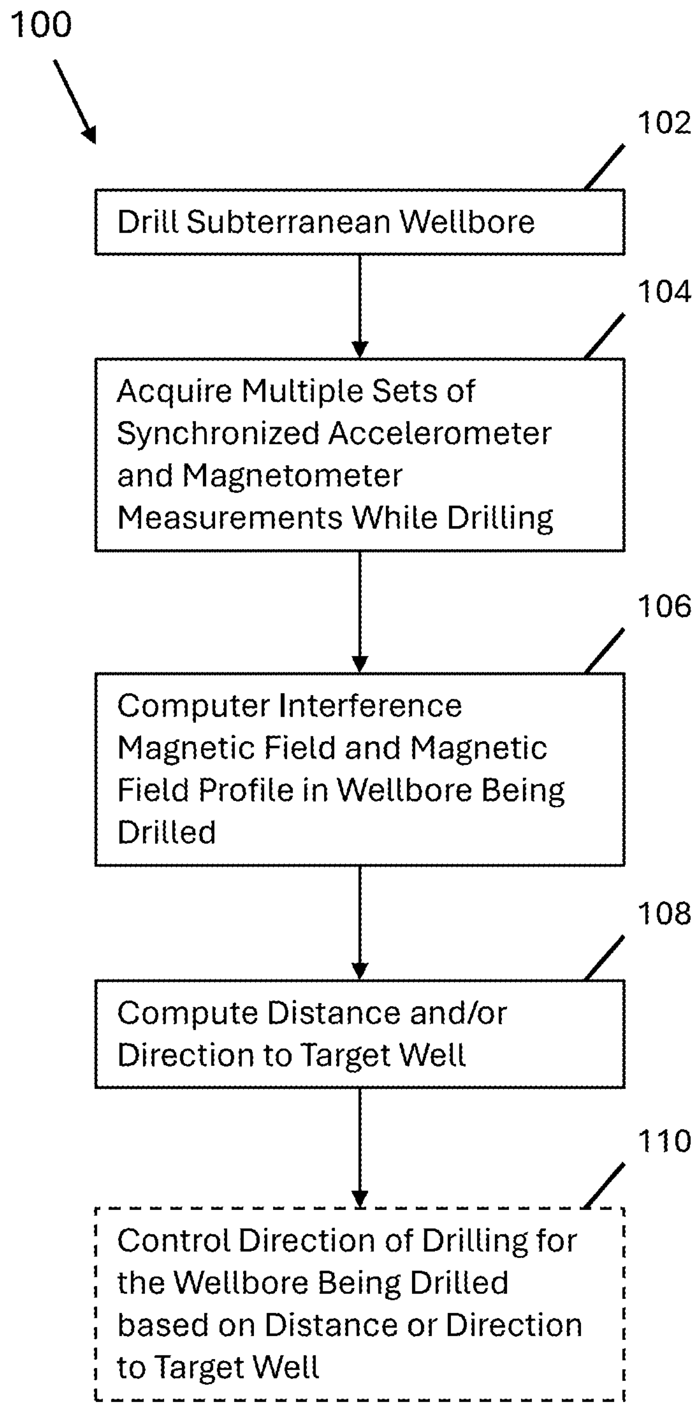

100
102
Drill Subterranean Wellbore
104
Acquire Multiple Sets of Synchronized Accelerometer and Magnetometer Measurements While Drilling
106
Computer Interference Magnetic Field and Magnetic Field Profile in Wellbore Being Drilled
108
Compute Distance and/or Direction to Target Well
110
Control Direction of Drilling for the Wellbore Being Drilled based on Distance or Direction to Target Well

FIG. 5-1

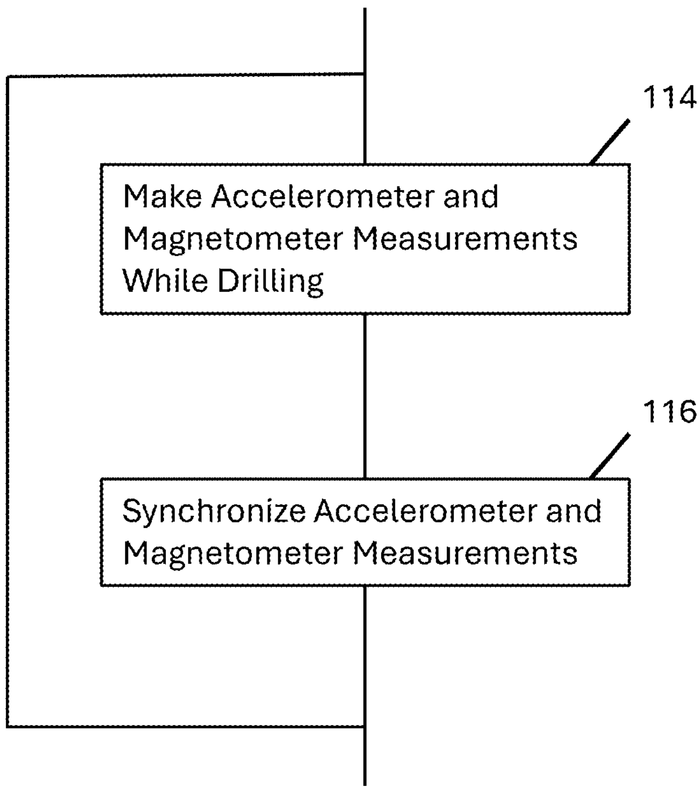

114
Make Accelerometer and Magnetometer Measurements While Drilling
116
Synchronize Accelerometer and Magnetometer Measurements

FIG. 5-2

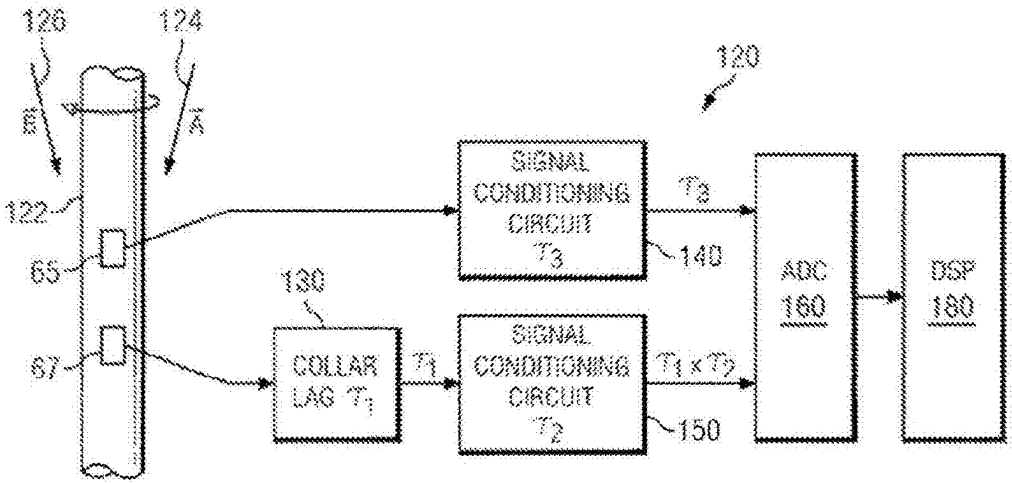

126
124
120
B
A
122
65
67
SIGNAL CONDITIONING CIRCUIT T_3
T_3
140
130
COLLAR LAG T_1
T_1
SIGNAL CONDITIONING CIRCUIT T_2
$T_1 \times T_2$
150
ADC 160
DSP 180

