(57) Abstract: A drill rig system for drilling a wellbore in the earth, the drill rig system comprising: a drill rig comprising: a substructure supporting a rig floor and a mast extending vertically above the rig floor; a top drive supported by a line spooled between a crown block and a travelling block, a carriage that is guided by the guide rails on the mast, wherein the carriage has at least one arm that extends/retracts to position the top drive farther/closer to the mast; a theodolite and/or laser ranging systems positioned to reflect a laser beam off a reflector associated with the top drive to determine the top drive's position relative to a well axis; and a controller of the at least one arm based on the top drive position determined by the theodolite and/or laser ranging systems.

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DYNAMIC BLOCK RETRACTION FOR DRILLING RIGS

TECHNICAL FIELD

The present disclosure relates in general to drilling rigs for drill wellbores and, more particularly, to drilling rigs with top drive drilling systems.

BACKGROUND

Top drives are used to suspend and rotate a string of drill string and/or casing in drilling applications. The top drive is movable along a mast that extends upward from a rig floor. The top drive is supported by and moved by a drilling line wrapped on a set of sheaves and connected to the drawworks at one extremity. The top drive supports the drill string via a thrust bearing. Mud may be pumped into the drill string via a swivel. Furthermore, the top drive generally includes one or more motors (electric or hydraulic) which generate(s) the rotation of the drill string. The reaction torque applied to the top drive may be transmitted to the mast via a set of rollers attached to the top drive chassis.

In some situations, the path along which the top drive moves in the mast may tend to deviate from the axis of the well. This may occur via uneven compaction of the earth below the rig floor and/or due to uneven bending of the mast, which generally has an asymmetric, U-shaped geometry. When the path of the top drive differs from the axis of the well, the drill pipe being rotated by the top drive may engage the well equipment (e.g., the blowout preventer, rotating control device, etc.), which may potentially damage the well equipment, or otherwise damage the drill pipe.

SUMMARY OF THE INVENTION

According to one aspect of the invention, there is provided a drill rig system for drilling a wellbore in the earth, the drill rig system comprising: a drill rig comprising: a substructure supporting a rig floor and a mast extending vertically above the rig floor; a top drive supported by a line spooled between a crown block and a travelling block, a carriage that is guided by the guide rails on the mast, wherein the carriage has at least one arm that extends/retracts to
position the top drive farther/closer to the mast in a preferred direction typically opposed to the
catwalk; a sensing method allowing to determine the horizontal distance from the center of the
top-drive quill and the vertical axis of the well (in the direction defined by the block-retract
system). Such sensing method can be based on theodolite and/or laser ranging systems
positioned to reflect a laser beam off a reflector associated with the top drive to determine the
top drive's position relative to a well axis; and a controller of the at least one arm based on the
top drive position determined by the theodolite and/or laser ranging systems.

A further aspect of the invention provides a drill rig system for drilling a wellbore in the earth,
the drill rig system comprising: a drill string turning device; a sensor of the position of the
turning device relative to a well axis; and a mover of the turning device to a position on the
well axis.

According to another aspect of the invention, there is provided a method for drilling a wellbore
in the earth, the method comprising: turning a drill string with a turning device; determining
the position of the turning device relative to a well axis; and positioning the turning device on
the well axis.

**BRIEF DESCRIPTION OF THE DRAWINGS**

The accompanying drawings, which are incorporated in and constitute a part of this
specification, illustrate embodiments of the present teachings and together with the description,
serve to explain the principles of the present teachings. In the figures:

Figure 1 illustrates a schematic view of a drilling rig and a control system, according to an
embodiment.

Figure 2 illustrates a schematic view of a drilling rig and a remote computing resource
environment, according to an embodiment.

Figure 3A illustrates a conceptual, side, schematic view of a drilling rig, according to an
embodiment.

Figure 3B illustrates a conceptual, side, schematic view of a drilling rig, according to an
alternate embodiment.
Figure 4A illustrates a conceptual, front, schematic view of the drilling rig with the top drive axis differing from the well axis, according to an embodiment.

Figure 4B illustrates a conceptual, front, schematic view of the drilling rig with the top drive axis differing from the well axis, according to an alternative embodiment.

