US 20160305232A1

(19) United States
(12) Patent Application Publication
(10) Pub. No.: US 2016/0305232 A1
(43) Pub. Date: Oct. 20, 2016
Bird et al.

(54) SYSTEM AND METHOD FOR MONITORING TOOL ORIENTATION IN A WELL

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(21) Appl. No.: **15/133,765**

(22) Filed: **Apr. 20, 2016**

Related U.S. Application Data

(63) Continuation-in-part of application No. 14/698,516, filed on Apr. 28, 2015.

(60) Provisional application No. 62/149,922, filed on Apr. 20, 2015.

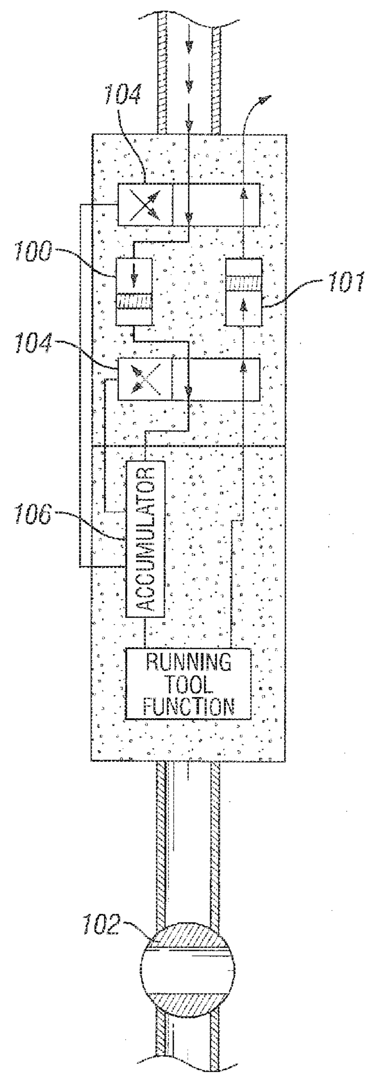
Publication Classification

(51) **Int. Cl.**
E21B 47/00 (2006.01)
E21B 33/043 (2006.01)
E21B 33/038 (2006.01)

(52) **U.S. Cl.**
CPC ***E21B 47/0001*** (2013.01); ***E21B 33/038*** (2013.01); ***E21B 33/043*** (2013.01)

(57) **ABSTRACT**

A system for monitoring equipment in an oil well, the system including a first sensor attached to a first well component, a second sensor attached to a second well component, a transducer attached to one of the first or the second sensors, for generating a pulse, a transceiver for measuring parameters of the pulse generated by the transducer, and a processor in communication with the transceiver that receives information about parameters of the pulse as measured by the transceiver.



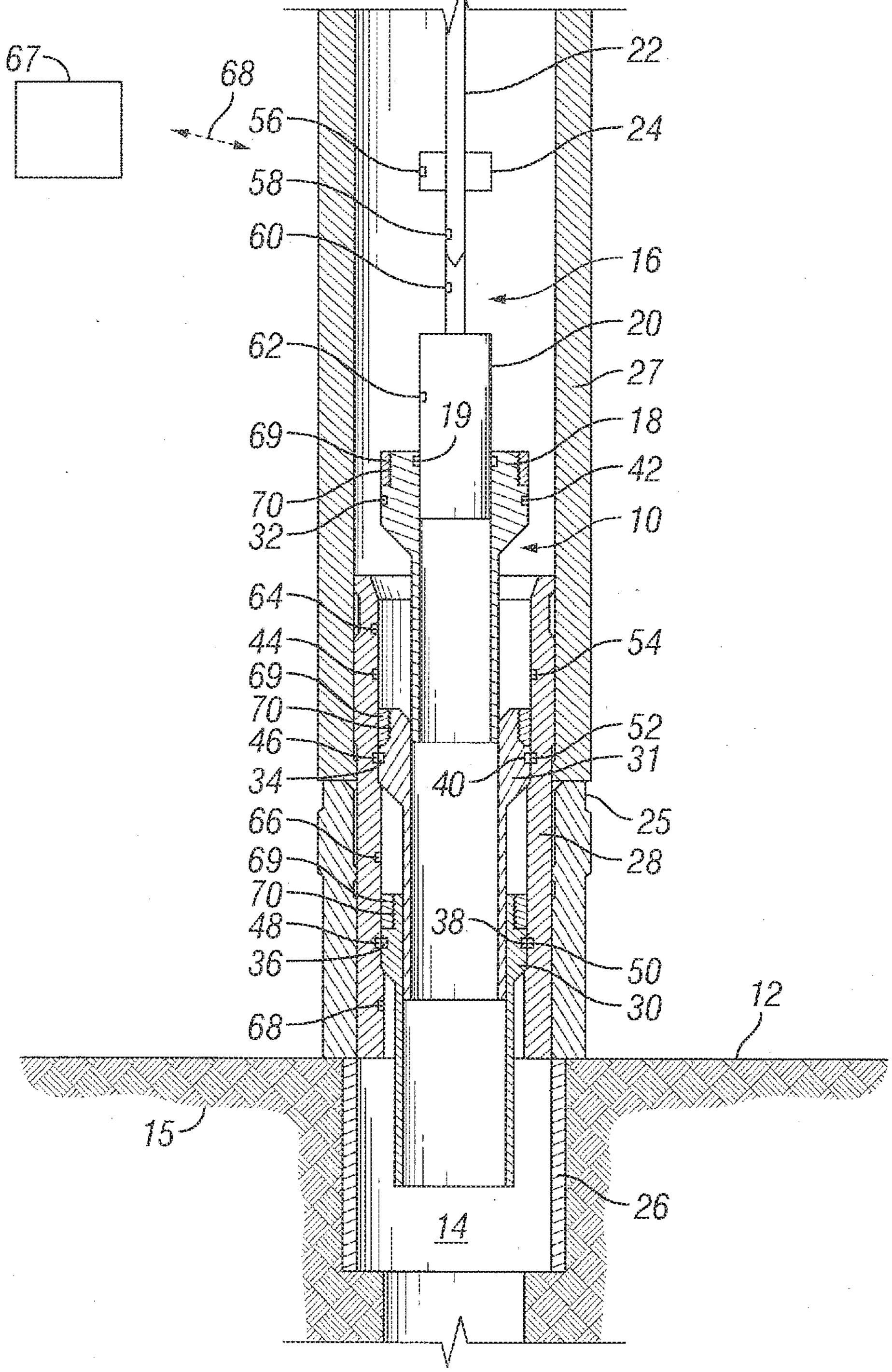

67
68
56
58
60
62
69
70
32
64
44
69
70
46
34
66
69
70
48
36
68
22
24
16
20
27
19
18
42
10
54
52
31
40
25
28
38
50
30
12
15
14
26