FIG. 6

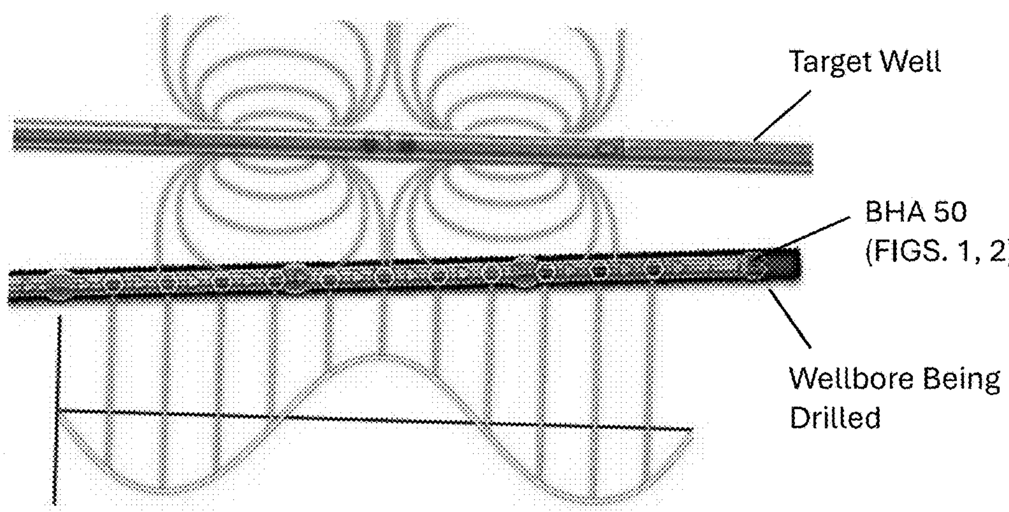

Target Well
BHA 50
(FIGS. 1, 2)
Wellbore Being
Drilled

FIG. 7

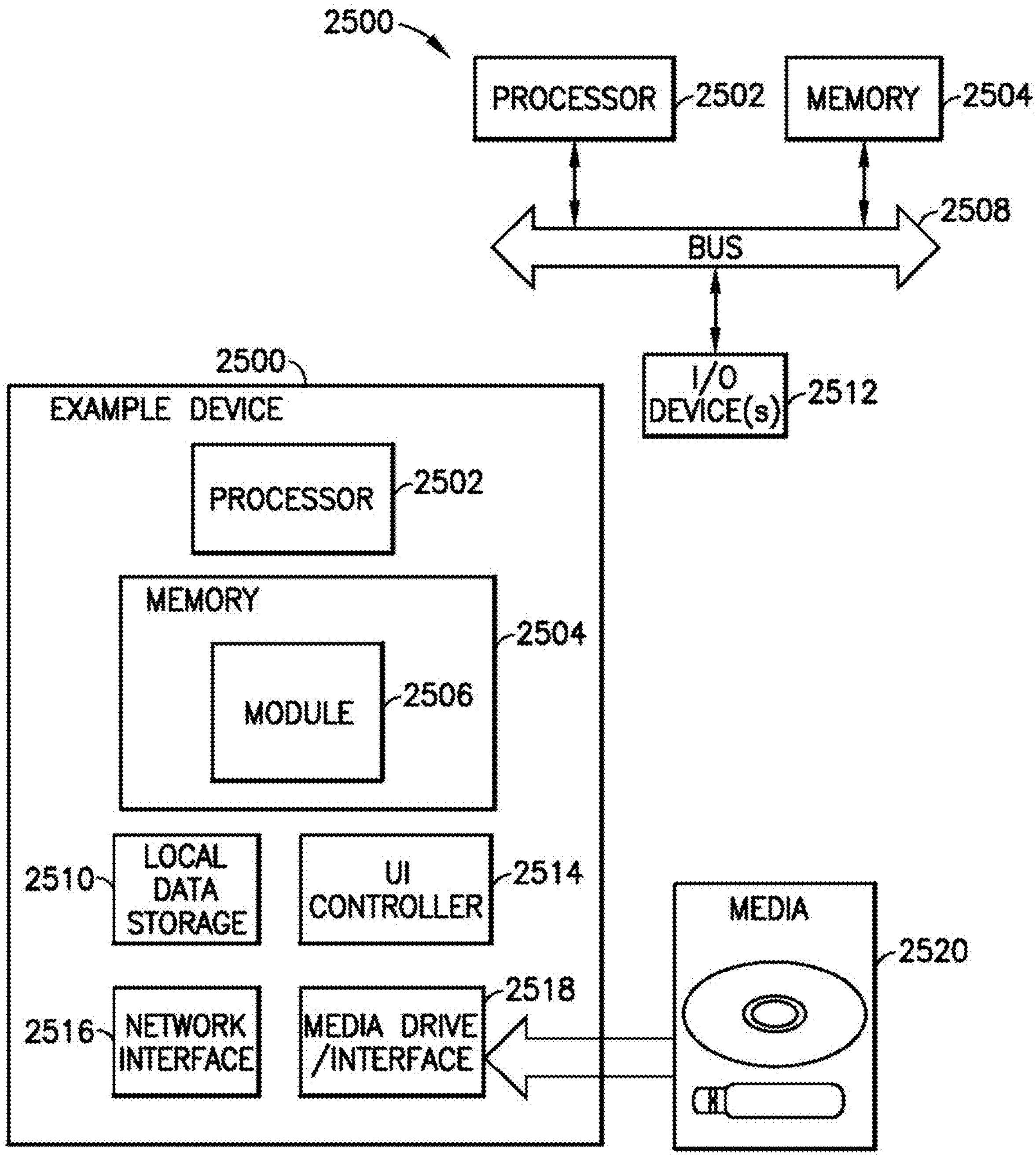

2500
PROCESSOR
2502
MEMORY
2504
BUS
2508
I/O DEVICE(s)
2512
2500
EXAMPLE DEVICE
PROCESSOR
2502
MEMORY
2504
MODULE
2506
LOCAL DATA STORAGE
2510
UI CONTROLLER
2514
NETWORK INTERFACE
2516
MEDIA DRIVE /INTERFACE
2518
MEDIA
2520

FIG. 8

REAL-TIME RANGING WHILE DRILLING

CROSS-REFERENCE TO RELATED APPLICATION(S)

[0001] The present disclosure claims priority from U.S. Provisional Appl. No. 63/555,698, filed on Feb. 20, 2024, herein incorporated by reference in its entirety.