Figure 5 illustrates a schematic view of a computing system, according to an embodiment.

Figure 5A illustrates some of the deformations associated with rig operation, as well as the paths potentially followed by the travelling block, in particular, the deformations affecting the travel path of the travelling block.

Figure 5B shows a schematic diagram of a drill rig and two laser generators and angle measurement devices.

Figure 5C shows a schematic diagram of a drill rig and two laser generators and devices for measuring the distances between the laser generators and the drill rig.

Figures 6A, 6B and 6C illustrate perspective, and side views, respectively, of an embodiment of block retraction system.

Figure 7 is a side view of a rig and a laser generator.

Figure 8 is a schematic illustration of a side view of a rig jack.

**DETAILED DESCRIPTION**

Reference will now be made in detail to specific embodiments illustrated in the accompanying drawings and figures. In the following detailed description, numerous specific details are set forth in order to provide a thorough understanding of the invention. However, it will be apparent to one of ordinary skill in the art that the invention may be practiced without these specific details. In other instances, well-known methods, procedures, components, circuits, and networks have not been described in detail so as not to unnecessarily obscure aspects of the embodiments.
It will also be understood that, although the terms first, second, etc. may be used herein to describe various elements, these elements should not be limited by these terms. These terms are merely used to distinguish one element from another. For example, a first object could be termed a second object, and, similarly, a second object could be termed a first object, without departing from the scope of the present disclosure.

The terminology used in the description herein is for the purpose of describing particular embodiments only and is not intended to be limiting. As used in the description of the invention and the appended claims, the singular forms "a," "an" and "the" are intended to include the plural forms as well, unless the context clearly indicates otherwise. It will also be understood that the term "and/or" as used herein refers to and encompasses any and all possible combinations of one or more of the associated listed items. It will be further understood that the terms "includes," "including," "comprises" and/or "comprising," when used in this specification, specify the presence of stated features, integers, steps, operations, elements, and/or components, but do not preclude the presence or addition of one or more other features, integers, steps, operations, elements, components, and/or groups thereof. Further, as used herein, the term "if" may be construed to mean "when" or "upon" or "in response to determining" or "in response to detecting," depending on the context.

Figure 1 illustrates a conceptual, schematic view of a control system 100 for a drilling rig 102, according to an embodiment. The control system 100 may include a rig computing resource environment 105, which may be located onsite at the drilling rig 102 and, in some embodiments, may have a coordinated control device 104. The control system 100 may also provide a supervisory control system 107. In some embodiments, the control system 100 may include a remote computing resource environment 106, which may be located offsite from the drilling rig 102.

The remote computing resource environment 106 may include computing resources locating offsite from the drilling rig 102 and accessible over a network. A "cloud" computing environment is one example of a remote computing resource. The cloud computing environment may communicate with the rig computing resource environment 105 via a network connection (e.g., a WAN or LAN connection).
Further, the drilling rig 102 may include various systems with different sensors and equipment for performing operations of the drilling rig 102, and may be monitored and controlled via the control system 100, e.g., the rig computing resource environment 105. Additionally, the rig computing resource environment 105 may provide for secured access to rig data to facilitate onsite and offsite user devices monitoring the rig, sending control processes to the rig, and the like.

Various example systems of the drilling rig 102 are depicted in Figure 1. For example, the drilling rig 102 may include a downhole system 110, a fluid system 112, and a central system 114. In some embodiments, the drilling rig 102 may include an information technology (IT) system 116. The downhole system 110 may include, for example, a bottomhole assembly (BHA), mud motors, sensors, etc. disposed along the drill string, and/or other drilling equipment configured to be deployed into the wellbore. Accordingly, the downhole system 110 may refer to tools disposed in the wellbore, e.g., as part of the drill string used to drill the well.

The fluid system 112 may include, for example, drilling mud, pumps, valves, cement, mud-loading equipment, mud-management equipment, pressure-management equipment, separators, and other fluids equipment. Accordingly, the fluid system 112 may perform fluid operations of the drilling rig 102.