FIG. 1

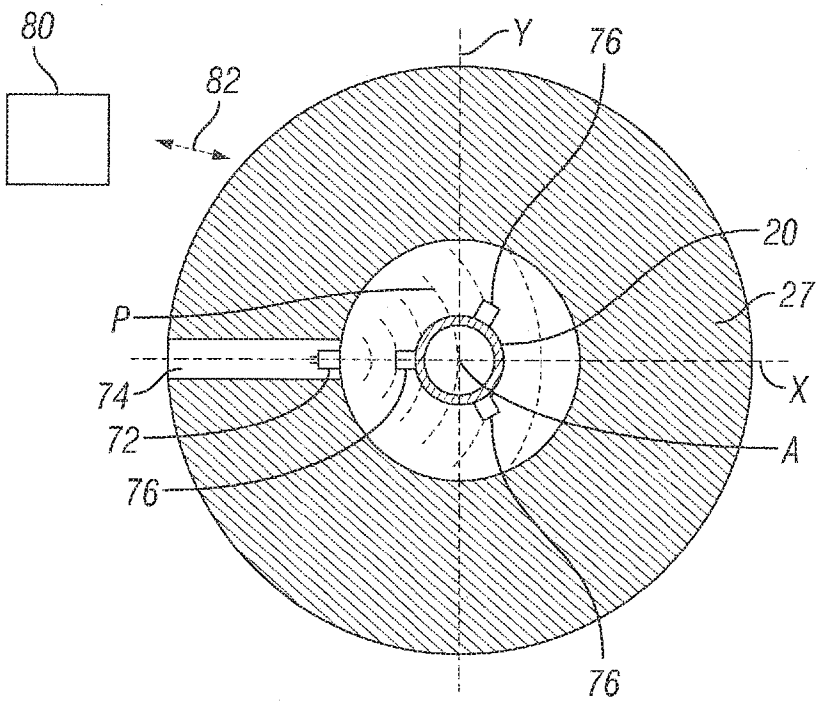

80
82
Y
76
20
27
P
74
72
76
X
A
76

FIG. 2

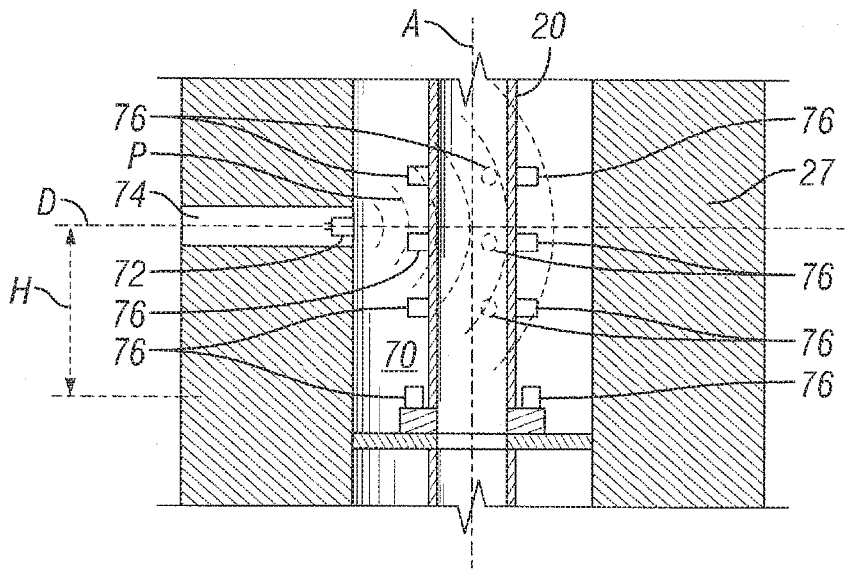

A
20
76
P
74
D
72
H
76
76
70
76
27
76
76
76

FIG. 3

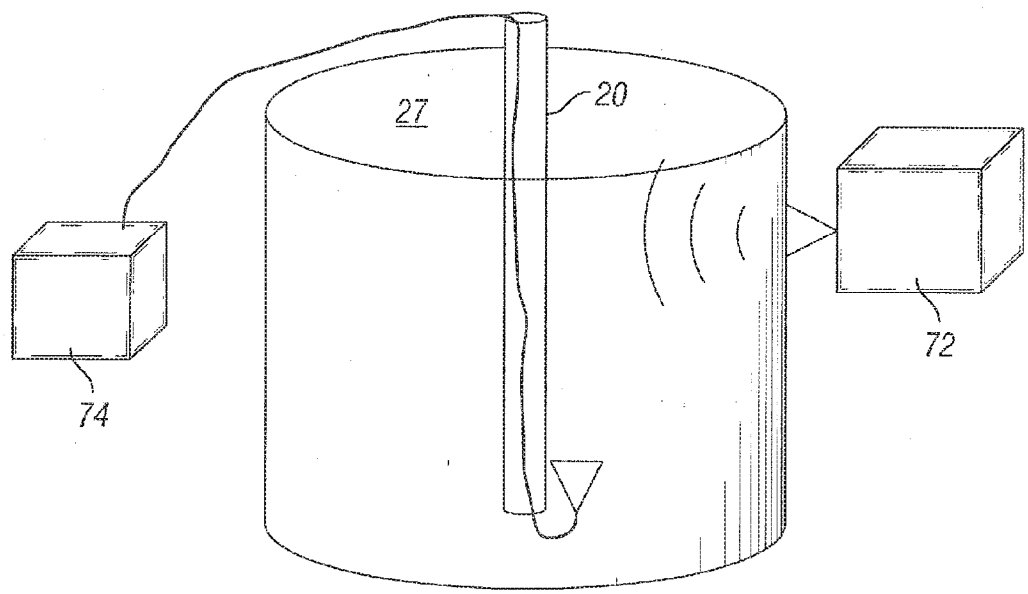


FIG. 4

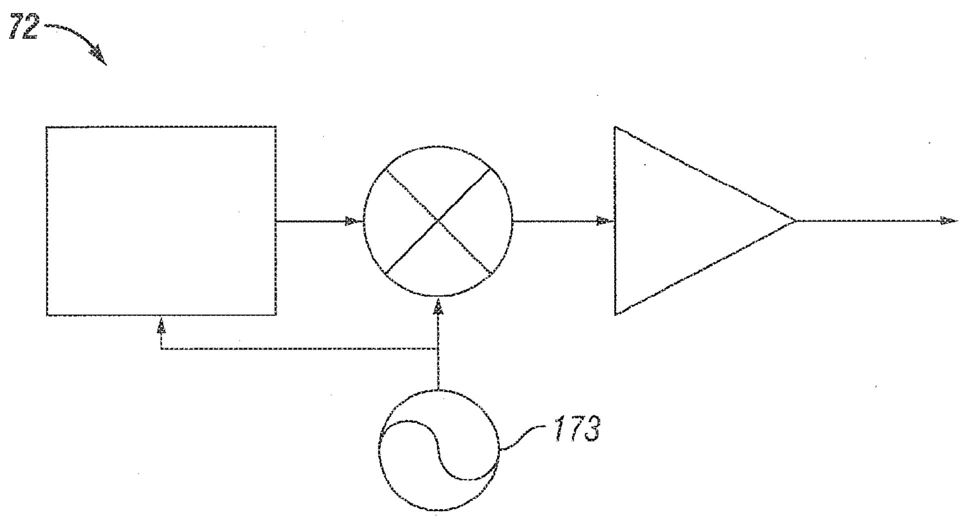


FIG. 5

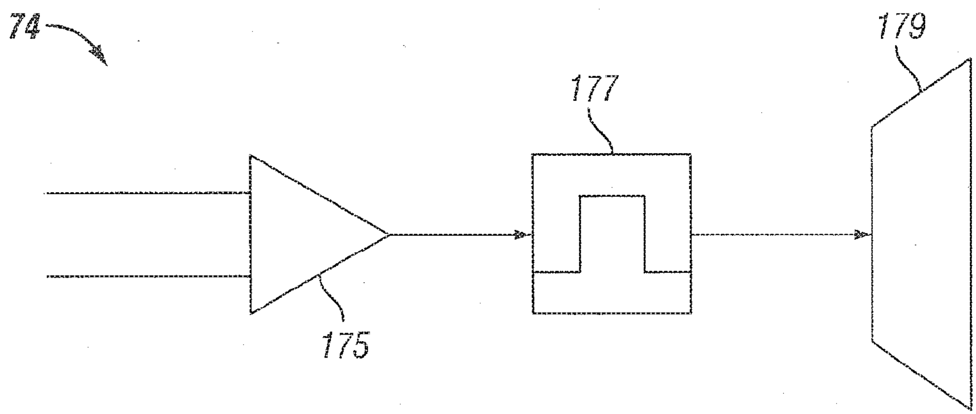


FIG. 6

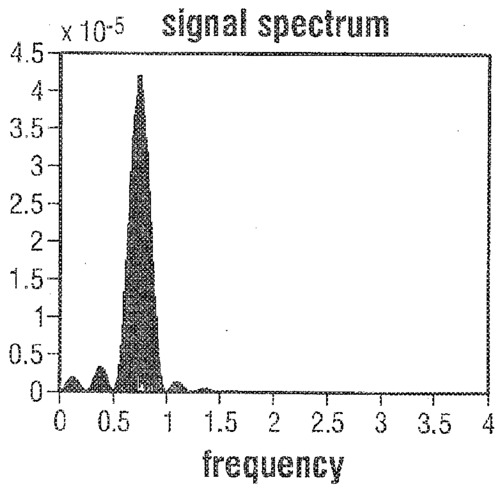


FIG. 7A

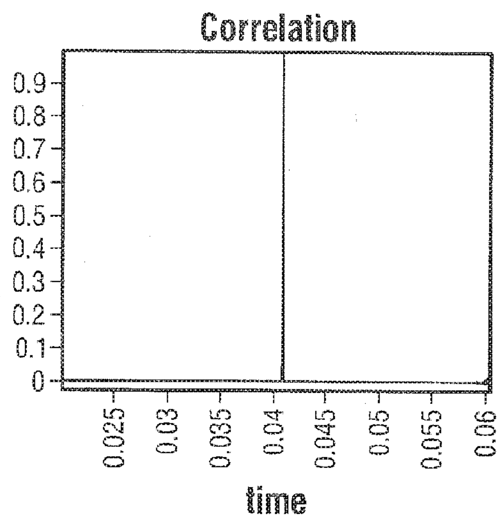


FIG. 7B

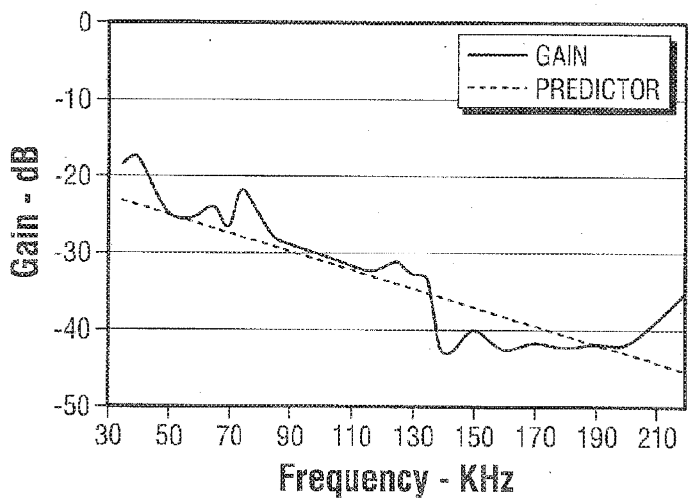


FIG. 8

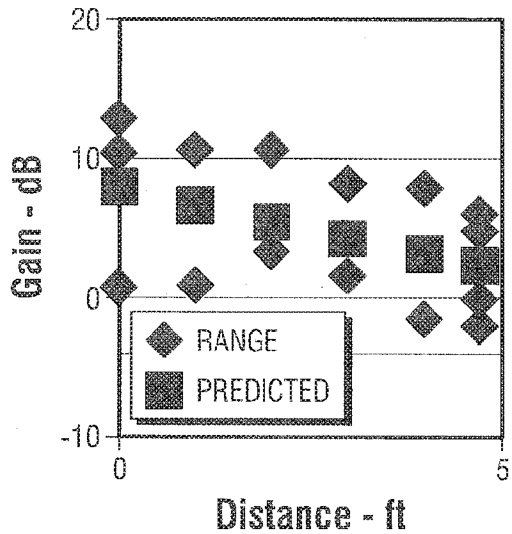

20
10
0
-10
Gain - dB
0
5
Distance - ft
RANGE
PREDICTED