BACKGROUND

[0002] In subterranean drilling operations the need frequently arises to determine the relative location of the wellbore being drilled (the drilling well) with respect to a pre-existing offset wellbore (a target well) or other subterranean structure. This need may exist for the purpose of avoiding a collision, for the purpose of making an interception, or for the purpose of maintaining a specified separation distance between the wells (e.g., in well twinning operations). Magnetic ranging techniques may be employed to determine the relative location of the target well (or structure), for example, by making magnetic field measurements in the drilling well. The measured magnetic field may be induced in part by ferromagnetic material or an electromagnetic source (or sources) in the target well such that the measured magnetic field vector may enable the relative location of the target well to be computed.

[0003] Existing magnetic ranging techniques are commonly similar to conventional static surveys in that they require drilling to be halted and the drill string to be held stationary in the drilling well while each magnetic survey is obtained. Such magnetic ranging operations are therefore costly and time consuming. There is a need in the art for methods for magnetic ranging measurements while drilling (i.e., without halting drilling and holding the drill string stationary).

SUMMARY

[0004] Methods and related systems for drilling a subterranean wellbore includes rotating a bottomhole assembly (BHA) to drill the wellbore. The BHA includes a cutting tool and at least one sensor. The at least one sensor is configured to make measurements while drilling. These measurements are processed to compute a magnetic field profile, which is further processed to identify and characterize a signature or pattern in the magnetic field profile that is representative of a target well proximate to the wellbore being drilled. At least one of a distance or a direction to the target well can be computed based on characteristics of the signature or pattern in the magnetic field profile. The computed distance or direction to the target well can be used to control the direction of drilling of the wellbore.

[0005] In embodiments, the at least one sensor can include a triaxial accelerometer set and a triaxial magnetometer set.

[0006] In embodiments, the at least one sensor can further include at least one gyroscope.

[0007] In embodiments, the signature or pattern in the magnetic field profile that is representative of the target well can include a sinusoidal signature or pattern.

[0008] In embodiments, the computed distance to the target well can be based on magnitude of the sinusoidal signature or pattern in the magnetic field profile.

[0009] In embodiments, the computed direction to the target well can be based on wavelength of the sinusoidal signature or pattern in the magnetic field profile.

[0010] In embodiments, the signature or pattern in the magnetic field profile that is representative of the target well can be defined by structural features (such as the body and shoulders of casing joints or liner joints) of the target well.

[0011] In embodiments, the magnetic field profile can be computed from the measurements of the at least one sensor at survey points of varying measured depth in the wellbore being drilled.

[0012] In embodiments, the magnetic field profile can include a plurality of measured magnetic vectors as a function of measured depth along the wellbore axis.

[0013] In embodiments, each measured magnetic vector can be represented by a magnitude and an orientation, wherein the magnitude is computed by subtracting contribution of the earth magnetic field from readings of a tri-axial magnetometer set, and wherein the orientation is determined from synchronous readings of a tri-axial accelerometer set.

[0014] In embodiments the computed distance or direction to the target well can be used to control the direction of drilling of the wellbore to follow, intercept or avoid the target well.

[0015] In embodiments, the BHA can further include a rotary steerable drilling tool with a steering element. The direction of drilling of the wellbore can be adjusted based on the computed distance or direction to the target well and the direction of drilling of the wellbore can be controlled by actuation of the steering element of the rotary steerable tool to change direction of drilling.

[0016] This summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to identify key or essential features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter.

BRIEF DESCRIPTION OF THE DRAWINGS

[0017] For a more complete understanding of the disclosed subject matter, and advantages thereof, reference is now made to the following descriptions taken in conjunction with the accompanying drawings, in which:

[0018] FIG. **1** depicts an example drilling environment in which disclosed embodiments may be utilized;

[0019] FIG. **2** depicts a lower BHA portion of the drill string shown in FIG. **1**;

[0020] FIG. **3** is a cross-sectional view of an example measurement tool including eccentered transverse magnetic field sensors;

[0021] FIG. **4** is a plot of the interference magnetic field, Delta (nT), versus offset distance of an eccentered transverse magnetic field sensor;

[0022] FIGS. **5-1** and **5-2** (collectively FIG. **5**) are flow charts of example methods for drilling a subterranean wellbore;

[0023] FIG. **6** is a schematic diagram of an embodiment of a system suitable for executing methods for drilling a subterranean wellbore such as the methods of FIG. **5**;

[0024] FIG. **7** is a schematic diagram of a sinusoidal pattern or signature representative of a target well in a magnetic profile measured as part of the methods of FIG. **5**; and

[0025] FIG. **8** is a schematic diagram of a computer processing system.

DETAILED DESCRIPTION

[0026] The particulars shown herein are by way of example and for purposes of illustrative discussion of the embodiments of the subject disclosure only and are presented in the cause of providing what is believed to be the most useful and readily understood description of the principles and conceptual aspects of the subject disclosure. In this regard, no attempt is made to show structural details in more detail than is necessary for the fundamental understanding of the subject disclosure, the description taken with the drawings making apparent to those skilled in the art how the several forms of the subject disclosure may be embodied in practice. Furthermore, like reference numbers and designations in the various drawings indicate like elements.

[0027] Methods and systems for drilling a subterranean wellbore rotate a bottomhole assembly (BHA) to drill the wellbore. The BHA includes a drill collar, a drill bit or other cutting tool, and a triaxial accelerometer set and a triaxial magnetometer set deployed in the drill collar. The triaxial accelerometer set and the triaxial magnetometer set can be configured to make accelerometer measurements and magnetometer measurements while drilling. These measurements can be synchronized and processed to compute an interference magnetic field, which is in turn processed to compute at least one of a distance or a direction to a target well located external to the wellbore. In certain embodiments, the triaxial magnetometer set may include at least one eccentered transverse magnetic field sensor that is radially offset from a centerline of the drill collar. In such embodiments the interference magnetic field may include a difference between first and second magnetic field measurements made by the eccentered sensor at diametrically opposed toolface angles.

[0028] The disclosed embodiments may provide various technical advantages and improvements over the prior art. For example, in some embodiments, the disclosed embodiments provide an improved method and system for drilling a subterranean wellbore in which it is desirable to make magnetic ranging measurements to a target structure in substantially real-time while drilling (e.g., several measurements per minute or several measurements per foot or per meter of measured depth of the wellbore). The disclosed embodiments may therefore provide a much higher density of magnetic ranging measurements and/or may save considerable rig time as the ranging measurements do not require a stoppage in drilling. The ranging measurements may be advantageously utilized, for example, in wellbore intercept, wellbore avoidance, and well twinning operations.

[0029] FIG. **1** depicts a drilling rig **10** suitable for using various method embodiments disclosed herein. A semisubmersible drilling platform **12** is positioned over an oil or gas formation disposed below the sea floor **16**. A subsea conduit **18** extends from deck **20** of platform **12** to a wellhead installation **22**. The platform may include a derrick and a hoisting apparatus for raising and lowering a drill string **30**, which, as shown, extends into wellbore **40** and includes a cutting tool such as drill bit **32** and a rotary steerable tool **60**. In some embodiments, the drill bit **32** is a fixed cutter drill bit, a roller cone drill bit, an impregnated drill bit, or a hybrid drill bit (e.g., a combination with fixed cutter blades and roller cones). In the same or other embodiments, the cutting tool can be other components in addition to, or other than, the drill bit **32**, including a fixed reamer, hole opener, expandable reamer, window mill, junk mill, taper mill, dress mill, or other cutting tools.

