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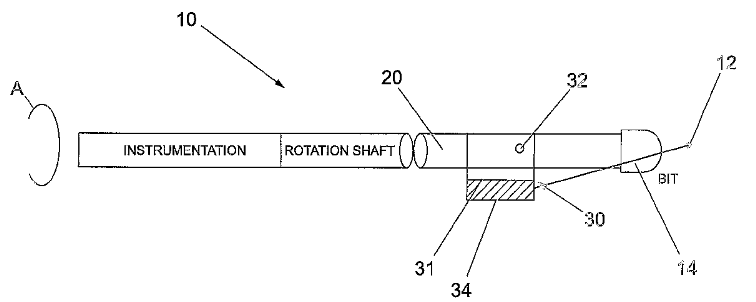
(54) **Title:** DETERMINATION OF DEVICE ORIENTATION



(57) **Abstract:** A method for measuring the orientation of an offset stabiliser device in a downhole environment, and a suitably modified device to enable this measurement, are disclosed. A shaft rotates relative to the stabiliser device, and signal trigger means are provided at known locations on each of the rotating shaft and the stabiliser device. When the signal trigger means on each component are brought into alignment, a signal is triggered. The signal trigger means could be a pair of apertures, which results in the generation of a pressure pulse, or a mechanical clapper assembly, which results in an acoustic signature. The timing of the generated signals are used together with the measured orientation of the shaft, obtained using an angular measurement sensor such as an accelerometer and/or magnetometer, in order to calculate the orientation of the offset stabiliser device.

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Determination of Device Orientation

The present invention relates to the determination of device orientation, in particular to a a downhole assembly and to a method of determining the orientation of a downhole device.

There are many situations where it is important yet difficult to measure the orientation of a device. In particular, in a drilling environment, when performing a drilling operation, the trajectory of a drill bit can be controlled by varying the angular position of an offset stabiliser device. In order to control the drilling process, it is therefore essential to know the orientation of the offset stabiliser device.

However, this is difficult and cumbersome to monitor. Conventionally, the drillstring has to be mechanically disengaged to enable the measuring of the stabiliser orientation, and then re-engaged again before drilling can be resumed. This process uses up a lot of time, adding to the difficulty and cost, and detracting from the efficiency of the overall drilling operation.

This effort, time and expenditure could be reduced if there was an effective way of making a remote measurement of the orientation of an offset stabiliser or similar orientation determination or steering device remote from the system.

According to a first aspect of the present invention, there is provided a downhole assembly as set out in the attached claim 1.

According to a second aspect of the present invention, there is provided a method of determining the orientation of a downhole device, as set out in the attached claim 22.

The present invention will now be described with reference to the accompanying drawings, in which:

Fig. 1 shows an assembly incorporating one embodiment of the present invention;

Fig. 2 illustrates the functioning of instrumentation used in the present invention; and

Fig. 3 shows a cross-sectional view of part of the assembly shown in Fig. 1.

Fig. 1 shows an assembly 10 where the trajectory 12 of a drillbit 14 is defined by the angular position of an offset stabiliser device 30 which will force the drillbit 14 in a particular direction. A sleeve 31 is mounted on a central rotating shaft 20 on bearings such that when the shaft 20 rotates the sleeve 31 remains relatively rotationally stable.

The sleeve 31 can have a slight offset 34 such that the offset 34 is positioned to force the drillstring 14 in a particular direction 12. It is therefore critical to understand the orientation of the sleeve offset 34 in order to determine the direction 12 in which the bit 14 is being pushed.

A directional measurement system is mounted on the rotating shaft 20 that includes measurement instruments to determine the rotational position of the shaft 20 relative to the earth's gravitational field, magnetic field or inertial rotational field. Alternatively, a resolver arrangement may be used to a known reference.

The measurement instruments used in a preferred embodiment of the present invention are a three axis accelerometer and three axis magnetometer assembly configured with X, Y and Z axes. The Z axis is defined as the axis along the tool string, the Y axis is aligned along the toolface datum, and the X axis is oriented such that the X, Y and Z axes form a set defining the directions of basis vectors to define position of the tool with respect to the earth's gravitational and magnetic fields.

The output of the accelerometer is expressed as a gravity function Gf, having components G_x, G_y, and G_z in the frame of reference. Gf is defined by:

$$gf(Gt, GTF, INC) = Gt\begin{pmatrix} -\sin(INC)\sin(GTF) \\ -\sin(INC)\cos(GTF) \\ \cos(INC) \end{pmatrix} \qquad \text{Eqn 1}$$

where Gt is the vector sum of the total gravity field, INC is the angle of inclination of the Z axis from the vertical, and GTF is a parameter called the Gravity Tool Face, defined as the angle between the Y axis and the projection of the earth's gravitational field vector onto the X-Y plane.