FIG. 9

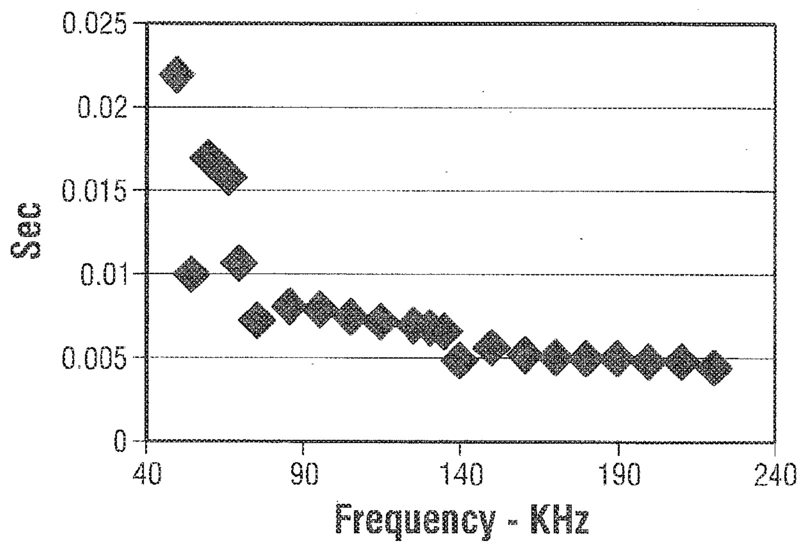

0.025
0.02
0.015
0.01
0.005
0
Sec
40
90
140
190
240
Frequency - KHz

FIG. 10

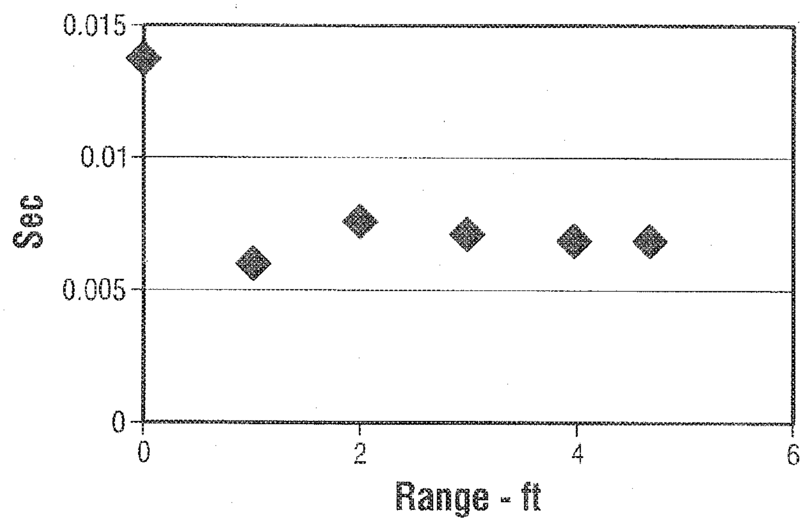

0.015
0.01
0.005
0
Sec
0
2
4
6
Range - ft

FIG. 11

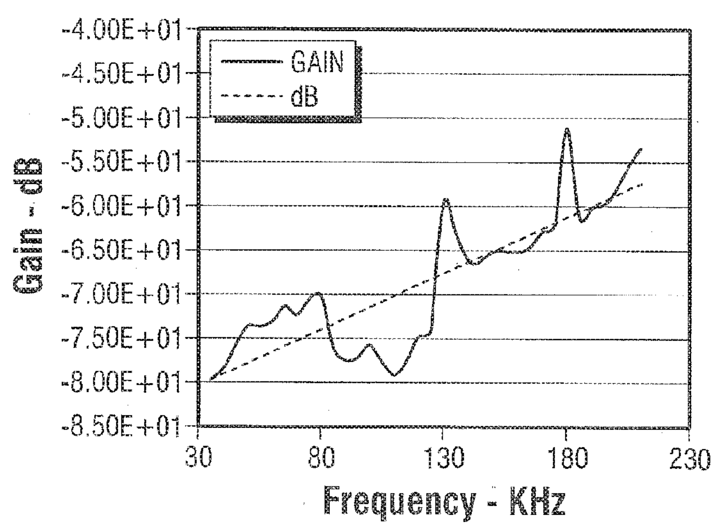

-4.00E+01
-4.50E+01
-5.00E+01
-5.50E+01
-6.00E+01
-6.50E+01
-7.00E+01
-7.50E+01
-8.00E+01
-8.50E+01
Gain - dB
GAIN
dB
30
80
130
180
230
Frequency - KHz

FIG. 12

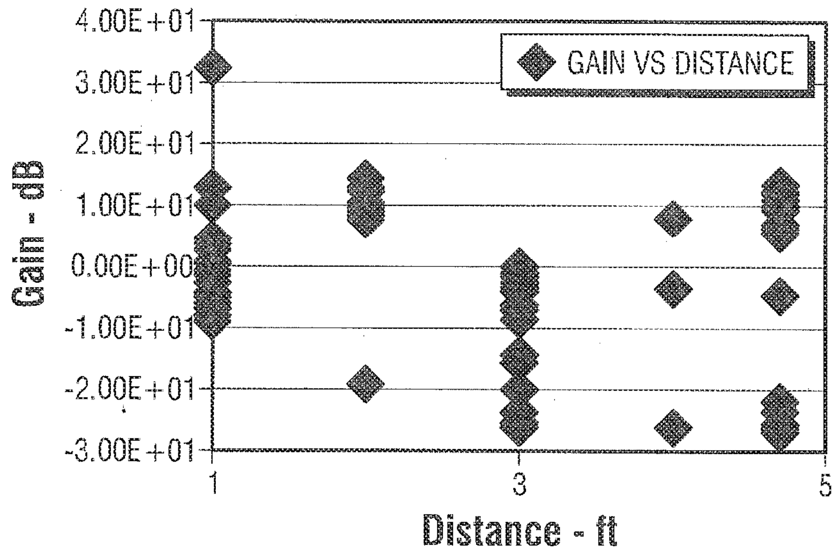

GAIN VS DISTANCE
Gain - dB
4.00E+01
3.00E+01
2.00E+01
1.00E+01
0.00E+00
-1.00E+01
-2.00E+01
-3.00E+01
1
3
5
Distance - ft