[0030] Drill string **30** may further include a downhole drilling motor, a downhole telemetry system, and one or more MWD or LWD tools including various sensors for sensing downhole characteristics of the wellbore and the surrounding formation. The disclosed embodiments are not limited in these regards.

[0031] It will be understood by those of ordinary skill in the art that the deployment illustrated in FIG. **1** is merely an example. It will be further understood that disclosed embodiments are not limited to use with a semisubmersible platform **12** as illustrated in FIG. **1**. The disclosed embodiments are equally well suited for use with any kind of subterranean drilling operation, either offshore or onshore.

[0032] FIG. **2** depicts the lower BHA portion of drill string **30** including drill bit **32** and rotary steerable tool **60**. In the depicted embodiment, rotary steerable tool body **62** is connected with the drill bit **32** and may be (or may not be) configured to rotate with the drill bit **32**. Rotary steerable tools **60** include steering elements that may be actuated to control and/or change the direction of drilling the wellbore **40**. In embodiments employing a rotary steerable tool, substantially any suitable rotary steerable tool configuration may be used. Various rotary steerable tool configurations are known in the art. For example, some rotary steerable systems include a substantially non-rotating (or slowly rotating) outer housing employing blades that engage the wellbore wall. Engagement of the blades with the wellbore wall is intended to eccenter the tool body, thereby pointing or pushing the drill bit or other cutting tool in a desired direction while drilling. A rotating shaft deployed in the outer housing transfers rotary power and axial weight-on-bit to the cutting tool during drilling. Accelerometer and magnetometer sets may be deployed in the outer housing and therefore are non-rotating or rotate slowly with respect to the wellbore wall.

[0033] The POWERDRIVE rotary steerable system (available from SLB of Houston, Texas) fully rotates with the drill string (i.e., the outer housing rotates with the drill string). The POWERDRIVE XCEED systems make use of an internal steering mechanism that will not require contact with the wellbore wall and enables the tool body to fully rotate with the drill string. The POWERDRIVE XS, X6, and ORBIT rotary steerable systems make use of mud actuated blades (or pads) that contact the wellbore wall. The extension of the blades (or pads) is rapidly and continually adjusted as the system rotates in the wellbore. The POWERDRIVE ARCHER systems make use of a lower steering section joined at a swivel with an upper section. The swivel is actively tilted via pistons so as to change the angle of the lower section with respect to the upper section and maintain a desired drilling direction as the bottomhole assembly rotates in the wellbore. Accelerometer and magnetometer sets may rotate with the drill string or may alternatively be deployed in an internal roll-stabilized housing such that they remain substantially stationary (in a bias phase) or rotate slowly with respect to the wellbore (in a neutral phase). To drill a desired curvature, the bias phase and neutral phase are alternated during drilling at a predetermined ratio (referred to as the steering ratio).

[0034] While FIG. **2** depicts a rotary steerable tool **60**, it will be understood the disclosed embodiments are not limited to the use of a rotary steerable tool. Moreover, while the accelerometer and magnetometer sensor sets **65** and **67** may be deployed and processed in a rotary steerable tool (as depicted in FIG. **2**), they may also be located elsewhere within the drill string. With reference again to FIG. **1**, drill string **30** may further include a measurement while drilling tool **80** including corresponding accelerometer and magnetometer sensor sets **65** and **67**. As depicted, the MWD tool **80** is commonly deployed further uphole in the drill string (i.e., above the rotary steerable tool **60**). As is known to those of ordinary skill in the art, such MWD tools **80** may rotate with the drill string and may further include a mud pulse telemetry transmitter or other telemetry system, an alternator for generating electrical power, and an electronic controller. It will thus be appreciated that the disclosed embodiments are not limited to any specific deployment location of the accelerometer and magnetometer sensor sets **65** and **67** in the drill string.

[0035] With continued reference to FIGS. **1** and **2**, the depicted rotary steerable tool **60** and/or MWD tool include (s) tri-axial accelerometer **65** and tri-axial magnetometer **67** navigation sensor sets, which may include any suitable commercially available devices. Suitable accelerometers for use in sensor set **65** may be chosen from among substantially any suitable commercially available devices known in the art. Suitable accelerometers may alternatively include micro-electro-mechanical systems (MEMS) solid-state accelerometers, which tend to be shock resistant, high-temperature rated, and inexpensive. Suitable magnetic field sensors for use in sensor set **67** may include conventional ring core flux gate magnetometers or conventional magnetoresistive sensors.

[0036] FIG. **2** further includes a diagrammatic representation of the tri-axial accelerometer and magnetometer sensor sets **65** and **67**. By tri-axial it is meant that each sensor set includes three mutually perpendicular sensors, the accelerometers being designated as A_x, A_y, and A_z and the magnetometers being designated as B_x, B_y, and B_z. B_y convention, a right handed system is designated in which the z-axis accelerometer and magnetometer (A_z and B_z, respectively) are oriented substantially parallel with the tool axis (and therefore the wellbore axis) as indicated (although disclosed embodiments are not limited by such conventions). Each of the accelerometer and magnetometer sets may therefore be considered as determining a plane (the x and y-axes) and a pole (the z-axis along the axis of the BHA). It will be appreciated that the vector representation in FIG. **2** is diagrammatic and schematic and not necessarily intended to disclose or imply that the accelerometers and magnetometers are deployed at precisely the same location in the tool body **62**.

[0037] By convention, the gravitational field is taken to be positive pointing downward (i.e., toward the center of the earth) while the magnetic field is taken to be positive pointing towards magnetic north. Moreover, also by convention, the y-axis is taken to be the toolface reference axis (i.e., gravity toolface T equals zero when the y-axis is uppermost, and magnetic toolface M equals zero when the y-axis is pointing towards the projection of magnetic north in the xy plane). The magnetic toolface M is projected in the xy plane and may be represented mathematically as:

$$\tan M = B_x/B_y.$$

Likewise, the gravity toolface T may be represented mathematically as:

$$\tan T = (-A_x)/(-A_y).$$

The negative signs in the gravity toolface expression arise owing to the convention that the gravity vector is positive in the downward direction while the toolface angle Tis positive on the high side of the wellbore (the side facing upward).

[0038] The disclosed method embodiments are not limited to the above described conventions for defining wellbore coordinates. These conventions can affect the form of certain of the mathematical equations that follow in this disclosure. Those of ordinary skill in the art will be readily able to utilize other conventions and derive equivalent mathematical equations.

[0039] The accelerometer and magnetometer sets **65**, **67** may be configured for making downhole navigational (surveying) measurements during a drilling operation. Such measurements are well known and commonly used to determine, for example, wellbore inclination, wellbore azimuth, gravity toolface, magnetic toolface, and dipping angle (dip). Moreover, the magnetometers are further configured for measuring one or more external magnetic fields, for example, emanating from an external target well. The accelerometers and magnetometers may be electrically coupled to a digital signal processor (or other digital controller) through corresponding signal analog signal conditioning circuits as described in more detail below. The signal conditioning circuits may include low-pass filter elements that are intended to band-limit sensor noise and therefore tend to improve sensor resolution and surveying accuracy.