GTF is equivalent to the roll angle of the tool where the reference point or scribe line is in line with the Y-axis.

The output of the magnetometer is expressed as a magnetic function Hf, having components H_x, H_y, and H_z in the frame of reference. Hf is defined by equation 2, which is attached as an appendix to this description.

In equation 2, Ht is the vector sum of the total magnetic field, AZ is the magnetic azimuth relative to magnetic north, and DIP is the angle down to the earth's magnetic field vector from its projection on the horizontal azimuth.

The above outputs can be algebraically manipulated to obtain measurements that correspond to the rotational position of the rotating shaft 20.

The first of these is the accelerometer toolface, or ATF. This has the same definition as the variable GTF as defined above, and is defined as the arctangent of (G_x/G_y).

The second of these measurements is the magnetic toolface, or MTF. This is defined as the angle between the H_y axis and the projection of the earth's magnetic field vector onto the X-Y plane. In a manner similar to ATF, MTF is measured with the H_y axis aligned to the scribe line. MTF is defined as being the arctangent of (H_x/H_y).

The final of these parameters is the toolface azimuth, MTA. This is the angle between the North axis and the projection of the tool's Y-axis onto the N-E plane, i.e. MTA is the direction that the scribe line is pointing to in terms of the azimuth. MTA is defined by:

MTA=(Gx*Hz + Gz*Hx)*SQRT(Gx*Gx + Gy*Gy + Gz*Gz)/(Hy*(Gx*Gx + Gz*Gz) + Gy*(Gz*Hz-Gx*Hx). (eqn. 3)

It will be apparent to those skilled in the art that as an alternative to measuring the magnetic field vectors, gyroscopic instruments could be used to measure earth's rotation vectors , and, using similar transforms, angular measurements based on inertial measurements could be made. Both these methods, or any other suitable method for determining the orientation of the rotating shaft, are incorporated within the scope of the present invention.

Fig. 2 shows the instrumentation used to convert the raw data obtained from the accelerometer and magnetometer into the form described above. As the shaft 20 is continuously rotating, the respective toolface measurements will change depending on the sampling frequency and rotational position of the shaft 20.

When measuring and processing the signals from the accelerometer and magnetometer, it is important that the respective data input channels are phase matched such that the measurement point in time for each sample is the same. This can be achieved either through synchronous sampling or through calibration of the system.

During drilling operations, in particular during rotation, there is a trade-off between resolution of accelerometers and dynamic range. While rotating, due to the accelerations observed the accelerometer channels may saturate. This situation can, in certain circumstances cause non liberties and errors in the tool face or orientation calculation.

A method used to resolve this problem is to make periodic static measurements of the Gx, Gy, Gz and Hx, Hy, Hz axis.

Using the static measured values, AZ, INC, DIP, GTF, MTF, SLA and Ht can be calculated, where the term "SLA" is defined as MTA.

By geometric definition, and by examining equation 2, it is observed that AZ is the angle between GTF and MTF. It is therefore concluded that by using the static measured AZ value and the MTF value obtained dynamically while rotating, which is a magnetic measurement and relatively immune to noise, saturation and vibration effects, the GTF or desired tool face orientation can be measured using MTF measurements.

The above is a valid approximation provided substantial changes are not made between successive static measurements, which is typically the case during the requisite operations.

The present invention uses the continuous sampling of toolface information combined with a second measurement to determine the position of the non-rotating sleeve.

The second measurement is provided by a signal trigger means, at least one of which is provided at a known location on each of the rotating drill shaft and the offset stabiliser device.

In a first embodiment of the present invention, the signal trigger means comprises apertures, which when aligned, define a through-passage that results in a pressure pulse being generated.

In this embodiment, the non-rotating sleeve and rotating shaft are designed such that each has a hole through the sidewall. When the central shaft 20 rotates and the two holes line up, fluid or gas moves from the high-pressure centre bore to the lower pressure outer bore. The effect of this fluid or gas flow is to effect a negative pressure pulse in the bore and a positive pulse in the annulus.

Fig. 3 shows this in more detail. A rotating mandrel 60 has a pre-load ring 62 attached thereto such that they rotate together. The device 30 comprising the non-rotating stabiliser is attached to a borehole wall with knifed blades (not shown). Apertures 64, 66, and 68 are provided in the stabiliser device 30, the pre-load ring 62 and mandrel 60 respectively.