FIG. 13

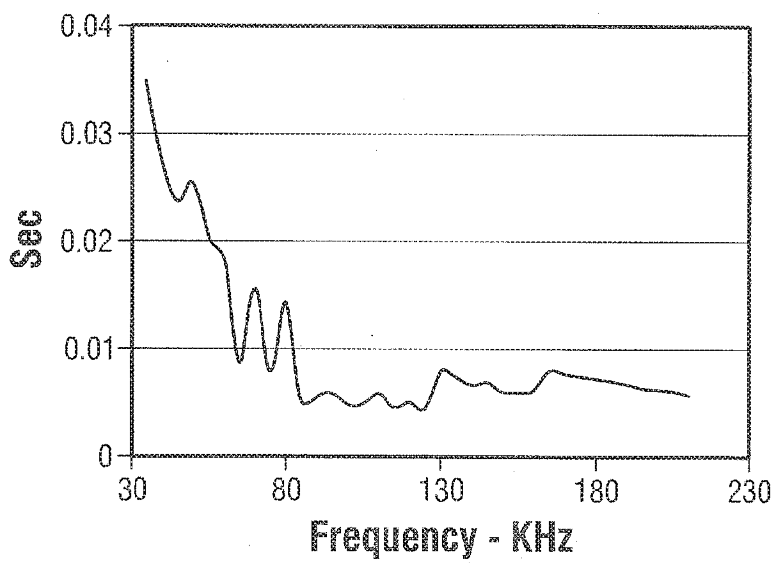

Sec
0.04
0.03
0.02
0.01
0
30
80
130
180
230
Frequency - KHz

FIG. 14

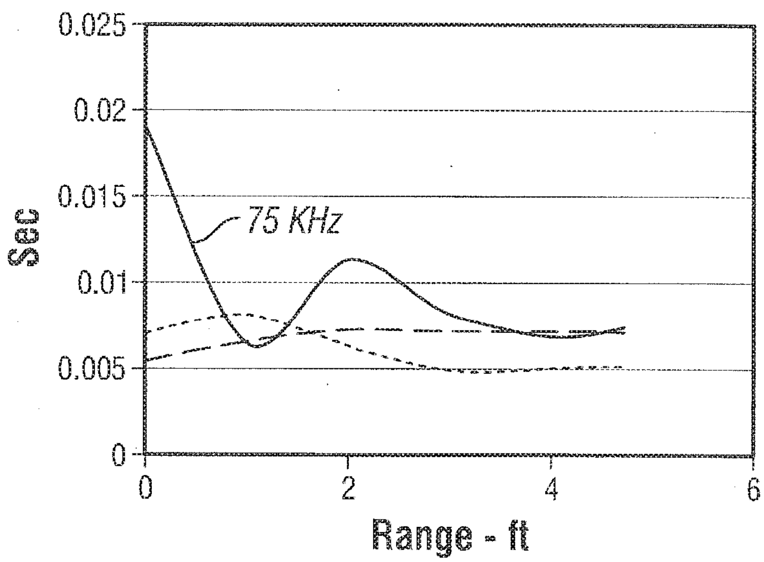


FIG. 15

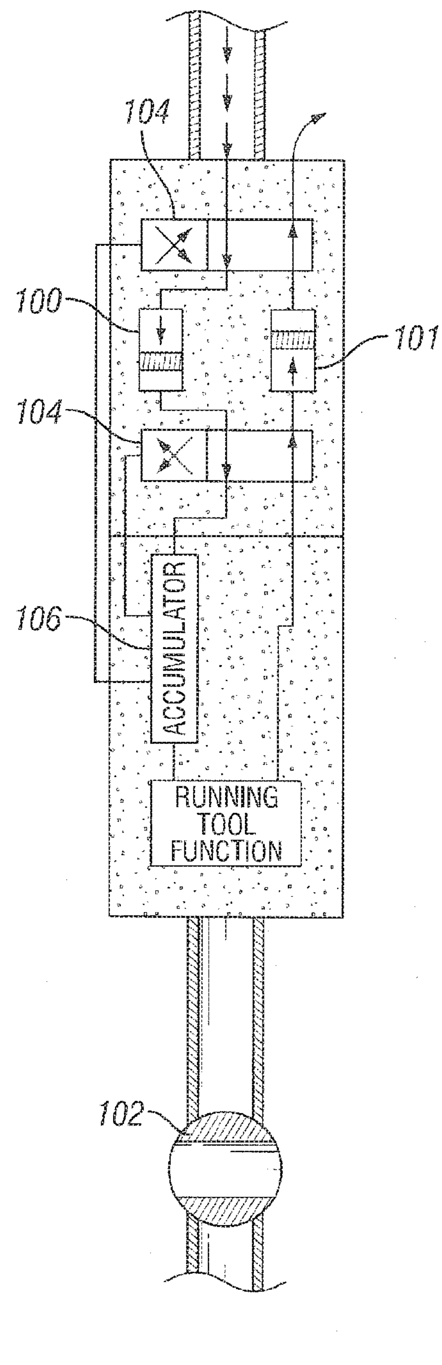


FIG. 16A

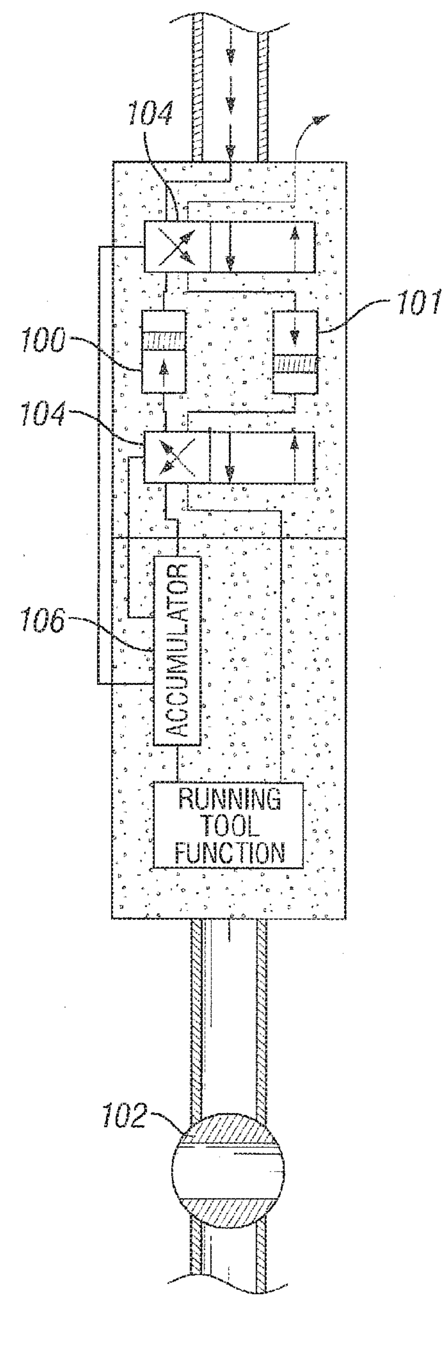


FIG. 16B

SYSTEM AND METHOD FOR MONITORING TOOL ORIENTATION IN A WELL

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application is a continuation in part of U.S. patent application Ser. No. 14/698,516, which was filed on Apr. 28, 2015, the full disclosure of which is hereby incorporated herein by reference in its entirety. This application also claims priority to and the benefit of U.S. Provisional Patent Application Ser. No. 62/149,922, which was filed Apr. 20, 2015, the full disclosure of which is hereby incorporated herein by reference in its entirety.

BACKGROUND OF THE INVENTION

[0002] 1. Field of Invention

[0003] The present disclosure relates in general to oil and gas drilling equipment, and more particularly to a system and method for monitoring the position and orientation of equipment in a wellhead assembly.

[0004] 2. Description of Related Art

[0005] Subsea running tools are typically used to operate equipment within subsea wellheads and subsea production trees. This may include landing and setting of hangers, trees, wear bushings, logging tools, etc. Current running tools are generally hydraulically or mechanically operated, and are often used to assemble a subsea wellhead by landing and setting a casing hanger and associated casing string. A mechanical running tool usually lands and sets the casing hanger within the wellhead by landing on a shoulder and undergoing a series of rotations using the weight of the casing string to engage dogs or seals of the casing hanger with the wellhead. Typical hydraulic running tools land and set the casing hanger by landing the hanger on a shoulder in the wellhead. Drop balls or darts are sometimes used to block off portions of the tool, wherein hydraulic pressure will build up behind the ball or dart causing a function of the tool to operate to engage locking dogs of the hanger or set a seal between the hanger and wellhead. Pressure behind the ball or dart is increased to release the ball or dart for use in subsequent operations. Some tools are a combination of mechanical and hydraulic tools and perform operations using both mechanical functions and hydraulically powered functions. These tools are complex and require complex and expensive mechanisms to operate, and thus are prone to malfunction due to errors in both design and manufacturing. As a result, the tools installation operations may fail at rates higher than desired when used to drill, complete, or produce a subsea well. Failure of the tool installation operation means the tool and installed equipment, e.g., a casing hanger, must be pulled from and rerun into a well, adding several days and millions of dollars to a job.

[0006] These tools provide limited feedback to operators located on the rig. For example, limited feedback directed to the torque applied, the tension of the landing string, and the displacement of the tool based on sensors on the surface equipment may be communicated to the rig operator. When a malfunction occurs downhole, however, it is not known until the string is retrieved and the tool is inspected, taking several hours and costing thousands of dollars. Also, even if there is no malfunction, rig operators generally do not have definitive confirmation that the running tool has operated as intended at the subsea location until the running tool is retrieved and inspected. A pressure test can often be passed even if the equipment has not been installed per the specification.

SUMMARY OF THE INVENTION

[0007] An example embodiment of the present invention provides a system for monitoring the orientation and position of components in an oil well. The system includes a first well component, a second well component, and a transducer attached to the first well component, for generating a pulse. The system further includes a transceiver attached to the second well component for measuring the parameters of the pulse generated by the transducer, a processor in communication with the transceiver that receives information about the parameters of the pulse as measured by the transceiver, and that calculates the position of the transceiver relative to the transducer.

[0008] An alternate embodiment of the present invention provides a system for monitoring the orientation and position of components in an oil well. The system includes a well head member attached to the top of the well, a well head sensor attached to the well head member, a hanger for insertion into the well head member, and a hanger sensor attached to the hanger, the well head sensor and the hanger sensor emitting a signal when positioned a predetermined distance from one another to indicate that the hanger is properly positioned within the well head member. The system further provides a receiver for receiving the signal from, and in communication with, the hanger sensor, the well head sensor, or both the hanger sensor and the well head sensor.

[0009] Yet another embodiment of the present invention provides a method of determining the location of a moveable component of a well head assembly having a transceiver attached thereto relative to a stationary component of the well head assembly having a transducer attached thereto. The method includes moving the moveable component of the well head assembly relative to the stationary component of the well head assembly, and emitting a pulse from the transducer. The method also includes receiving the pulse by the transceiver, determining the position of the transceiver relative to the transducer based on the time of flight of the pulse between the transducer and the transceiver, or the strength of the pulse when received by the transceiver, and determining the position of the moveable component of the well head assembly relative to the stationary component of the wellhead assembly based on the position of the transceiver relative to the transducer.