The central system 114 may include a hoisting and rotating platform, top drives, rotary tables, kellys, drawworks, pumps, generators, tubular handling equipment, derricks, masts, substructures, and other suitable equipment. Accordingly, the central system 114 may perform power generation, hoisting, and rotating operations of the drilling rig 102, and serve as a support platform for drilling equipment and staging ground for rig operation, such as connection make up, etc. The IT system 116 may include software, computers, and other IT equipment for implementing IT operations of the drilling rig 102.

The control system 100, e.g., via the coordinated control device 104 of the rig computing resource environment 105, may monitor sensors from multiple systems of the drilling rig 102 and provide control commands to multiple systems of the drilling rig 102, such that sensor data from multiple systems may be used to provide control commands to the different systems of the drilling rig 102. For example, the system 100 may collect temporally and depth aligned
surface data and downhole data from the drilling rig 102 and store the collected data for access
onsite at the drilling rig 102 or offsite via the rig computing resource environment 105. Thus,
the system 100 may provide monitoring capability. Additionally, the control system 100 may
include supervisory control via the supervisory control system 107.

In some embodiments, one or more of the downhole system 110, fluid system 112, and/or
central system 114 may be manufactured and/or operated by different vendors. In such an
embodiment, certain systems may not be capable of unified control (e.g., due to different
protocols, restrictions on control permissions, etc.). An embodiment of the control system 100
that is unified, may, however, provide control over the drilling rig 102 and its related systems
(e.g., the downhole system 110, fluid system 112, and/or central system 114).

Figure 2 illustrates a conceptual, schematic view of the control system 100, according to an
embodiment. The rig computing resource environment 105 may communicate with offsite
devices and systems using a network 108 (e.g., a wide area network (WAN) such as the
internet). Further, the rig computing resource environment 105 may communicate with the
remote computing resource environment 106 via the network 108. Figure 2 also depicts the
aforementioned example systems of the drilling rig 102, such as the downhole system 110, the
fluid system 112, the central system 114, and the IT system 116. In some embodiments, one or
more onsite user devices 118 may also be included on the drilling rig 102. The onsite user
devices 118 may interact with the IT system 116. The onsite user devices 118 may include any
number of user devices, for example, stationary user devices intended to be stationed at the
drilling rig 102 and/or portable user devices. In some embodiments, the onsite user devices 118
may include a desktop, a laptop, a smartphone, a personal data assistant (PDA), a tablet
component, a wearable computer, or other suitable devices. In some embodiments, the onsite
user devices 118 may communicate with the rig computing resource environment 105 of the
drilling rig 102, the remote computing resource environment 106, or both.

One or more offsite user devices 120 may also be included in the system 100. The offsite user
devices 120 may include a desktop, a laptop, a smartphone, a personal data assistant (PDA), a
tablet component, a wearable computer, or other suitable devices. The offsite user devices 120
may be configured to receive and/or transmit information (e.g., monitoring functionality) from
and/or to the drilling rig 102 via communication with the rig computing resource environment.
In some embodiments, the offsite user devices 120 may provide control processes for controlling operation of the various systems of the drilling rig 102. In some embodiments, the offsite user devices 120 may communicate with the remote computing resource environment 106 via the network 108.

The systems of the drilling rig 102 may include various sensors, actuators, and controllers (e.g., programmable logic controllers (PLCs)). For example, the downhole system 110 may include sensors 122, actuators 124, and controllers 126. The fluid system 112 may include sensors 128, actuators 130, and controllers 132. Additionally, the central system 114 may include sensors 134, actuators 136, and controllers 138. The sensors 122, 128, and 134 may include a camera, a pressure sensor, a temperature sensor, a flow rate sensor, a vibration sensor, a current sensor, a voltage sensor, a resistance sensor, a gesture detection sensor or device, a voice actuated or recognition device or sensor, or other suitable sensors.

The sensors described above may provide sensor data to the rig computing resource environment 105 (e.g., to the coordinated control device 104). For example, downhole system sensors 122 may provide sensor data 140, the fluid system sensors 128 may provide sensor data 142, and the central system sensors 134 may provide sensor data 144. The sensor data 140, 142, and 144 may include, for example, equipment operation status (e.g., on or off, up or down, set or release, etc.), drilling parameters (e.g., depth, hook load, torque, etc.), auxiliary parameters (e.g., vibration data of a pump) and other suitable data. In some embodiments, the acquired sensor data may include or be associated with a timestamp (e.g., a date, time or both) indicating when the sensor data was acquired. Further, the sensor data may be aligned with a depth or other drilling parameter.