[0040] While the disclosed embodiments are not limited in this regard, it has been found that in certain example embodiments sensitivity to external interference magnetic fields may be improved via the use of eccentered (radially offset) transverse magnetic field sensors. For example, in embodiments that make use of a triaxial magnetic field sensor (e.g., sensor **67** in FIG. **2**) it may be advantageous to eccenter the B_x and/or B_y magnetic field sensors (the transverse magnetic field sensors). B_y eccenter it is meant that the B_x and/or B_y magnetic field sensors are radially offset from the rotational center of the tool body (e.g., tool body **62** in FIG. **2**). In various embodiments the transverse magnetic field sensors may have equal or unequal eccentering distances. For example, in one example embodiment, the B_x and B_y magnetic field sensors may have equal eccentering distances (such that $e_x=e_y$). In another example embodiment, the B_x and B_y magnetic field sensors may have unequal eccentering distances (such that $e_x \neq e_y$).

[0041] FIG. **3** is a cross-sectional view of an example measurement tool **60**, **80** including at least one eccentered transverse magnetic field sensor. The tool **60**, **80** may include, for example, a rotary steerable tool or an MWD tool as described above with respect to FIGS. **1** and **2**. The tool **60**, **80** includes a sensor housing **63**, **83** optionally deployed centrally in a tool collar **62**, **82**. The sensor housing **63**, **83** includes a triaxial magnetic field sensor **67** deployed therein including a centered axial magnetic field sensor B_z and at least one eccentered transverse magnetic field sensor B_x and/or B_y. In the example embodiment depicted, the transverse magnetic field sensors B_x and B_y are radially offset from a central location (such as the tool center along a central, longitudinal axis) by corresponding eccentering distances e_x and e_y. As noted above, the eccentering distances e_x and e_y may be equal or unequal. Moreover, in certain embodiments only one of the transverse magnetic field sensors B_x and B_y is eccentered (such that either e_x or e_y equals zero).

[0042] It has been found that the use of at least one eccentered transverse magnetic field sensor advantageously increases the interference magnetic field while ranging. The use of at least one eccentered transverse magnetic field sensor may therefore improve ranging sensitivity and/or accuracy. For example, increasing the interference magnetic field strength may advantageously enable magnetic detection and ranging to target well(s) that are located a greater distance from the drilling well or may enable ranging to weaker target well(s). Moreover, increasing the interference magnetic field strength may also advantageously increase signal to noise ratio and therefore improve the accuracy of the computed distance and direction to the target well(s).

[0043] With reference to FIGS. **3** and **4**, at least one transverse magnetic field sensor can be eccentered by substantially any suitable eccentering distance. For example, in certain embodiments, the eccentering distance may be from 0 mm to 40 mm (e.g., from 10 mm to 30 mm, from 15 mm to 30 mm, or from 20 to 25 mm). The eccentering distance may also be specified with respect to the diameter of the sensor housing **63**, **83**. For example, the eccentering distance may be from 0% to 40% of the diameter of the sensor housing (e.g., from 20% to 40% or from 25% to 35% of the diameter of the sensor housing).

[0044] FIG. **4** is a plot of the interference magnetic field strength (on the vertical axis) versus the transverse magnetic field sensor eccentering distance (on the horizontal axis) for one example laboratory calibration measurement in which a magnetic object was located in sensory range of the magnetic field sensors **67**. In this example, the interference magnetic field is a difference between first and second magnetic field measurements made at diametrically opposed toolface angles (e.g., at toolface angles of 90 and 270 degrees in the plot). In certain embodiments, the interference magnetic field is maximized when the first and second magnetic field measurements are made at toolface angles of 90 and 270 degrees. Note also that this magnetic field strength difference (the interference magnetic field) increases substantially linearly with increasing eccentering distance.

[0045] In embodiments, a target well can extend in proximity to the wellbore being drilled within sensory range of the magnetic field sensors **67** of the BHA **50** as shown in FIG. **7**. Structural features of the nearby target well, such as the body and shoulders of casing joints or liner joints, can produce an interference magnetic field that is detected and measured by the magnetic field sensors **67** while drilling the wellbore. The measurements of the interference magnetic field can be performed at different measured depths in the wellbore being drilled and such measurements can be processed to compute a magnetic field profile that represents strength of the interference magnetic field as a function of measured depth in the wellbore being drilled as shown in FIG. **7**. The magnetic field profile can be further processed to compute a distance and/or direction to a target well as described herein.

[0046] In embodiments, the magnetic field profile can include a plurality of measured magnetic vectors as a function of measured depth along the wellbore axis. In embodiments, the plurality of measured magnetic vectors can be derived from a dynamic survey of magnetometer measurements, accelerometer measurements and possibly gyroscope measurements performed at different measured depths while drilling, such as every one foot of measured depth. The survey can include triaxial magnetometer readings and corresponding triaxial accelerometer measurements and possibly one or more gyroscope measurements at each survey point. The triaxial magnetometer readings for a given survey point measure three axial components that represent contribution of the earth magnetic field at the given survey point in addition to contribution of any interference magnetic field produced by the magnetic source in the nearby target well at the given survey point. The components that represent contribution of the earth magnetic field at the given survey point can be estimated prior to the survey and subtracted from the triaxial magnetometer readings at the given survey point to calculate axial components that represent the interference magnetic field produced by the nearby target well at the given survey point. The magnitude of the measured magnetic vector for the given survey point can be derived from the calculated axial components that represent the interference magnetic field produced by the nearby target well at the given survey point. The orientation of the measured magnetic vector for the given survey point can be derived from the orientation of the magnetometers during the triaxial magnetometer readings at the given survey point as determined from the synchronous triaxial accelerometer measurements at the given survey point.

[0047] In embodiments, a dynamic survey of magnetometer measurements and accelerometer measurements and gyroscope measurements can be performed at different measured depths. The survey can include average magnetometer measurements and average accelerometer measurements and average gyroscope measurements over predefined time intervals, such as time intervals of 20 seconds in duration. The magnetic vectors can be calculated from the average measurements of the survey at different measured depths while drilling, such as every one foot of measured depth or less. In this embodiment, the magnetic signature of the casing in an offset target well can be extracted from one or more magnetic vectors. When the target well is in close proximity to the wellbore being drilled, the corresponding gyroscopic measurements provide accurate azimuth which indicates the shoulders of the casing of the target well. With knowledge of the approximate position of the target well, the estimated pole strength of the collars of the target well and the distance between the collars of the target well, the method can calculate a range (or distance) and bearing (or direction) to the offset target well. Furthermore, the magnetic vectors can change during drilling and provide an indication that the drilling is getting closer or further away from the offset target well.

[0048] In embodiments, the body of casing of the target well can make up about 90% of the magnetic field profile measured by the magnetic field sensors of the BHA of the drilling tool, and the collars of the target well contribute stronger to this magnetic field profile but only for about 10%

of the length of the body of the casing. With knowledge of the length of the casing, the detection of the signature of the shoulders can be used to estimate the relative angle of the casing of the target well with respect to the borehole axis of the wellbore being drilled. The method can use this information to calculate a range (or distance) and bearing (or direction) to the target well.