[0010] Another embodiment of the present technology includes a system for monitoring equipment in an oil well, the system including a first sensor attached to a first well component, a second sensor attached to a second well component, a transducer attached to one of the first or the second sensors, for generating a pulse, a transceiver for measuring parameters of the pulse generated by the transducer, and a processor in communication with the transceiver that receives information about parameters of the pulse as measured by the transceiver.

BRIEF DESCRIPTION OF DRAWINGS

[0011] Some of the features and benefits of the present invention having been stated, others will become apparent as the description proceeds when taken in conjunction with the accompanying drawings, in which:

[0012] FIG. **1** is a side cross-partial sectional view of a system for monitoring tool orientation in a well, according to an embodiment of the present invention.

[0013] FIG. **2** is an axial cross-sectional view of a system for monitoring tool orientation in a well, according to an alternate embodiment of the present invention.

[0014] FIG. **3** is a side cross-sectional view of the system for monitoring tool orientation of FIG. **2**;

[0015] FIG. **4** depicts a pictorial schematic representation of an experimental setup according to an embodiment of the present technology;

[0016] FIG. **5** is a transmitter as used in experiments related to the present technology;

[0017] FIG. **6** is a receiver as used in experiments related to the present technology;

[0018] FIG. **7** illustrates the spectral content of the modulated signal and the autocorrelation, based on experimental data collected related to the present technology;

[0019] FIG. **8** used the similar data to FIG. **7**, but shows the signal attenuation at various frequencies;

[0020] FIG. **9** is a scatter plot of all signal levels received at 0 degree orientation after compensating for the effects of frequency dependent attenuation;

[0021] FIG. **10** shows the correlation between RMS delay spread and frequency;

[0022] FIG. **11** shows the multipath vs. range of the experimental data;

[0023] FIG. **12** shows the relationship between loss and frequency for drilling mud;

[0024] FIG. **13** shows the relationship between gain (or loss) and distance;

[0025] FIG. **14** plots the RMS delay spread vs Frequency for Drilling mud;

[0026] FIG. **15** plots the RMS delay spread vs frequency for Drilling mud at various frequencies;

[0027] FIGS. **16**A and **16**B show a module capable of using drill string fluid pressure to create hydraulic fluid functions, according to an embodiment of the present technology.

[0028] While the invention will be described in connection with the preferred embodiments, it will be understood that it is not intended to limit the invention to that embodiment. On the contrary, it is intended to cover all alternatives, modifications, and equivalents, as may be included within the spirit and scope of the invention as defined by the appended claims.

DETAILED DESCRIPTION OF INVENTION

[0029] The method and system of the present disclosure will now be described more fully hereinafter with reference to the accompanying drawings in which embodiments are shown. The method and system of the present disclosure may be in many different forms and should not be construed as limited to the illustrated embodiments set forth herein; rather, these embodiments are provided so that this disclosure will be thorough and complete, and will fully convey its scope to those skilled in the art. Like numbers refer to like elements throughout. In an embodiment, usage of the term "about" includes +/−5% of the cited magnitude. In an embodiment, usage of the term "substantially" includes +/−5% of the cited magnitude.

[0030] It is to be further understood that the scope of the present disclosure is not limited to the exact details of construction, operation, exact materials, or embodiments shown and described, as modifications and equivalents will be apparent to one skilled in the art. In the drawings and specification, there have been disclosed illustrative embodiments and, although specific terms are employed, they are used in a generic and descriptive sense only and not for the purpose of limitation.

[0031] Throughout this disclosure, various acronyms are used. To the extent the meaning of the acronyms are not described below, the following meanings attach:

[0032] HP: high pressure

[0033] LP: low pressure

[0034] CHRT: casing hanger running tool

[0035] DPRT: drill pipe running tool

[0036] PADPRT: pressure assist drill pipe running tool

[0037] DP: drill pipe

[0038] ISOT: isolation test tool

[0039] THRT: tubing hanger running tool

[0040] SRT: seal retrieval tool

[0041] POOH: pull out of hole

[0042] DT: downhole technology

[0043] IWOCS: Intervention work over control systems

[0044] RWOCS: Remote work over control systems

[0045] HPU: Hydraulic power unit

[0046] ROV: Remotely operated vehicle

[0047] C&K: choke & kill

[0048] DCV: downhole control valve

[0049] WITS: well intervention & test system

[0050] URT: universal running tool

[0051] AUV: autonomous underwater vehicle

[0052] CART: cam actuated running tool

[0053] NSP: nominal seat protector

[0054] BML: below mudline

[0055] FIG. **1** shows a side cross-sectional view of a wellhead assembly **10** according to one embodiment of the present invention, being assembled on a surface **12**, where the surface can be the seafloor. The wellhead assembly **10** is illustrated over a well **14** that intersects formation **15** below the surface **12**. In the example, a running tool assembly **16** is employed for landing a tubing hanger **18** in the wellhead assembly **10**. The tubing hanger **18** may typically be attached to a string of tubing lowered into the well. The tubing hanger **18** can be landed in the high pressure wellhead housing, as discussed below, or can alternately be landed in, e.g., a tubing hanger spool or a horizontal tree (not shown). As shown in FIG. **1**, the tubing hanger **18** is not fully set in the wellhead assembly **10**. The running tool assembly **16** is coupled to the tubing hanger **18** by dogs **19** schematically illustrated projecting radially outward from a running tool **20** (which is part of the running tool assembly **16**) and into an inner surface of the annular tubing hanger **18**. The running tool typically lands the tubing hanger **18** or other hangers, and sets the annular seal (discussed in greater detail below). Also part of the running tool assembly **16** is a tubular string **22**, which couples to the running tool **20** and is used for deploying, operating, and orienting the running tool **20** in the wellhead assembly **10**. Further included in the running tool assembly **16** of FIG. **1** is a module **24** shown mounted onto the string **22** and above running tool **20**. Module **24** is an annular structure that can surround the drill string **22**, and can be attached to the running tool **20** via cables or other means. In some embodiments, the module **24** can be integral to the running tool **20**.

[0056] The wellhead assembly **10** includes an annular low pressure wellhead housing **25** having a conductor pipe **26** that projects into the formation **15**. An annular high pressure wellhead housing **28** surrounds the low pressure wellhead housing **25**. A blowout preventer (BOP) **27** is mounted to the high pressure wellhead housing **28**, wherein clamps (not shown) may be used for mounting the BOP **27** onto the low pressure wellhead housing **25**. Casing hangers **30**, **31** are shown landed at axially spaced apart locations within the high pressure wellhead housing **28**. Each casing hanger **30**, **31** connects to a separate string of casing extending into and cemented in the well. A riser (not shown) extends upward from the BOP **27** to a floating platform.

[0057] In some embodiments, hanger sensors **32**, **34**, **36**, **38**, **40**, and **42** are positioned on the hangers **18**, **30**, and **31**. Specifically, hanger sensors **32**, **42** may be positioned on tubing hanger **18**; hanger sensors **34**, **40** may be positioned on casing hanger **31**; and hanger sensors **36**, **38** may be positioned on casing hanger **30**. Corresponding well head sensors **44**, **46**, **48**, **50**, **52**, and **54** are positioned on the high pressure well head housing **28**. The hanger and well head sensors are situated so that when casing hanger **30** is fully seated (i.e., the seal has been lowered relative to the hanger by the running tool and energized) in the high pressure wellhead housing **28**, hanger sensors **36**, **38** are adjacent well head sensors **48**, **50**. Similarly, when casing hanger **31** is fully seated in the high pressure wellhead housing **28**, hanger sensors **34**, **40** are adjacent wellhead sensors **46**, **52**, and when tubing hanger **18** is fully seated in the high pressure housing **28**, hanger sensors **32**, **42** are adjacent well head sensors **44**, **54**. In some embodiments, the sensors may be battery powered.

[0058] Still referring to FIG. **1**, there is depicted a receiver **56** for receiving signals from the hanger and well head sensors. The receiver **56** can be located, for example, on the module **24**, although it could alternately be disposed on any equipment or module in the stack. If needed, signal repeaters can be added to the system to retransmit signals from the sensors to the receiver **56**, thereby assisting in the transmission of the signals between the sensors and the receiver **56**. For example, in the embodiment of FIG. **1**, there is shown a module stem repeater **58**, a tool stem repeater **60**, and a tool body repeater **62**. In addition, there are shown micro repeaters **64**, **66**, and **68** on the wellhead. The signals can be transmitted from the sensors to the receiver **56** in any appropriate way, such as, for example, via wires from the repeater at the running tool **20** to the receiver **56**, or wirelessly. In embodiments where the sensors communicate with the receiver **56** wirelessly, the communication may be conducted via acoustic waves or pulses.