The components illustrated in Fig. 3 are circular in cross-section.

The drillstring contains matter that is flowing therein at a different pressure to the pressure of the well-bore. The pressure of the drillstring is normally higher than the pressure of the well-bore, such that when the orifice of the preload ring is aligned with the orifice of the non-rotating stabiliser, fluid passes from the tool out to the well-bore, causing a negative pressure pulse in the drill string.

It is to be understood that the detected pressure pulse may also be either a negative or positive pulse in the annulus or bore, or a combination of such pulses.

A jet nozzle 70 is provided between the apertures 66 and 68 of the pre-load ring 62 and mandrel 60 to help control the flow rate of matter between the drillstring and the well-bore.

In a second embodiment of the present invention, the signal trigger means comprises a striking member and a resounding member, which when brought into alignment cause an acoustic signal to be transmitted.

The non-rotating sleeve and rotating shaft are designed such that one has a striking mechanism and one has an activating mechanism such that when the central shaft rotates and the striking mechanism lines up with the activation mechanism mechanical energy is transferred causing the striking mechanism to strike. The effect of this strike is to excite an acoustic wave which travels up the device through the drillstring to the detection device further up in the drill string.

A number of features of the invention will now be described, which are applicable to both embodiments unless otherwise stated.

The generated signal, hereinafter referred to generally as a pulse, is detected by a pressure sensor or an acoustic sensor, which in a preferred embodiment of the invention is located in the centre of the rotating shaft, although it will be appreciated that the pressure or acoustic sensor could be located in any suitable location either in the bore of the central shaft 20 or the annulus of the offset device 30. In the first embodiment, a strain gauge sensor could be used rather than a pressure sensor.

The pressure or acoustic signal is fed out through an exit port, which can utilise different shaped plates or covers so that the system is customised for different users. Changing the profile of the exit port will result in the compression or extension of the pressure or acoustic signal, and a user's software and acoustic signal or pressure detection routines can be adjusted as such after simple flow loop testing using various exit port profiles.

The pulse is used to synchronise or to trigger the sampling of the instrumentation system such that the appropriate rotational toolface measurement described above is identified and the position of the non-rotating sleeve determined.

The signal trigger means are at known locations on the rotating shaft 20 and on the stabiliser device 30, and so when the orientation of the shaft 20 is detected at the time of the pressure or acoustic pulse, this can be used to infer the orientation of the stabiliser device 30.

The accuracy of the measured tool face position can be increased by taking averages of the calculated position synchronised with pressure or acoustic pulses over a period of time.

Further techniques that can be used to increase the accuracy of the measured tool face position include using a Kalman Filtering technique or other associated Least Squares error technique to determine position and establish positional movement trends.

Furthermore, more than one set of corresponding apertures can be provided, so that more than one pulse is generated per revolution of the shaft. The data generated by these extra pulses helps decrease the errors in reading the signals.

Referring to Fig. 2, the inputs 40 representing each component of the outputs from the accelerometer and magnetometer, together with inputs 42 representing ground and 44 representing temperature, are fed into a low pass filter 46 before being passed on to a first analogue to digital converter 48. Outputs 50, 52 from pressure or acoustic signal sensors (described below) are input into a second analogue to digital converter 54. Outputs from both the A-D converters 48, 54 are input to a processor 56, which produces an output 58.

Instead of using a low pass filter, a A-D convertor and zero phase digital filter could be used.

The output 58 shows the relevant angles, pressure signals, and synchronises the angle measurements with the pressure or acoustic measurements.

As with any hydraulic system, noise or erratic pulses are present. The particular pulse generated by the alignment of the two signal triggers is modelled and determined using a correlation detection technique that uses prior knowledge of the pulse shape and profile along with data from the instrumentation, in order to correct for the rotational speed of the drillpipe. The measured pulse is correlated with a confidence level to the expected measurement and a probability measure estimated and used in performance enhancement.

Using this method means that a single set of instrumentation can be adapted to be used for many different orientation systems or remote signalling systems and with the correlation detection system used to discriminate which measurement applies to which signal, the result is that a plethora of devices can be used for measuring and signalling to the remote instrumentation if required.

The present invention can not only be used for drilling systems, it has applications for determining the position of casing outlets in multilateral systems and for orienting completion systems in a number of downhole applications. The present invention can be applied to bottom hole assemblies whether comprised of drill collars and traditional components as well as to drilling assemblies comprised of casing, tubulars, or any combination of casing and downhole drilling collars or tools.