Acquiring the sensor data at the coordinated control device 104 may facilitate measurement of the same physical properties at different locations of the drilling rig 102. In some embodiments, measurement of the same physical properties may be used for measurement redundancy to enable continued operation of the well. In yet another embodiment, measurements of the same physical properties at different locations may be used for detecting equipment conditions among different physical locations. The variation in measurements at different locations over time may be used to determine equipment performance, system performance, scheduled
maintenance due dates, and the like. For example, slip status (e.g., in or out) may be acquired from the sensors and provided to the rig computing resource environment 105. In another example, acquisition of fluid samples may be measured by a sensor and related with bit depth and time measured by other sensors. Acquisition of data from a camera sensor may facilitate detection of arrival and/or installation of materials or equipment in the drilling rig 102. The time of arrival and/or installation of materials or equipment may be used to evaluate degradation of a material, scheduled maintenance of equipment, and other evaluations.

The coordinated control device 104 may facilitate control of individual systems (e.g., the central system 114, the downhole system, or fluid system 112, etc.) at the level of each individual system. For example, in the fluid system 112, sensor data 128 may be fed into the controller 132, which may respond to control the actuators 130. However, for control operations that involve multiple systems, the control may be coordinated through the coordinated control device 104. Examples of such coordinated control operations include the control of downhole pressure during tripping. The downhole pressure may be affected by both the fluid system 112 (e.g., pump rate and choke position) and the central system 114 (e.g., tripping speed). When it is desired to maintain certain downhole pressure during tripping, the coordinated control device 104 may be used to direct the appropriate control commands.

In some embodiments, control of the various systems of the drilling rig 102 may be provided via a three-tier control system that includes a first tier of the controllers 126, 132, and 138, a second tier of the coordinated control device 104, and a third tier of the supervisory control system 107. In other embodiments, coordinated control may be provided by one or more controllers of one or more of the drilling rig systems 110, 112, and 114 without the use of a coordinated control device 104. In such embodiments, the rig computing resource environment 105 may provide control processes directly to these controllers for coordinated control. For example, in some embodiments, the controllers 126 and the controllers 132 may be used for coordinated control of multiple systems of the drilling rig 102.

The sensor data 140, 142, and 144 may be received by the coordinated control device 104 and used for control of the drilling rig 102 and the drilling rig systems 110, 112, and 114. In some embodiments, the sensor data 140, 142, and 144 may be encrypted to produce encrypted sensor data 146. For example, in some embodiments, the rig computing resource environment 105
may encrypt sensor data from different types of sensors and systems to produce a set of encrypted sensor data 146. Thus, the encrypted sensor data 146 may not be viewable by unauthorized user devices (either offsite or onsite user device) if such devices gain access to one or more networks of the drilling rig 102. The encrypted sensor data 146 may include a timestamp and an aligned drilling parameter (e.g., depth) as discussed above. The encrypted sensor data 146 may be sent to the remote computing resource environment 106 via the network 108 and stored as encrypted sensor data 148.

The rig computing resource environment 105 may provide the encrypted sensor data 148 available for viewing and processing offsite, such as via offsite user devices 120. Access to the encrypted sensor data 148 may be restricted via access control implemented in the rig computing resource environment 105. In some embodiments, the encrypted sensor data 148 may be provided in real-time to offsite user devices 120 such that offsite personnel may view realtime status of the drilling rig 102 and provide feedback based on the real-time sensor data. For example, different portions of the encrypted sensor data 146 may be sent to offsite user devices 120. In some embodiments, encrypted sensor data may be decrypted by the rig computing resource environment 105 before transmission or decrypted on an offsite user device after encrypted sensor data is received.

The offsite user device 120 may include a thin client configured to display data received from the rig computing resource environment 105 and/or the remote computing resource environment 106. For example, multiple types of thin clients (e.g., devices with display capability and minimal processing capability) may be used for certain functions or for viewing various sensor data.