[0059] In practice, as the well head assembly **10** is assembled, the low pressure wellhead housing **25** and high pressure well head housing **28** are secured in position over the well **14** using known methods. Thereafter, the running tool **20** is used to insert the hangers **31**, **30**, **18** into the high pressure wellhead housing **28**. An annular seal **69** may typically be included between portions of the hangers **31**, **30**, **18** and the high pressure well head housing **28**. The annular seal **69** can typically be run with the corresponding hanger and the running tool **20**, but in an upper position to enable cement returns to flow upward past the hanger. Thereafter, the running tool **20** lowers and energizes the seal **69**. Each hanger can have raised ridges, or wickers **70** on an outer surface thereof. One purpose of the wickers **70** is to engage the annular seal to help create a seal between the hanger **31**, **30**, **18** and the high pressure well head housing **28**. In order to create a proper seal, however, it is necessary that the hangers **31**, **30**, **18** be axially aligned in the appropriate position relative to the high pressure well head housing **28**. This axial alignment is one function of the hanger and well head sensors. Normally, rotational orientation or alignment is not needed for casing hangers or concentric type tubing hangers.

[0060] For example, as casing hanger **31** arrives at its designated position in the high pressure well head housing **28**, the hanger sensors **36**, **38** align with the corresponding well head sensors **48**, **50**. For hangers where rotational orientation is not carried out, the sensors **36**, **38** can be spaced around the circumference of the hanger. As the sensors align, they transmit a signal (e.g., an electromagnetic, acoustic, RFID, or other appropriate type of signal) indicating that appropriate alignment has been achieved. The signal is then received by the receiver **56**, and the operator is alerted that the casing hanger **31** is in the proper position. The range of the hanger sensors **36**, **38** and well head sensors **48**, **50** can be calibrated to any desired sensitivity. For example, in some applications, where it may be desired that the wicker interface length with the annular seal be a predetermined minimum length (e.g., 1 inch), the hanger sensors **36**, **38** and well head sensors **48**, **50** can be positioned and calibrated so that the signal (indicating that the hanger is fully set) is not transmitted by the sensors until the desired wicker interface length is achieved. The same process applies to the setting of hangers **18** and **30**.

[0061] In alternative embodiments, any number of sensors may be used on the hanger and the well head housing according to the needs of a particular assembly. In addition, the sensors may be configured in any way along the length of the hanger and the well head housing, or around the circumference thereof. The particular configuration of FIG. **1** is shown by way of example only. In addition, the sensors can be any type of sensor, including, for example, radio frequency identification (RFID) sensors or proximity sensors, such as Hall effect magnetic sensors.

[0062] Further shown in FIG. **1** is a controller **67** that communicates with the receiver **56** via a communication means **68**. The controller can be located subsea near the wellhead, and can communicate with an operator on the surface in any appropriate way, such as, for example, via an umbilical, wirelessly, such as by acoustic pulse, by displaying information for collection by a remotely operated vehicle, etc. In one embodiment, an output of controller **67** is available to personnel operating the running tool assembly **16**, and communication means **68** can be wireless, conductive elements, fiber optics, acoustic, or combinations thereof. In an example of landing tubing hanger **18** within wellhead assembly **10**, communication between hanger sensors **32**, **42** and well head sensors **44**, **54** is monitored at controller **67**, and transmitted from receiver **56** to controller **67** by communication means **68**. The position of the tubing hanger **18** can be estimated based on signals received from the sensors **32**, **42**, **44**, **54**. If no signal is received by receiver **56**, this may indicate that tubing hanger **18** is at an incorrect position. Thereafter, the tubing hanger **18** can be repositioned until appropriate signals are received. Although the above description principally describes the sensors as measuring the axial position of the hangers relative to the well head housing **28**, other parameters can also be measured, such as azimuthal position, and inclination of the hangers.

[0063] Repositioning of the hangers **18**, **30**, **31** can be performed before cementing by manipulating the running tool assembly **16**. Moreover, the step of repositioning can be done based on signals received by the receiver **56**, and transmitted to the controller **67**. In addition, repositioning can be done iteratively until a signal is received indicating that the casing hanger **30**, **31** is positioned as desired.

[0064] The embodiment of the present invention shown in FIG. **1** is advantageous over known systems because it helps to ensure that the seal between the hangers and well head housing is sound, and to prevent seal leakage. It accomplishes this by helping to ensure that the components are appropriately aligned when the seal is energized.

[0065] Referring now to FIGS. **2** and **3**, there is depicted an alternate embodiment of the present invention, including a transducer **72** (e.g., and acoustic transmitter) installed in a port **74** that extends through a sidewall of the BOP **27**, and a plurality of transceivers **76** formed in a transceiver array. The transceivers **76** can be attached to the running tool **20** in any appropriate configuration. The transducer **72** can send a pulse P, such as an electromagnetic or acoustic pulse, generally inwardly toward the axis A of the running tool **20**, which pulse P expands as it moves away from the transducer **72**. As the pulse P travels away from the transducer **72**, it is received by the transceivers **76**, which in turn measure parameters of the pulse, such as the time of flight of the pulse P between the transducer **72** and each transceiver **76**, and/or the strength of the pulse P. The transceivers **76** can be battery powered. Alternatively, the transceivers **76** can be of a type that do not require power, such as SAW chips, that instead reflect the pulse P back to the transducer **72**.

[0066] As particularly shown in FIG. **2**, as the pulse P travels, it expands parallel to a plane defined by the X and Y axes. Based upon the strength, direction, and/or time of flight of the pulse P at or to a particular transceiver **76**, the position of the transceiver **76** relative to the transducer **72** along the X-Y plane can be determined. Simultaneously, as particularly shown in FIG. **3**, the pulse P expands upward and downward relative to a datum plane D, which is positioned at a height in the BOP even with the transducer **72**, and which is substantially perpendicular to the axis A of the running tool **20**. Based upon the strength, direction, and/or time of flight of the pulse P at a particular transceiver **76**, the height H of the transceiver **76** relative to the transducer **72** can be determined as well.

[0067] Once the above data about the strength, direction, and/or time of flight of the pulse P is collected by the transceivers **76**, the information can be sent to a controller or processor **80**, which uses known triangulation techniques to determine the position of each transceiver **76** relative to the transducer **72**. The processor **80** can be located subsea near the wellhead, and can communicate with an operator on the surface in any appropriate way, such as, for example, via an umbilical, wirelessly, such as by acoustic pulse, by displaying information for collection by a remotely operated vehicle, etc. Transmission of the data can be achieved by any appropriate transmission means **82**, including, for example, wires (not shown) or wireless transmission via radio waves or other means. Thus, using known triangulation techniques, the generation of pulses P from the transducer **72** and subsequent measurement of the strength, direction, and/or time of flight of those pulses P by the transceivers can generate the necessary data to determine the position and orientation of the running tool **20** relative to the BOP **27**. The processor can also convey information to the operator about the position of the running tool **20**. This can be accomplished, for example, by providing the information on a display screen (not shown).

[0068] Although the transducer **72** is shown in FIGS. **2** and **3** to be attached to the BOP **27**, in practice the transducer **72** could be attached to any part of the system, such as, for example, a drilling connector, well head housing, or tree body. Similarly, the transceivers could be attached to any equipment lowered into a well, such as, for example, a drill string, or a hanger. In addition, the position of the transducer **72** and transceivers **76** could be reversed, so that the transducer **72** is attached to the running tool **20** or other equipment lowered into the well, and the transceivers **76** are attached to stationary parts of the system, such as the BOP or the well head housing.

[0069] The embodiment of the present invention shown in FIGS. **2** and **3** provides certain advantages over other known systems. For example, the ability to accurately determine the position of the running tool **20** or other equipment reduces the number of trips needed to place components in the well. Using the transducers and transceivers described herein, downhole equipment can more easily be located and installed in a single trip as the operator gets real time feedback. Furthermore, installation of the downhole equipment is more accurate, which leads to long term reliability of the equipment.

[0070] In addition to the above, alternate embodiments of the present technology include embodiments where an acoustic receiver is located on a choke and kill port in a BOP stack, for example. Alternatively, the acoustic receiver may be located in a subsea production tree, on an ROV, or elsewhere. The data received may then be transmitted back to the surface, or any other remote location, with the ability to view this data in real time and act accordingly. The data transmission can occur on an existing communication path such as an umbilical. It is also possible to communicate back to the running tool in the reverse direction to send instructions to the tool to perform additional functions and interact with the tool as necessary. The module can perform specified functions, such as counting drill string rotations at the running tool rather than on the surface.

[0071] This technology also allows many different functions that currently occur in a running tool to be recorded and transmitted. For example, various different types of sensors can be attached to the running tool. These sensors may include, but are not limited to, temperature and pressure transducers, proximity sensors, and linear variable displacement transducers. Sensors can also be located within the communication module itself, and may include temperature and pressure transducers, rotation sensors, hydrophones, accelerometers, gyroscopes, proximity sensors, imaging sensors, and strain gauges, among others. The data obtained by each of these sensors can then be transferred into the module for data processing and storage. This transfer may be via hard wire or wirelessly. Within this module can be at least one acoustic transmitter, battery, and supporting electronic hardware for processing and data storage along with the previously mentioned sensors.

[0072] In some embodiments, after data processing, the data can be sent via acoustic transmitters from the module through the seawater or drilling mud to the acoustic receiver located in a choke and kill port of a BOP, subsea production tree, an ROV in open water, or otherwise. This real time data can be sent to the required location for status indication of the running tool function, and allow the user to react accordingly. Should additional actions need to be taken to alter the tool, or perform an additional task, a signal may be sent from the surface back to the running tool. This signal can activate a function either electrically, hydraulically, or a combination of both.