Yet another application of this invention is that the downhole rate of rotation of the moveable member can be determined by measuring the frequency of the pulses that are generated. This can be calculated at the downhole tool and transmitted uphole, or a surface system could monitor the pulses and derive the downhole RPM therefrom.

The angular position and the rate of change of angular position can be utilised in a servo, actuation or control feedback arrangement whereby a system drives the offset sleeve counter clockwise to retain a predetermined position, most suitably at a rate determined from the measurement.

Furthermore, differentiation of the rate measurement yields information relating to acceleration aspects of the moveable member. Both these measurements provide valuable information relating to movement of the non rotating sleeve and information relating to how efficiently the rotating member is moving in the borehole and if sticking and slipping of the bit and rotating member is a problem. For example a downhole sample with wide distribution would be indicative of stick slip. Changes in rotary RPM, weight, or mud additives might be employed to eliminate this destructive condition.

In the first embodiment, the use of the pressure measurements in both the bore and in the annulus can greatly improve the performance of the system in terms of signal to noise ratio. In particular, performing a bore annulus differential measurement can yield an improved signal to noise ratio.

Additionally, noise generated by a second pulsing system used for example to transmit data to the surface can be subtracted from the signal received at the detection system by using a common microcontroller or DSP to control both systems and having knowledge when pulsing to the surface is taking place. Additionally the correlation methods described previously can be used to discriminate between the various pulse types.

In a still further aspect of the invention, the exit port pressure pulse (or acoustic signal) and either of the bore or annular pressure transducer (or acoustic sensor) can be used to send data from the surface to the down hole tool.

This is achieved in a number of possible ways. Firstly the drill string rotation can be modulated. Altering the drill string RPM changes the pulse frequency and by sending a pre-determined sequence a message can be transferred from the surface to a down hole tool.

With respect to the first embodiment, at a given flow rate there will be a known pressure drop below the tool and therefore a known exit port pulse height. By varying the flow rate this pulse height will change, for example a 25% change in flow rate would generate a similar change in pressure pulse height. By cycling the pumps at surface in a predetermined sequence an encoded message can be transmitted to the down hole system.

This form of down linking (in either embodiment) could be used, for example, to instruct the tool to retract its angled blades, thus negating the eccentric effect of the offset sleeve and facilitate drilling a non-curved borehole.

The invention also enables a deflection device to be constructed, which comprises a decoupling device which in one configuration could be a knuckle or ball joint assembly, a decentring device which in one form could be an eccentric stabilizer, combined with a downhole power system which in one form would be a mud motor. These elements combined would result in a deflection device which would work while the entire device is rotated. This combination would allow the pipe to be rotated while making hole azimuth or inclination changes. This rotation improves hole cleaning by assisting in keeping the cuttings from the drilling operation in suspension and by minimizing well bore wall friction acting on the drilling string, these effects improve drilling efficiencies. These elements can be attached directly to the motor or its elements or can be more remotely connected as may be the case where the drilling string may be casing and the motor would be housed within the casing above the rotary deflection device which may be positioned closer to the bit.

It is also found that spectral analysis of the pressure pulse waveforms measured in the bore and in the annulus yields information relating to the gas content of the respective fluids. Typically, if the gas content is high the effect is to attenuate and slow down high frequencies, performing a spectral analysis of the bore and annular pressure pulse signals and comparing the spectral amplitudes will yield information relating to the change in gas or air content. This additional information can be used as a quantitative measure of gas influx into the wellbore and be used as a wellbore control measurement.

A further method to improve the signal detection in the first embodiment is to use a bore to annulus differential pressure sensor. This enables a measurement of the pulse to me made without a high background hydrostatic pressure measurement.

Improvements and modifications can be made to the above without departing from the scope of the invention.

Appendix: Equation 2

$$hf(Ht, DIP, AZ, INC, GTF) := Ht \cdot \begin{bmatrix} \cos(DIP)\cdot\sin(AZ)\cdot\cos(GTF)+\cos(DIP)\cdot\cos(AZ)\cdot\cos(INC)\cdot\sin(GTF)-\sin(DIP)\cdot\sin(INC)\cdot\sin(GTF) \\ \cos(DIP)\cdot\cos(AZ)\cdot\cos(INC)\cdot\cos(GTF)-\sin(DIP)\cdot\sin(INC)\cdot\cos(GTF)-\cos(DIP)\cdot\sin(AZ)\cdot\sin(GTF) \\ \sin(DIP)\cdot\cos(INC)+\cos(DIP)\cdot\cos(AZ)\cdot\sin(INC) \end{bmatrix}$$

CLAIMS

1. A downhole assembly comprising:

a device and a movable member capable of moving relative to the device;

orientation measurement means capable of obtaining a first set of readings representative of the orientation of the movable member; and

at least one signal trigger means provided at a known location on each of the device and movable member to generate a signal upon alignment.