The rig computing resource environment 105 may include various computing resources used for monitoring and controlling operations such as one or more computers having a processor and a memory. For example, the coordinated control device 104 may include a computer having a processor and memory for processing sensor data, storing sensor data, and issuing control commands responsive to sensor data. As noted above, the coordinated control device 104 may control various operations of the various systems of the drilling rig 102 via analysis of sensor data from one or more drilling rig systems (e.g. 110, 112, 114) to enable coordinated control between each system of the drilling rig 102. The coordinated control device 104 may execute
control commands 150 for control of the various systems of the drilling rig 102 (e.g., drilling rig systems 110, 112, 114). The coordinated control device 104 may send control data determined by the execution of the control commands 150 to one or more systems of the drilling rig 102. For example, control data 152 may be sent to the downhole system 110, control data 154 may be sent to the fluid system 112, and control data 154 may be sent to the central system 114. The control data may include, for example, operator commands (e.g., turn on or off a pump, switch on or off a valve, update a physical property setpoint, etc.). In some embodiments, the coordinated control device 104 may include a fast control loop that directly obtains sensor data 140, 142, and 144 and executes, for example, a control algorithm. In some embodiments, the coordinated control device 104 may include a slow control loop that obtains data via the rig computing resource environment 105 to generate control commands.

In some embodiments, the coordinated control device 104 may intermediate between the supervisory control system 107 and the controllers 126, 132, and 138 of the systems 110, 112, and 114. For example, in such embodiments, a supervisory control system 107 may be used to control systems of the drilling rig 102. The supervisory control system 107 may include, for example, devices for entering control commands to perform operations of systems of the drilling rig 102. In some embodiments, the coordinated control device 104 may receive commands from the supervisory control system 107, process the commands according to a rule (e.g., an algorithm based upon the laws of physics for drilling operations), and/or control processes received from the rig computing resource environment 105, and provides control data to one or more systems of the drilling rig 102. In some embodiments, the supervisory control system 107 may be provided by and/or controlled by a third party. In such embodiments, the coordinated control device 104 may coordinate control between discrete supervisory control systems and the systems 110, 112, and 114 while using control commands that may be optimized from the sensor data received from the systems 110, 112, and 114 and analyzed via the rig computing resource environment 105.

The rig computing resource environment 105 may include a monitoring process 141 that may use sensor data to determine information about the drilling rig 102. For example, in some embodiments the monitoring process 141 may determine a drilling state, equipment health, system health, a maintenance schedule, or any combination thereof. In some embodiments, the rig computing resource environment 105 may include control processes 143 that may use the
sensor data 146 to optimize drilling operations, such as, for example, the control of drilling equipment to improve drilling efficiency, equipment reliability, and the like. For example, in some embodiments the acquired sensor data may be used to derive a noise cancellation scheme to improve electromagnetic and mud pulse telemetry signal processing. The control processes 143 may be implemented via, for example, a control algorithm, a computer program, firmware, or other suitable hardware and/or software. In some embodiments, the remote computing resource environment 106 may include a control process 145 that may be provided to the rig computing resource environment 105.

The rig computing resource environment 105 may include various computing resources, such as, for example, a single computer or multiple computers. In some embodiments, the rig computing resource environment 105 may include a virtual computer system and a virtual database or other virtual structure for collected data. The virtual computer system and virtual database may include one or more resource interfaces (e.g., web interfaces) that enable the submission of application programming interface (API) calls to the various resources through a request. In addition, each of the resources may include one or more resource interfaces that enable the resources to access each other (e.g., to enable a virtual computer system of the computing resource environment to store data in or retrieve data from the database or other structure for collected data).

The virtual computer system may include a collection of computing resources configured to instantiate virtual machine instances. A user may interface with the virtual computer system via the offsite user device or, in some embodiments, the onsite user device. In some embodiments, other computer systems or computer system services may be utilized in the rig computing resource environment 105, such as a computer system or computer system service that provisions computing resources on dedicated or shared computers/servers and/or other physical devices. In some embodiments, the rig computing resource environment 105 may include a single server (in a discrete hardware component or as a virtual server) or multiple servers (e.g., web servers, application servers, or other servers). The servers may be, for example, computers arranged in any physical and/or virtual configuration.