[0049] FIGS. **5-1** and **5-2** (collectively FIG. **5**) are flow charts of one example method embodiment **100** for making magnetic ranging measurements while drilling a subterranean wellbore. A bottomhole assembly (e.g., as depicted in FIGS. **1** and **2**) can be rotated in the wellbore at **102** to drill the well. Synchronized accelerometer and magnetometer measurements (e.g., triaxial accelerometer and triaxial magnetometer measurements) are acquired at **104** while drilling (i.e., while rotating the bottomhole assembly in the wellbore to drill the well). For example, as shown in FIG. **5-2**, the acquisition of the synchronized accelerometer and magnetometer measurements at **104** may include repeatedly making triaxial accelerometer measurements and triaxial magnetometer measurements while drilling at **114** and synchronizing those measurements at **116**. In such embodiments, the synchronized accelerometer and magnetometer measurements may be made sequentially and may therefore be spaced along the axis of the wellbore as drilling progresses (e.g., several synchronized measurements per minute or several synchronized measurements per foot (or per meter) of measured depth of the wellbore). In other embodiments, synchronized gyroscope measurements can be part of the measurements acquired at **104** while drilling (i.e., while rotating the bottomhole assembly in the wellbore to drill the well).

[0050] With continued reference to FIG. **5-1**, the synchronized measurements of **104** are processed at **106** to compute an interference magnetic field as a function of measured depth along the wellbore being drilled, and the interference magnetic field as a function of measured depth along the wellbore being drilled may be further processed to compute a magnetic field profile, e.g., a measured magnetic vector as a function of measured depth along the wellbore axis. The magnetic field profile may be further processed to compute at least one of a distance and/or direction to a target well (offset well) at **108**. The computed distance and/or direction to the target well may then optionally be used for wellbore position and trajectory control while drilling at **110**. For example, the distance and/or direction to the target well can be used to adjust the direction of drilling (e.g., by adjusting the position of blades or other actuating components in a rotary steerable tool). In embodiments, the adjustment to the direction of drilling can be configured to intercept a target well such as another cased wellbore, or avoid one or more target wells, or drill parallel to a target well.

[0051] FIG. **6** is an example schematic diagram of an embodiment of a system **120** suitable for acquiring the synchronized accelerometer and magnetometer measurements and of executing method **100**. The system **120** includes a drill collar **122** (such as drill string **30** including rotary steerable tool **60** and/or MWD tool **80**) rotating in a subterranean wellbore (e.g., rotating while rotary drilling the wellbore). As described above with respect to FIG. **1**, the drill collar **122** may include triaxial accelerometer and triaxial magnetometer sets **65**, **67** deployed therein and configured to measure the Earth's gravitational field and the local magnetic field (including the Earth's magnetic field and any interference fields) while rotating. The gravitational and magnetic fields are depicted at **124** and **126** as acceleration vector A and field vector B. Owing to the rotation of the drill collar **122**, each of the accelerometers in the triaxial accelerometer set **65** measures a corresponding time varying gravitational field, $A_x(t)$, $A_y(t)$, $A_z(t)$. Likewise, each of the magnetometers in the triaxial magnetometer set **67** measures a corresponding time varying magnetic field, $B_x(t)$, $B_y(t)$, $B_z(t)$. These time varying gravitational field and magnetic field measurements are received (and filtered) by corresponding signal conditioning circuits **140** and **150**. The time varying measurements are then digitized at some predetermined frequency (e.g., in a range from 100 Hz to 1000 Hz) via an analog-to-digital converter **160**. The digitized measurements A_x, A_y, A_z and B_x, B_y, B_z are then received by a digital signal processor **180** where they are synchronized with one another and processed to compute the distance and/or direction to the target well (as well as to compute various survey parameters including, for example, wellbore inclination, wellbore azimuth, gravity toolface, magnetic toolface, and dip) in real-time while drilling. By real-time it is meant that the magnetic ranging measurements are computed while rotating the drill string to drill the wellbore (as opposed to conventional static measurements which are made while drilling has stopped). The real-time measurements may be computed at substantially any frequency, for example, in a range from 0.1 Hz to 100 Hz depending on how much averaging is employed. Such a measurement frequency corresponds to a measured depth interval ranging from a fraction of an inch to a few inches. Details of processing carried out by the digital signal processor **180** to compute the distance and/or direction to the target well is described in PCT Publ. WO 2024/011087, commonly owned by assignee of the subject application and herein incorporated by reference in its entirety.

[0052] In other embodiments, the drill collar **122** of FIG. **6** can include one or more gyroscopes for measuring attitude and direction of the drill collar **122** while drilling (i.e., while rotating the bottomhole assembly in the wellbore to drill the well).

[0053] In embodiments, the computed survey parameters and/or results of the ranging measurements may be stored in downhole memory and/or transmitted to the surface, for example, via mud pulse telemetry, electromagnetic telemetry (or other telemetry techniques). In such embodiments, the wellbore survey and ranging measurements may be constructed at the surface based upon the transmitted measurements.

[0054] The computed survey parameters and/or results of the ranging measurements may be used to control and/or change the direction of drilling. For example, in many drilling operations the wellbore (or a portion of the wellbore) is drilled along a drill plan, such as a predetermined direction (e.g., as defined by the wellbore inclination and the wellbore azimuth) or a predetermined curvature. In certain embodiments, the drilling direction may be selected to intercept a target well such as another cased wellbore. In other operations, the drilling direction may be selected to avoid one or more target wells. In still other embodiments (such as in well twinning), the drilling direction may be selected to parallel a target well. Changes in drilling direction may be implemented, for example, via actuating steering elements in a rotary steerable tool deployed above the bit. In some embodiments, the survey parameters may be sent directly to an RSS, which processes the survey parameters compared to the drill plan, (e.g., predetermined direction or predetermined curve) and changes drilling direction in order to meet the plan. In some embodiments the survey parameters may be sent to the surface using telemetry so that the survey parameters may be analyzed. In view of the survey parameters, drilling parameters (e.g., weight on bit, rotation rate, mud pump rate, etc.) may be modified and/or a downlink may be sent to the RSS to change the drilling direction. In some embodiments both downhole and surface control may be used.