2. The assembly of claim 1, wherein the orientation measurement means comprises at least one angular measurement sensor.

3. The assembly of claim 2, wherein the angular measurement sensor is capable of calculating the orientation of the toolface of the movable member with respect to the earth's magnetic field components and/or the earth's gravity field components.

4. The assembly of any of claims 1-3, further comprising calculation means capable of determining the orientation of the device based on the time or frequency of the signal, the known locations of the signal trigger means, and the first set of readings.

5. The assembly of any of claims 1-4, wherein the device and the movable member comprise coaxial

cylindrical portions which rotate relative to each other.

6. The assembly of any preceding claim, wherein a plurality of signal trigger means are provided on at least one of the movable member and device, such that a plurality of signals are generated by the signal trigger means upon movement of the movable member through part of or through a complete cycle.

7. The assembly of any preceding claim, further comprising a servo, actuation or control mechanism suitable to move the device to a predetermined orientation.

8. The assembly of any preceding claim, further comprising a deflection device which comprises a decoupling device, a decentering device, and a downhole power system.

9. The assembly of claim 8, wherein the decoupling device comprises a knuckle or ball joint assembly, the decentering device comprises an eccentric stabiliser, and the downhole system comprises a mud motor.

10. The assembly of any preceding claim, wherein the movable member is a rotating drill shaft, and the device is an offset stabiliser device, and the assembly is a drillstring.

11. The assembly of any of claims 4-10, wherein the calculation means comprises electronic signal processing means comprising signal sampling means, signal digitising means, and a central processing unit or digital signal processor.

12. The assembly of claim 11, wherein the calculation means comprises a phase matched low pass filter or A-D convertor and zero phase digital filter.

13. The assembly of any preceding claim, wherein the signal generated comprises measurable changes in an electric current.

14. The assembly of any preceding claim, wherein the signal generated comprises measurable changes in a magnetic field.

15. The assembly of any of claims 1-12, wherein the signal trigger means comprises apertures at known points on each of the device and the movable member, such that upon alignment of the apertures, a through-passage is provided between a point outside the assembly and a point within the inner of the device or movable member, and the signal comprises a pressure pulse created by a pressure differential which acts to move a medium through the apertures.

16. The assembly of claim 15, wherein the medium comprises gas, fluid, drilling muds or similar matter.

17. The assembly of claim 15 or claim 16, further comprising a pressure sensor located in at least one of the device and the movable member.

18. The assembly of claim 17, wherein the pressure sensor comprises a bore pressure transducer.

19. The assembly of claim 17, wherein the pressure sensor comprises an annulus pressure transducer.

20. The assembly of any of claims 1-12, wherein the signal trigger means comprises a striking member provided at one of the movable member and the device, and a resounding member provided at the other of the movable member and the device, such that when the striking member and resounding member are brought into alignment, the signal generated comprises an acoustic signature.

21. The assembly of claim 20, further comprising a listening device suitable to detect the acoustic signature.

22. A method of determining the orientation of a downhole operations device, the device being part of an assembly which also comprises a movable member which moves relative to the device, and wherein each of the device and the movable member has at least one signal trigger means provided at a known location thereon, the method comprising the steps of;

determining the orientation of the movable member; and

moving the movable member relative to the device, to generate a signal upon alignment of the signal trigger means.

23. The method of claim 22, wherein the step of determining the orientation of the movable member comprises using an accelerometer and a magnetometer.

24. The method of claim 23, comprising the step of using the accelerometer and magnetometer to calculate the orientation of the toolface of the movable member with respect to the earth's magnetic field vector and/or the earth's gravity vector.

25. The method of any of claims 22-24, further comprising determining the orientation of the device based on the time of the signal, the known locations of the signal trigger means, and the orientation of the movable member.

26. The method of any of claims 22-25, wherein the step of moving the movable member relative to the device comprises a rotation about a common axis.

27. The method of any of claims 22-26, further comprising the steps of providing a plurality of signal trigger means on at least one of the movable member and device, and generating a plurality of signals upon completion of one cycle of movement of the movable member.