[0073] One technical advantage for this equipment is the positive verification of subsea operations within a running tool. This positive verification can be transmitted in real time. Also, a database of stored information allows analysis for future design considerations and metrics tied to the operation and performance of these tools.

[0074] Certain example embodiments of the technology include use of sensors on a running tool, and/or also on other components of a drilling or production system, such a components permanently installed in a well. Potential uses for the present technology can include, for example:

- [0075] Jetting Conductor Casings with HP/LP Housings, including sensors to measure inclination, depth, proximity, stick up height, etc;
- [0076] Running Casing (CHRT, DPRT, PADPRT), including sensors to measure seal setting stroke, pressure, temperature, debris detection, dp rotations, landing verification, tension/compression/bending, etc.
- [0077] Landing an SS Production Tree, including sensors to measure depth and proximity;
- [0078] BOP Test (ISOT, Plug Tool), including sensors to measure pressure, hydrophones, imaging, etc.;
- [0079] Running Tubing/Completion/Production (THRT, URT), including sensors to measure depth, proximity, orientation, landing verification, etc.;
- [0080] Seal Retrieval (SRT), including sensors for confirming setting of seal on SRT prior to POOH, stroke, tension, etc.;
- [0081] Wear Bushing (Bit Run Tool, Spear Tool), including sensors to confirm land/pull;
- [0082] Clean & Flush Tool, including sensors for measuring fluid pressure, velocity, debris indication, inspection, etc.;
- [0083] Drilling, including pipe joint detection and kick detection;
- [0084] Valves, including sensors for measuring actuator/Gate position, leak detection, and erosion detection;
- [0085] DT, surface, and Riser Inspection;
- [0086] Stand alone, plug & play, for example, for use with tree equipment due to large variation in operations;
- [0087] Tree position lock indicator (vs. ROV visual monitoring);
- [0088] No position indicator on valves;
- [0089] Imbedded Sensors;
- [0090] IWOCS, RWOCS;
- [0091] HPU on ROV;
- [0092] ROV at, for example, 8000 ft in 1 hr (i.e., fast deployment, vs. riser run or drill pipe run);
- [0093] Remove need for ROV/umbilical by using work class vessel;
- [0094] Debris on tubing hanger is an issue;
- [0095] THRT power through C&K port patented by Vetco;
- [0096] Electric running tools;
- [0097] Electric power & operations;
- [0098] EXPRO (test trees);
- [0099] 4" dia×40' accumulators inside riser joint, DCV;
- [0100] WITS (no control system, direct), 2 umbilicals required;
- [0101] Use module as control system f/test tree;
- [0102] Simplify way test trees are used;
- [0103] MMS allows for 1 barrier for a few days downhole while BOP removed from tree;
- [0104] URT+Tree Cap function possible use of module;
- [0105] ROVS not common on jackup rigs;
- [0106] Bluefin Robotics (AUVs);
- [0107] Jumper Metrology (distance measurement between trees and manifolds);
- [0108] Gyrocompass on ROV for tree positioning (rotation), including heading indication on tree;
- [0109] In-Riser opportunities;
- [0110] Crown plug running tools—wireline;
- [0111] Train tools push/pull (autonomous);
- [0112] Tree wear bushing problems inside tubing spool, including wireless, autonomous BOP upper body;
- [0113] Drill pipe centralizing (annular on BOP stack);
- [0114] CWOR & Riser load monitoring;
- [0115] Valves, including actuation force/pressure monitoring, hydrophones for leakage rates, and wear detection;
- [0116] Auto tree landing, including self-aligning;
- [0117] Riser inspection, ultrasonic imaging, production risers;
- [0118] B Annulus monitoring;
- [0119] A drill ahead tool for jetting, including measuring inclination

[0120] As briefly mentioned above, additional features of the present technology may include the ability to communicate to an ROV in open water, such as via a low frequency transmitter. Such an open water application may allow for more flexibility to the hardware that can be used. ROV communication may use acoustics to transmit from the module directly downward to the seafloor for accurate height positioning. In addition, pressure/temperature transducers can be added to a low pressure (LP) housing.

[0121] The present technology can also have the ability to control equipment and provide feedback or positive confirmation. Such control and feedback can be related to such uses as converting drilling fluid (dirty) to a clean fluid (via bellows/pistons), or to supply hydraulic power & controls electro-hydraulically. In addition, the technology can be used to provide communications, or a data hub, with permanently installed sensors. For example, in wellhead fatigue monitoring, a module as described herein can be used to permanently monitor installed equipment, such as the structural integrity of a subsea well. In this example, a module according to embodiment 2 of the succeeding paragraph (i.e. an open water, permanent module) can be permanently deployed with the wellhead, which can perform the duties of monitoring and recording stress/strain data from the sensors. This data can be retrieved by some other system intermittently or continuously. Examples of devices that can communicate with this module include a tree, a BOP, ROV, AUV, or down-line from a surface vessel. Other technologies that can benefit from the power and control provided by a module as described herein include sensors for measuring and communicating temperature, pressure, environmental conditions, cement quality, micro-seismic conditions, corrosion detection, etc.

[0122] Example embodiments of the present technology can include at least the following six embodiments, or classes, including modules and sensors that work in 1) open water and are retrievable, 2) open water and are permanent, 3) in-riser on a drill string, 4) in-riser drill ahead annular, 5) sub-mudline, and 6) on tubing/wireline. The following chart shows a summary of the different classes and possible applications for each (and key indicating meaning of acronyms, etc.):

	Class I (Open Water, Retrievable)	Class II (Open Water, Permanent)	Class III (In-Riser on Drill String)	Class IV (In-Riser Annular)	Class V (Below Mudline)	Class VI (On Tubing/Wireline)
Embodiment I (RM&D, Record)	CART/DAT, Prod. Base Run/Retr., Tree RT	Tree Connector, Wellhead, BOP	PADPRT, URT, ISOT, SRT, Riser Inspection, C&F	Wear Bushing, NSP, Riser Inspection	SMART, BML (16", 18")	Crown Plug Running, Fishing Bot, Prod. Riser Inspection
Embodiment II (Gen I + 2 Way Comm)	CART/DAT, Prod. Base Run/Retr., Tree RT	Tree Connector, Wellhead, BOP	PADPRT, URT, ISOT, SRT, Riser Inspection, C&F	Wear Bushing, NSP, Riser Inspection	SMART, BML (16", 18")	Crown Plug Running, Fishing Bot, Prod. Riser Inspection
Embodiment III (Gen II + Controls)	CART/DAT, Prod. Base Run/Retr., Tree RT	Tree Connector, Wellhead, BOP	PADPRT, ISOT, SRT	Wear Bushing, NSP	SMART BML (16", 18")	Crown Plug Running, Fishing Bot
Embodiment IV (Autonomous)	Debris/Tree/Corrosion Caps		ISOT, Plug Tool			Crown Plug Running, Fishing Bot

CART/DAT Cam actuated/drill ahead tool to run/land high pressure & low pressure housings
PADPRT Lands casing hanger, rotates drill pipe to allow seal setting, strokes down sets seal, activates bulk rubber to test seal
URT Lands tubing hanger in wellhead/tree, performs hydraulic funtions and injection as required
ISOT Energizes bulk rubber in wellhead to allow pressure testing of BOP stack
SRT Seal retrieval tool
C&F Clean & flush tool washes out debris from seal location prior to setting seal
Wear Bushing/NSP Annular equipment designed to protect bore of housing during drilling
BML Below Mudline equipment, usually 16 & 18" landed below high pressure housing in conductor
Fishing Bot Autonomous vehicle capable of preparing a broken/damaged drill string for retrieval in a "fishing" operation

[0123] In addition, some embodiments may be autonomous, in-riser, drop in embodiments. With regard to autonomous modules, these modules can be autonomous in control function primarily. Certain autonomous modules, however, can also provide the power to perform functions entirely remotely. For example, certain vehicles equipped with autonomous modules can be self-propelled once they are deployed with the tubing. Such vehicles would not need a wireline, E-line, or tugger line for power or control, as is typical for this type of installation. Such a vehicle can use buoyancy or hydro-propulsion to lower itself, and the equipment it is installing/removing, into position. Many 'cased hole' or 'open hole' logging/inspection type tools can benefit from this technology. In addition, the technology described herein and identified in the above-named embodiments, can be used for set/pull function, to supply electro-hydraulic modes, to find tree stackup, and to control functions in a hydraulic power unit (using drill pipe hydraulic pressure). The technology can be semi-autonomous or autonomous.

[0124] The technology can be further divided into additional embodiments and class designations. For example, further embodiments of the technology can include 1) data recording only, 2) data recording plus data communication, and 3) autonomous. In addition, various classes can be determined by the function of the running tool that the module will be attached to. For example, some tools are run in an open water environment such as cam actuated running tools (CART) for installing a low or high pressure housing. An alternate to an open water tool could be an in-riser tool such as a PADPRT, etc. Such a tool is typically run on the drill string. An alternate to that would be a drill ahead tool (DAT) in which the module would typically stay with the running tool body as the drill ahead operation is performed. This would not allow the module to be threaded to the drill string and would likely be configured in an annular envelope. Below mudline operation may require significantly different communication methods due to the distance from the BOP. In-riser autonomous tools would allow specific operations to be performed without being coupled to a drill string.