In some embodiments, the rig computing resource environment 105 may include a database that may be a collection of computing resources that run one or more data collections. Such
data collections may be operated and managed by utilizing API calls. The data collections, such as sensor data, may be made available to other resources in the rig computing resource environment or to user devices (e.g., onsite user device 118 and/or offsite user device 120) accessing the rig computing resource environment 105. In some embodiments, the remote computing resource environment 106 may include similar computing resources to those described above, such as a single computer or multiple computers (in discrete hardware components or virtual computer systems).

In some embodiments, the methods of the present disclosure may be executed by a computing system. Figure 5 illustrates an example of such a computing system 500, in accordance with some embodiments. The computing system 500 may include a computer or computer system 501A, which may be an individual computer system 501A or an arrangement of distributed computer systems. The computer system 501A includes one or more analysis modules 502 that are configured to perform various tasks according to some embodiments, such as one or more methods disclosed herein. To perform these various tasks, the analysis module 502 executes independently, or in coordination with, one or more processors 504, which is (or are) connected to one or more storage media 506. The processor(s) 504 is (or are) also connected to a network interface 505 to allow the computer system 501A to communicate over a data network 509 with one or more additional computer systems and/or computing systems, such as 501B, 501C, and/or 501D (note that computer systems 501B, 501C and/or 501D may or may not share the same architecture as computer system 501A, and may be located in different physical locations, e.g., computer systems 501A and 501B may be located in a processing facility, while in communication with one or more computer systems such as 501C and/or 501D that are located in one or more data centers, and/or located in varying countries on different continents).

A processor may include a microprocessor, microcontroller, processor module or subsystem, programmable integrated circuit, programmable gate array, or another control or computing device.

The storage media 506 may be implemented as one or more computer-readable or machine-readable storage media. Note that while in the example embodiment of Figure 5 storage media 506 is depicted as within computer system 501A, in some embodiments, storage media 506 may be distributed within and/or across multiple internal and/or external enclosures of
computing system 501A and/or additional computing systems. Storage media 506 may include one or more different forms of memory including semiconductor memory devices such as dynamic or static random access memories (DRAMs or SRAMs), erasable and programmable read-only memories (EPROMs), electrically erasable and programmable read-only memories (EEPROMs) and flash memories, magnetic disks such as fixed, floppy and removable disks, other magnetic media including tape, optical media such as compact disks (CDs) or digital video disks (DVDs), BLU-RAY® disks, or other types of optical storage, or other types of storage devices. Note that the instructions discussed above may be provided on one computer-readable or machine-readable storage medium, or alternatively, may be provided on multiple computer readable or machine-readable storage media distributed in a large system having possibly plural nodes. Such computer-readable or machine-readable storage medium or media is (are) considered to be part of an article (or article of manufacture). An article or article of manufacture may refer to any manufactured single component or multiple components. The storage medium or media may be located either in the machine running the machine-readable instructions, or located at a remote site from which machine-readable instructions may be downloaded over a network for execution.

In some embodiments, the computing system 500 contains one or more rig control module(s) 508. In the example of computing system 500, computer system 501A includes the rig control module 508. In some embodiments, a single rig control module may be used to perform some or all aspects of one or more embodiments of the methods disclosed herein. In alternate embodiments, a plurality of rig control modules may be used to perform some or all aspects of methods herein.

It should be appreciated that computing system 500 is only one example of a computing system, and that computing system 500 may have more or fewer components than shown, may combine additional components not depicted in the example embodiment of Figure 5, and/or computing system 500 may have a different configuration or arrangement of the components depicted in Figure 5. The various components shown in Figure 5 may be implemented in hardware, software, or a combination of both hardware and software, including one or more signal processing and/or application specific integrated circuits.
Further, the steps in the processing methods described herein may be implemented by running one or more functional modules in information processing apparatus such as general purpose processors or application specific chips, such as ASICs, FPGAs, PLDs, or other appropriate devices. These modules, combinations of these modules, and/or their combination with general hardware are all included within the scope of protection of the invention.