28. The method of any of claims 22-27, further comprising the step of making periodic static measurements of the gravity function and magnetic function, and using these static measurements for determining the orientation of the device in situations where data channels of the accelerometer or magnetometer are saturated.

29. The method of any of claims 22-28, further comprising the step of taking averages of the calculated position over time.

30. The method of any of claims 22-29, further comprising the step of applying a Kalman filtering technique or least squares error technique to determine positional trends of the device.

31. The method of any of claims 22-30, further comprising performing a correlation detection technique to remove noise from the detected signal.

32. The method of any of claims 22-31, further comprising using a servo mechanism to move the device to a predetermined orientation.

33. The method of any of claims 22-32, further comprising the step of deflecting a device using a decoupling device, a decentering device, and a downhole power system.

34. The method of claim 33, wherein the decoupling device comprises a knuckle, the decentering device comprises an eccentric stabiliser, and the downhole system comprises a mud motor.

35. The method of any of claims 22-34, wherein the movable member is a rotating drill shaft, and the device is an offset stabiliser device, and the assembly is a drillstring.

36. The method of any of claims 22-35, wherein the step of determining the orientation of the device comprises the steps of sampling and digitising the signal, and outputting the signal to a central processing unit or digital signal processor.

37. The method of claim 36, wherein the step of determining the orientation of the device further comprises passing the signal through a phase matched low pass filter before digitising and outputting the signal.

38. The method of any of claims 22-37, wherein the step of generating a signal comprises the step of changing an electric current.

39. The assembly of claims 22-38, wherein the step of generating a signal comprises the step of changing a magnetic field.

40. The method of any of claims 22-37, wherein the signal trigger means comprises apertures at known

points on the surfaces of each of the device and the movable member, and wherein the step of moving the movable member relative to the device to generate a signal upon alignment of the signal trigger means comprises the step of;

bringing the apertures into alignment to provide a through-passage between a point outside the assembly and a point within the inner of the device or movable member, which generates a pressure pulse created by a pressure differential which acts to move a medium through the apertures.

41. The method of claim 40, wherein the medium comprises gas, fluid, drilling muds or similar matter.

42. The method of claim 40 or claim 41, further comprising the step of sensing pressure at a point in at least one of the device and the movable member.

43. The method of claim 42, wherein the pressure sensing step utilises a bore pressure transducer.

44. The method of claim 42, wherein the pressure sensing step utilises an annular pressure transducer.

45. The method of any of claims 40-44, further comprising the step of varying the flow rate down the drillstring to modify the magnitude of the generated pressure pulse.

46. The method of any of claims 40-44, further comprising the step of modulating the drillstring rotation to modify the magnitude of the generated pressure pulse.

47. The method of claim 45 or claim 46, further comprising the step of using the modified pressure pulse as a signal that is sent from a surface to a downhole operations tool.

48. The method of any of claims 22-37, wherein the signal trigger means comprises a striking member provided at one of the movable member and the device, and a resounding member provided at the other of the movable member and the device, and wherein the step of moving the movable member relative to the device to generate a signal upon alignment of the signal trigger means comprises the step of bringing the striking member and resounding member into alignment to generate an acoustic signature.