Experimental Data and Results

[0125] Experimental tests have been conducted on the present technology. Described herein in this section is the collection of data for the characterization of an acoustic transmission channel within a Blowout Preventer used in subsea wells. Data was collected over a wide range of frequencies from 35 KHz to 220 KHz. This section also describes the processing of that data to characterize the multipath interference and propagation losses.

[0126] The process of developing a well for subsea energy production may involve the installation of several layers of steel casings which protect the well from collapse due to high pressures. The setting and sealing of these casings occurs at the well head, which can be as much as 10,000 ft below the ocean surface. Well drilling operators have no visibility at the point where the seal must be made and typically rely on pressure testing after the sealing operation has been completed. It is costly to go back and attempt to reset the seal if the pressure test fails and the seal was not properly set. Having sensors which can detect critical parameters in the seal setting process increases the probability that a proper seal has been made, but also raises the issue of how to communicate the sensor information back to the operator. The Blowout preventer which sits at the well head has a communications conduit to the well operator. An additional line can be added to the umbilical to support sensor related communications to the surface. That leaves the last hop of communications between the tool which sets the well casing and would house the sensors to the blowout preventer. In this section is explored the ability of both drilling mud and water (either of which can be present) to support digital communications using acoustic methods.

[0127] Referring to FIG. 4, there is shown a pictorial schematic representation of the experimental setup. A Blow Out Preventer (BOP) is used as the fluid vessel, transmitting transducers are mounted to the base of a drill string pipe, and a receiving transducer is mounted in one of the choke kill ports near the top of the BOP. The experiment was conducted with both fresh water and drilling mud as an acoustic media.

[0128] In the experiment, transducers covering various frequency ranges (Low: 40 Khz-75 Khz, Medium: 80 Khz-130 KHz, High: 130 KHz-210 KHz) were mounted on a disk at the base of the drilling pipe for transmission, as well as in the choke-kill port on the side of the BOP (these were swapped out during each phase of the experiment). The actual ram mechanisms were not installed in the BOP, which left large cavities.

[0129] There is shown in FIG. 5 the transmitter used in the experiments. The transmitter consisted of a differential power amplifier consisting of two LT1210s which was capable of driving +/−23V p-p. and up to 1.1 amperes (A) of current. Transducer loads were not characterized but assumed to be about 100 ohms.

[0130] The receiver shown in FIG. 6 consisted of a low noise differential amplifier, anti-aliasing filter, and analog to 16 bit digital to analog converter (Omega OMB-DAQ-3005) capable of storing 1 million samples, and sampling at 1 million samples per second. A computer was used to store off each data file for post processing. An FPGA was programmed to produce a cycling 1023 bit code sequence that was derived from a 10th order primitive polynomial that produced a pseudo random sequence with excellent autocorrelation characteristics and flat spectral response. Code sequence generation was synchronized to the carrier frequency which was injected using a signal generator. An arbitrary choice was made to sequence the code every three cycles of the carrier. This digital sequence was then fed into a modulator. Binary phase shift keying (BPSK) was used as the modulation technique. This was accomplished by using a multiplexer which choose the carrier or the inverse of the carrier based on a 1 or 0 from the FPGA.

[0131] Post processing was done in Matlab. The total signal power received was calculated and used for attenuation measurements. A sliding window correlation was performed to generate a power delay profile and the RMS delay spread was calculated from the Power Delay Profile. As a test of the goodness of the data pattern used, an ideal pattern was generated in Matlab and evaluated. FIG. 7 illustrates the spectral content of the modulated signal and the autocorrelation.

[0132] With respect to the experimental procedure, data was collected at seven different ranges, including: 4.7 ft, 4 ft, 3 ft, 2 ft, 1 ft, 0 ft, and −1 ft. At 4.7 ft the drill pipe and the transmitters were as close to the floor of the BOP as was possible given the height of the transducers and the bend radius requirements of the cable. At 0 ft. the transmitter face was level with the receiver and at—1ft. the transmitter was above and facing away from the receiver. The pipe was also rotated 0 degrees, 90 degrees and 180 degrees. This allowed for taking measurements when the transmitter was partially and completely shadowed by the drill pipe. Measurements were also taken while the drill pipe was rotating. Further, experimentation was conducted with placing sound absorbing foam at the air water interface. This was done to be able to determine if that interface, which would not be present in a real scenario, would affect the measurements. Raw measured data was corrected or normalized based on the transmitter output power and frequency response of all elements in the system (e.g., receiver, driver, and transducer response).

[0133] Initial Experiments were performed with the BOP filled with fresh water. FIG. 8 shows the signal attenuation at various frequencies. This data was taken at 0 degree orientation and at a distance of 4.7ft. The attenuation or absorption roughly follows a line: A(dB)=−0.1206 f(Khz)−18.96, which line is plotted to show fit.

[0134] Range is also a factor in attenuation. FIG. 9 is a scatter plot of all signal levels received at 0 degree orientation after compensating for the effects of frequency dependent attenuation. This data has quite a bit of variability and roughly follows the relationship: L9 dB)=1.2234 d(ft) +8.043. One cannot tell from the scatter plot alone, as it contains data for all frequencies, that there appears to be little to no additional frequency dependent factors in the loss due to range. At 4.7 ft., pipe rotation has no effect. The greatest effect is at 0 ft. where 90 degrees rotation has 3 dB more loss and 180 degrees rotation has 6 dB loss. The difference between the 0 foot range and −1 foot range is at most 10 dB attentional loss.

[0135] RMS delay spread is a basic measurement in the amount of multipath in a given channel. FIG. 10 shows a definite correlation between RMS delay spread and frequency. As one might expect, as the attenuation factor of the channel increases the multipath intensity decreases. Furthermore, as shown in FIG. 11, range tends to have little effect on Multipath except when the transmitter and receiver are adjacent to each other; this can be due to prolonged echoes between the drill pipe and the side wall of the BOP.

[0136] After completing the data collection in water, the BOP was filled with water based drilling mud, and the experiments were repeated. FIG. 12 shows the relationship between loss and frequency for drilling mud. Note that the slope is opposite for that of water, and that drilling mud becomes less absorptive with increased frequency. The regression equation for this relationship is: A9 dB)=0.127 f(KHz)−84.17. There is significantly more loss in drilling mud than in water but the relationship to frequency is reverse.

[0137] As shown in FIG. 13, for drilling mud there seems to be no consistent relationship between loss and distance. There was, however, more loss at the 3 ft. mark consistently. This is about at the position of the ram cavity. Beyond this point, the attenuation stayed the same, or actually became less, as with movement beyond that location. Orientation seems to have no effect when in mud except at 0 ft., where the difference between 0 degrees and 180 degrees is 45 to 50 dB. In addition, the −1 foot range shows about 10 dB greater attenuation than the 1 foot range.

[0138] FIG. 15 plots the RMS delay spread vs Frequency for Drilling mud. This plot actually follows what one would expect if drilling mud loss increased with frequency. Note that the delay spread information was collected at the 1 ft. range up to 125 KHz and then at the 4.7 ft. range up to 175 KHz. That is beyond the point where the RMS delay spread seems to stay around 8 msec.

[0139] FIG. 15 plots RMS delay spread vs range at various frequencies. There may be a small dependency at lower frequencies as is seen in FIG. 14, but for the most part there is little to no strong relationship between multipath and position at the higher frequencies.

[0140] One example of a possible use for the module of the present technology is the hydraulic fluid power transfer module shown, for example, in FIGS. **16**A and **16**B. FIGS. **16**A and **16**B show a module capable of using drill string fluid pressure to create hydraulic fluid functions. Specifically, FIG. **16**A shows the module with a first piston **100** in the down position and a second piston **101** in the up position. FIG. **16**B shows the module with the first piston **100** in the up position and the second piston **101** in the down position. This module can transfer "dirty" fluid to a clean, closed system hydraulic fluid, perform a pneumatic operation, and return to dirty fluid and dump to a low pressure environment. This module can be controlled by the present technology, or have its own dedicated controls built internally to the module. This module would require an inline ball valve **102**, or similar, to temporarily close off the downhole flow of the drill string fluid and to redirect this flow into the module for power transfer. The module can also include a solenoid 4-way valve **104** that can be controlled by known control systems, and that, in some embodiments, can be powered by an accumulator **106**.

[0141] The present invention described herein, therefore, is well adapted to carry out the objects and attain the ends and advantages mentioned, as well as others inherent therein. While a presently preferred embodiment of the invention has been given for purposes of disclosure, numerous changes exist in the details of procedures for accomplishing the desired results. Previously known devices are limited to indicating the downhole arrival of the well tool. These devices however are unable to calculate the orientation, alignment, or axial inclination of components in the wellhead assembly, which are features of embodiments herein, and which enables a more precise installation of such components. These and other similar modifications will readily suggest themselves to those skilled in the art, and are intended to be encompassed within the spirit of the present invention disclosed herein and the scope of the appended claims.

What is claimed is:

1. A system for monitoring equipment in an oil well, the system comprising:

a first sensor attached to a first well component;

a second sensor attached to a second well component;

a transducer attached to one of the first or the second sensors, for generating a pulse;

a transceiver for measuring parameters of the pulse generated by the transducer; and

a processor in communication with the transceiver that receives information about parameters of the pulse as measured by the transceiver.

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