[0055] In embodiments, the magnetic field profile computed from the synchronized accelerometer and magnetometer measurements (block **106**) can be processed to extract a magnetic signature or pattern representative of the nearby target well. In embodiments, the casing joints or liner joints of the nearby target well can produce a larger magnetic signal in the magnetic field profile relative to the body of the casing or liner of the nearby target well. Specifically, the magnetic field profile will have a maximum magnitude when drilling parallel to the nearby target well and passing by the casing joint end (or liner joint end) of the target well, and it will have a minimum magnitude when drilling parallel to the nearby target well and passing by the intermediate point between the casing joint ends (or liner joint ends) of the target well. This intermediate point will have a much lower magnetic signature, which increases and decreases as the casing joints (or liner joints) are approached, maxing out at the joint and reducing again as the casing joint (or liner joint) is passed. This results in a sinusoidal pattern while drilling nearby the target well. The magnetic field profile can be processed (for example, using sinusoidal curve fitting) to identify this sinusoidal pattern in the magnetic field profile and thus detect the nearby target well as depicted in FIG. **7**. Further processing can be configured to identify and characterize the magnitude and wavelength of the sinusoidal pattern in the magnetic field profile. The magnitude of the sinusoidal pattern representative of the target well can be used in combination with other known parameters (such as size of the wellbore being drilled) to determine field strength and distance to the target well. The wavelength of the sinusoidal pattern can be used in combination with other known parameters (such as the known distance between casing joints in the target well and the known RSS inclination angle and azimuth angle) to determine the direction (or interception angle) of the target well relative to the wellbore being drilled. The calculation of the distance and/or direction to the nearby target well can be calculated at or near real time and then used for real-time control of the direction of drilling of the wellbore. For example, processing can compute steering settings to ensure the required action (follow, avoid, or intercept the target well) is made. This processing can be repeated in real-time constantly to ensure a smooth drilling trajectory. In embodiments, the processing can account for formation tendencies, maximum DLS and tortuosity constraints. In the embodiments, the processing can be performed by a downhole system alone, such as part of the RSS or other downhole module, without requiring the drilling survey data to be processed at the surface. This processing can increase the speed of the drilling process, reduce downlinks, and/or ensure better control of the drilling trajectory. This processing can also allow wells to be drilled autonomously, even using the casing joints being counted from a parallel well to be a measure of downhole depth and thus provide for full closed loop drilling given a command to follow, intercept or avoid a nearby target well.

[0056] The methods and systems described herein can control the trajectory of the wellbore being drilled to avoid, follow or possibly intercept the target well. It can also allow for the detection of ghost target wells which may not be known previously and can now be avoided. Equally target wells which are not where they are expected to be due to poor surveying practices can also be detected and avoided before they cause a well collision problem.

[0057] It will be appreciated that the methods described herein may be configured for implementation via one or more controllers deployed downhole (e.g., in a rotary steerable tool or in an MWD tool). A suitable controller may include, for example, a programmable processor, such as a digital signal processor or other microprocessor or microcontroller and processor-readable or computer-readable program code embodying logic. A suitable processor may be utilized, for example, to execute the method embodiments (or various steps in the method embodiments) described herein. A suitable controller may also optionally include other controllable components, such as sensors (e.g., a temperature sensor), data storage devices, power supplies, timers, and the like. The controller may also be configured to be in electronic communication with the accelerometers and magnetometers, for example, as depicted herein. A suitable controller may also optionally communicate with other instruments in the drill string, such as, for example, telemetry systems that communicate with the surface. A suitable controller may further optionally include volatile or non-volatile memory or a data storage device.

[0058] FIG. **8** illustrates an example device **2500**, with a processor **2502** and memory **2504** that can be configured to implement various embodiments of the processes and systems as discussed in the present application. For example, various steps or operations of the processes or systems described herein can be embodied by computer program instructions (software) that execute on the device **2500**. Memory **2504** can also host one or more databases and can include one or more forms of volatile data storage media such as random-access memory (RAM), and/or one or more forms of nonvolatile storage media (such as read-only memory (ROM), flash memory, and so forth).

[0059] Device **2500** is one example of a computing device or programmable device and is not intended to suggest any limitation as to scope of use or functionality of device **2500** and/or its possible architectures. For example, device **2500** can comprise one or more computing devices, programmable logic controllers (PLCs), etc.

[0060] Further, device **2500** should not be interpreted as having any dependency relating to one or a combination of components illustrated in device **2500**. For example, device **2500** may include one or more computers, such as a laptop computer, a desktop computer, a mainframe computer, etc., or any combination or accumulation thereof.

[0061] Device **2500** can also include a bus **2508** configured to allow various components and devices, such as processors **2502**, memory **2504**, and local data storage **2510**, among other components, to communicate with each other.

[0062] Bus **2508** can include one or more of any of several types of bus structures, including a memory bus or memory controller, a peripheral bus, an accelerated graphics port, and a processor or local bus using any of a variety of bus architectures. Bus **2508** can also include wired and/or wireless buses.

[0063] Local data storage **2510** can include fixed media (e.g., RAM, ROM, a fixed hard drive, etc.) as well as removable media (e.g., a flash memory drive, a removable hard drive, optical disks, magnetic disks, and so forth). One or more input/output (I/O) device(s) **2512** may also communicate via a user interface (UI) controller **2514**, which may connect with I/O device(s) **2512** either directly or through bus **2508**.

[0064] In one possible implementation, a network interface **2516** may communicate outside of device **2500** via a connected network. A media drive/interface **2518** can accept removable tangible media **2520**, such as flash drives, optical disks, removable hard drives, software products, etc. In one possible implementation, logic, computing instructions, and/or software programs comprising elements of module **2506** may reside on removable media **2520** readable by media drive/interface **2518**.

[0065] In one possible embodiment, input/output device (s) **2512** can allow a user (such as a human annotator) to enter commands and information into device **2500**, and also allow information to be presented to the user and/or other components or devices. Examples of input device(s) **2512** include, for example, sensors, a keyboard, a cursor control device (e.g., a mouse), a microphone, a scanner, and any other input devices known in the art. Examples of output devices include a display device (e.g., a monitor or projector), speakers, a printer, a network card, and so on.

[0066] Various processes and systems of present disclosure may be described herein in the general context of software or program modules, or the techniques and modules may be implemented in pure computing hardware. Software generally includes routines, programs, objects, components, data structures, and so forth that perform particular tasks or implement particular abstract data types. An implementation of these modules and techniques may be stored on or transmitted across some form of tangible computer-readable media. Computer-readable media can be any available data storage medium or media that is tangible and can be accessed by a computing device. Computer readable media may thus comprise computer storage media. "Computer storage media" designates tangible media, and includes volatile and non-volatile, removable, and non-removable tangible media implemented for storage of information such as computer readable instructions, data structures, program modules, or other data. Computer storage media include, but are not limited to, RAM, ROM, EEPROM, flash memory or other memory technology, CD-ROM, digital versatile disks (DVD) or other optical storage, magnetic cassettes, magnetic tape, magnetic disk storage or other magnetic storage devices, or any other tangible medium which can be used to store the desired information, and which can be accessed by a computer.

[0067] Some of the methods and processes described above can be performed by a processor. The term "processor" should not be construed to limit the embodiments disclosed herein to any particular device type or system. The processor may include a computer system. The computer system may also include a computer processor (e.g., a microprocessor, microcontroller, digital signal processor, general-purpose computer, special-purpose machine, virtual machine, software container, or appliance) for executing any of the methods and processes described above.

[0068] The computer system may further include a memory such as a semiconductor memory device (e.g., a RAM, ROM, PROM, EEPROM, or Flash-Programmable RAM), a magnetic memory device (e.g., a diskette or fixed disk), an optical memory device (e.g., a CD-ROM), a PC card (e.g., PCMCIA card), or other memory device.

[0069] Alternatively or additionally, the processor may include discrete electronic components coupled to a printed circuit board, integrated circuitry (e.g., Application Specific Integrated Circuits (ASIC)), and/or programmable logic devices (e.g., a Field Programmable Gate Arrays (FPGA)). Any of the methods and processes described above can be implemented using such logic devices.