49. The method of claim 48, further comprising detecting the acoustic signature utilising a listening device.

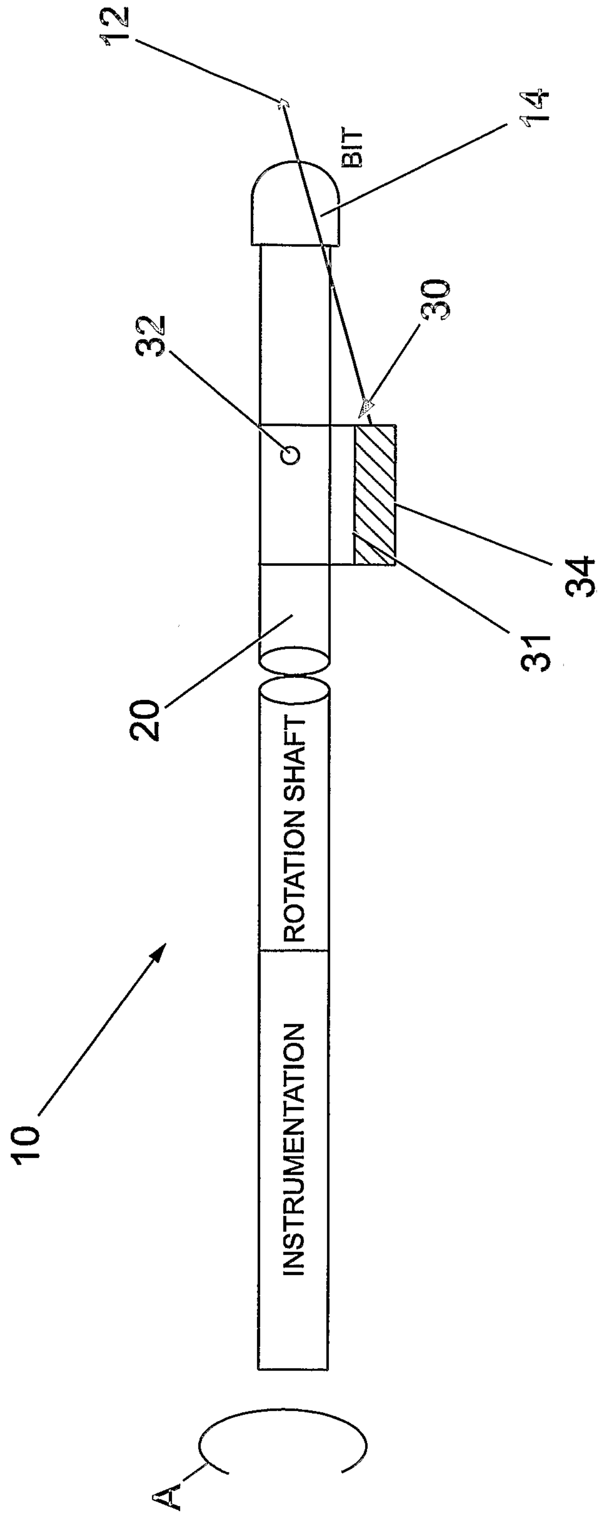

Fig. 1

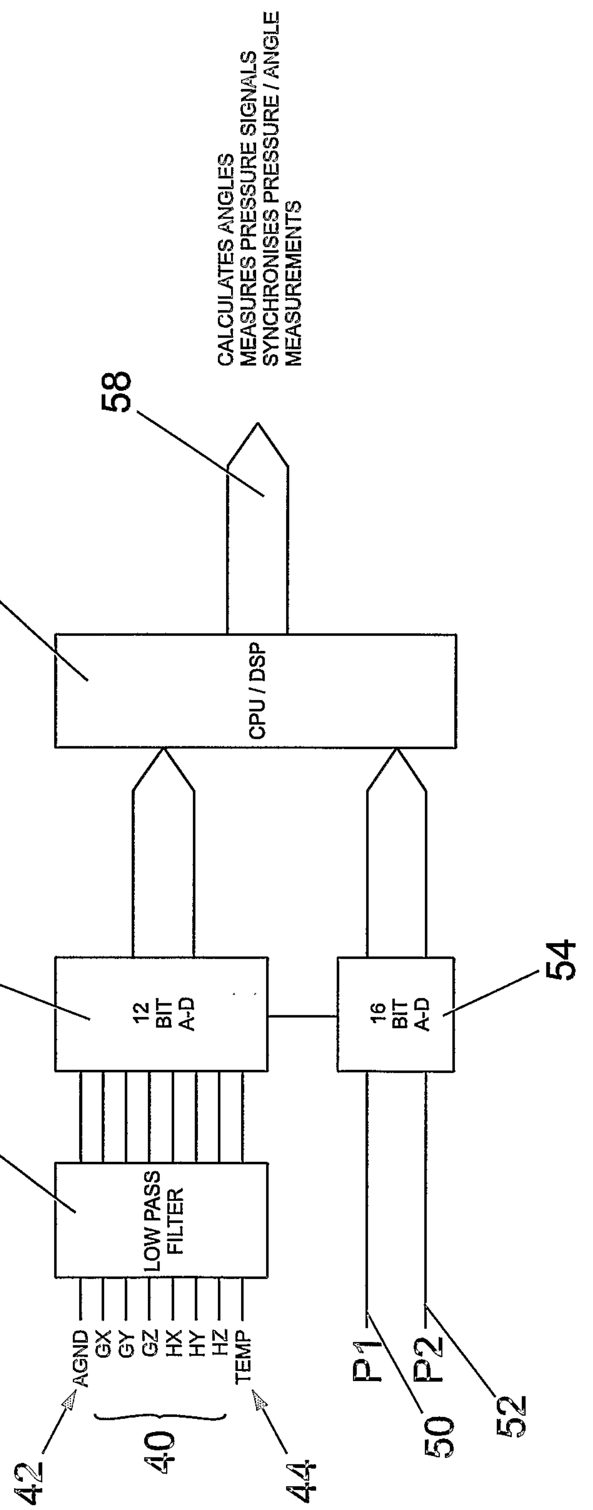
CALCULATES ANGLES
MEASURES PRESSURE SIGNALS
SYNCHRONISES PRESSURE / ANGLE
MEASUREMENTS
58
56
CPU / DSP
48
12
BIT
A-D
16
BIT
A-D
54
46
LOW PASS
FILTER
AGND
GX
GY
GZ
HX
HY
HZ
TEMP
42
40
44
P1
P2
50
52

Fig. 2

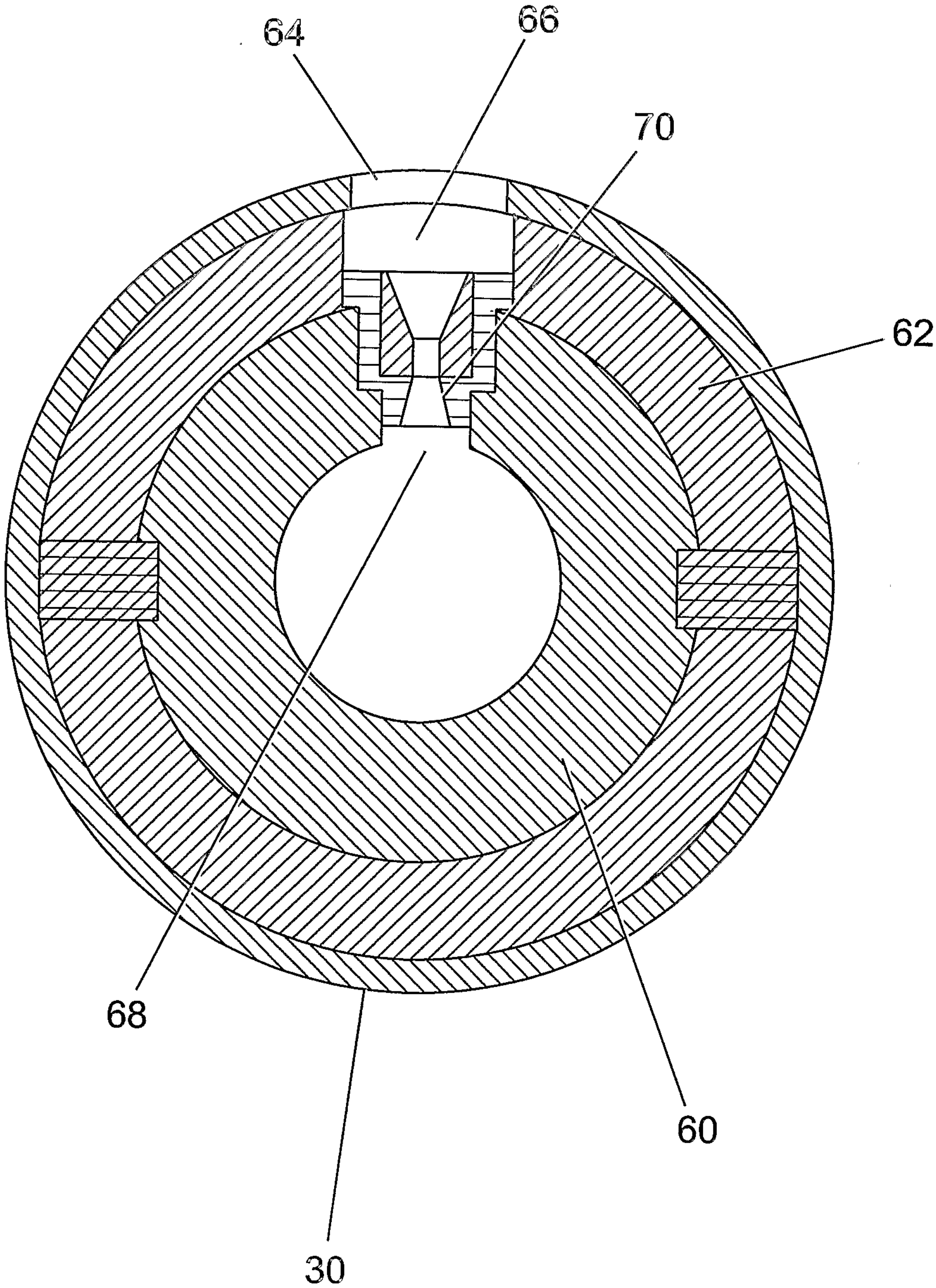

Fig. 3