[0070] Some of the methods and processes described above can be implemented as computer program logic for use with the computer processor. The computer program logic may be embodied in various forms, including a source code form or a computer executable form. Source code may include a series of computer program instructions in a variety of programming languages (e.g., an object code, an assembly language, or a high-level language such as C, C++, or JAVA). Such computer instructions can be stored in a non-transitory computer readable medium (e.g., memory) and executed by the computer processor. The computer instructions may be distributed in any form as a removable storage medium with accompanying printed or electronic documentation (e.g., shrink wrapped software), preloaded with a computer system (e.g., on system ROM or fixed disk), or distributed from a server over a communication network (e.g., the Internet).

[0071] Although a surveying while drilling method and certain advantages thereof have been described in detail, it should be understood that various changes, substitutions and alterations may be made herein without departing from the spirit and scope of the disclosure. Additionally, in an effort to provide a concise description of these embodiments, not all features of an actual embodiment may be described in the specification. It should be appreciated that in the development of any such actual implementation, as in any engineering or design project, numerous embodiment-specific decisions will be made to achieve the developers' specific goals, such as compliance with system-related and business-related constraints, which may vary from one embodiment to another. Moreover, it should be appreciated that such a development effort might be complex and time consuming, but would nevertheless be a routine undertaking of design, fabrication, and manufacture for those of ordinary skill having the benefit of this disclosure.

[0072] Additionally, it should be understood that references to "one embodiment" or "an embodiment" of the present disclosure are not intended to be interpreted as excluding the existence of additional embodiments that also incorporate the recited features. For example, any element described in relation to an embodiment herein may be combinable with any element of any other embodiment described herein.

[0073] All numbers or values provided encompass numbers or values that are "about" equal to or equivalent to such number, unless the context specifically indicates a contrary interpretation. By way of example, a reference to 10% should be interpreted to be "about 10%" unless unambiguously described as exactly 10%. The term "about", as well as other terms of degree including “approximately”, “substantially”, and the like, represent an amount close to the stated amount that is within standard manufacturing or process tolerances, or which still performs a desired function or achieves a desired result. For example, the terms “approximately,” “about,” and “substantially” may refer to an amount that is within less than 5% of, within less than 1% of, within less than 0.1% of, and within less than 0.01% of a stated amount. Further, it should be understood that any directions or reference frames in the preceding description are merely relative directions or movements. For example, any references to “up” and “down” or “above” or “below” are merely descriptive of the relative position or movement of the related elements.

[0074] Although only a few example embodiments have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible in the example embodiments without materially departing from this invention. Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims. In the claims, means-plus-function clauses are intended to cover the structures described herein as performing the recited function and not only structural equivalents, but also equivalent structures. Thus, although a nail and a screw may not be structural equivalents in that a nail employs a cylindrical surface to secure wooden parts together, whereas a screw employs a helical surface, in the environment of fastening wooden parts, a nail and a screw may be equivalent structures. It is the express intention of the applicant not to invoke 35 U.S.C. § 112, paragraph 6 for any limitations of any of the claims herein, except for those in which the claim expressly uses the words ‘means for’ together with an associated function.

What is claimed is:

1. A method for drilling a subterranean wellbore, the method comprising:
- drilling the wellbore by rotating a bottomhole assembly (BHA), the BHA including a cutting tool and at least one sensor;
- acquiring measurements with the at least one sensor while drilling the wellbore;
- computing a magnetic field profile by processing the measurements acquired with the at least one sensor;
- processing the magnetic field profile to identify and characterize a signature or pattern in the magnetic field profile that is representative of a target well proximate to the wellbore being drilled; and
- computing at least one of a distance to the target well or a direction to the target well based on characteristics of the signature or pattern in the magnetic field profile.

2. The method of claim **1**, wherein:
- the at least one sensor comprises a triaxial accelerometer set and a triaxial magnetometer set.

3. The method of claim **2**, wherein:
- the at least one sensor further comprises at least one gyroscope.

4. The method of claim **1**, wherein:
- the signature or pattern in the magnetic field profile that is representative of the target well comprises a sinusoidal signature or pattern.

5. The method of claim **4**, wherein:
- the distance to the target well is based on magnitude of the sinusoidal signature or pattern in the magnetic field profile.

6. The method of claim **4**, wherein:
- direction to the target well is based on wavelength of the sinusoidal signature or pattern in the magnetic field profile.

7. The method of claim **1**, wherein:
- the signature or pattern in the magnetic field profile that is representative of the target well is defined by structural features of the target well.

8. The method of claim **7**, wherein:
- the structural features of the target well include the body and shoulders of casing joints or liner joints.

9. The method of claim **1**, wherein:
- the magnetic field profile is computed from the measurements of the at least one sensor at survey points of varying measured depth in the wellbore being drilled.

10. The method of claim **1**, wherein:
- the magnetic field profile includes a plurality of measured magnetic vectors as a function of measured depth along the wellbore axis.

11. The method of claim **10**, wherein:
- each measured magnetic vector of the plurality of measured magnetic vectors is represented by a magnitude and an orientation, wherein the magnitude is computed by subtracting contribution of the earth magnetic field from readings of a tri-axial magnetometer set, and wherein the orientation is determined from synchronous readings of a tri-axial accelerometer set.

12. The method of claim **1**, further comprising:
- using the computed distance or direction to the target well to control the direction of drilling of the wellbore.

13. The method of claim **12**, wherein:
- the direction of drilling of the wellbore is controlled to follow, intercept or avoid the target well.

14. The method of claim **12**, wherein:
- the BHA further comprises a rotary steerable drilling tool with a steering element; and
- the direction of drilling of the wellbore is adjusted based on the computed distance or direction to the target well and the direction of drilling of the wellbore is controlled by actuation of the steering element of the rotary steerable tool to change direction of drilling.

15. A system for drilling a subterranean wellbore, the system comprising:
- a bottomhole assembly (BHA) configured to drill the wellbore, wherein the BHA includes a cutting tool and at least one sensor, wherein the at least one sensor is configured to acquire measurements while drilling the wellbore; and
- a processor or controller configured to perform operations that include:
  - computing a magnetic field profile by processing the measurements acquired with the at least one sensor;
  - processes the magnetic field profile to identify and characterize a signature or pattern in the magnetic field profile that is representative of a target well proximate to the wellbore being drilled; and
  - computing at least one of a distance to the target well or a direction to the target well based on characteristics of the signature or pattern in the magnetic field profile.

16. The system of claim **15**, wherein:
- the at least one sensor comprises a triaxial accelerometer set and a triaxial magnetometer set.

17. The method of claim **15**, wherein:
the at least one sensor further comprises at least one gyroscope.

18. The system of claim **15**, wherein:
the signature or pattern in the magnetic field profile that is representative of the target well comprises a sinusoidal signature or pattern.

19. The system of claim **18**, wherein:
the distance to the target well is based on magnitude of the sinusoidal signature or pattern in the magnetic field profile.

20. The system of claim **18**, wherein:
direction to the target well is based on wavelength of the sinusoidal signature or pattern in the magnetic field profile.

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