Figure 3A illustrates a side, schematic view of a drilling rig 300, according to an embodiment. The drill rig 300 is positioned over a well, wherein a casing 341 is cemented with cement 342 in the well and a wellhead 340 is attached to the casing 341. A cellar 343 is dug around the wellhead 340. The wellhead 340 comprises a blow out preventer BOP 344, a bell nipple 345, and a rotating control device RCD 346. A flow out line 347 extends from the bell nipple 345. The drilling rig (or "rig system") 300 may include a rig floor 302, through which a drill string 304 is received. The drill string 304 is deployed into, so as to form, the wellbore. The drill string 304 is rotated via a drilling device, such as a top drive 306, although other drilling equipment such as rotary table 303 may be employed instead of or in addition to a top drive 306. A quill 307 may extend from the bottom of the top drive 306 to allow the connection to the drill-string 304. In some operations, the drill-string 304 may be supported by slip 305 engaged in the rotary-table 303.

The top drive 306 is movable via a drill line 308 and a drawworks 310. The drawworks 310 operates to spool or unspool the drill line 308 to a fast sieve 309, and thereby raise or lower the top drive 306 in a mast 312, relative to the rig floor 302. The top drive 306 is guided along the mast 312, and the mast 312 bears the weight of the drill line 308 and the top drive 306 through the crown block 314 at the top of the mast 312. The mast 312 transmits this weight to the ground via the rig substructure 316. Further, the mast 312 bears the reactionary torque from the top drive 306 rotating the drill string 304.

The mast 312 may have an asymmetric, e.g., U-shaped geometry. The open end of the U-shape may face the inclined slide 318 of the rig 300, as shown, which may facilitate loading new drill pipes into the mast 312 for connection with the drill string 304. A catwalk 317 delivers new pipes to the rig floor 302. The new pipes may be loaded and made-up into a pipe stand 319 using a pipe handler 320, as shown, although a single-joint elevator or another structure may also or instead be used. Further, a block retractor (or "block retraction system") 322 may be
provided, which may include one or more vertically-extending rails along the U-shaped
geometry of the mast. The block retraction system 322 may also include a rigid arm, or
potentially a flexible cable, which may serve to push or pull the travelling block 324
horizontally relative to mast 312, and thus adjust the horizontal position of the top drive 306.

As shown in Figure 4A, because the mast 312 has an asymmetric geometry, the mast may tend
to bend unevenly under the load of the top drive 306 and/or the drill string 304 (when hanging
onto the top-drive 306. As the mast 312 bends, the travel path 328 of the quill 307 becomes
inclined (or even curved) relative to the well axis 326. Further, the ground beneath the rig
substructure 316 may compact unevenly during drilling. Compacted earth 336 may cause the
rig substructure 316 to tilt as it settles unevenly on the ground. A substructure axis 325 may
become inclined relative to the well axis 326. These circumstances may be additive, e.g., the
rig compaction and the uneven bending may build on one another, or they may be subtractive.
However, the uneven bending and/or uneven compaction may result in the travel path 328
along which the quill 307 and travelling block 324 move in the mast 312 being angled and/or
even curved with respect to the well axis 326. This is called the "loaded" travel path 328. In
particular, a quill axis 327 may become displaced relative to the well axis 326, wherein the
misalignment shown in Figure 3A is due to activation of the block retractions system 322.
Accordingly, the present disclosure may employ a method for dynamically adjusting the lateral
position of the travelling block 324 (and thus the top drive 306) using the retraction system 322
while moving the top drive 306 as part of the drilling operation. The main objective of such
method is to insure that the axis of the quill 307 moves along the axis 326 of the well. In one
embodiment, the method includes 2 steps. The first step is the determination of the travel path
of the travelling-block and/or top drive in the mast when moving up or down without activation
of the block retraction system 322: such path is the "uncorrected" travel path of the travelling
block 324. The second step is the application of the required effect (correction) on the travel
block 324 by the retraction system 322 to insure a linear vertical path of the top-drive when
moving up/down in the mast 312. The travelling block 324 may then move along the
"corrected" travel path.

Figure 3B illustrates a side, schematic view of a drilling rig 300, according to an alternate
embodiment that is similar to the drilling rig shown in Figure 3A. In this embodiment, block
retraction system 322 is located at the top of the mast 312 so as to move the crown block 314
relative to the mast 312. In this embodiment, the required effect (correction) on the travel block 324 to insure a linear vertical path of the top-drive 306 when moving up/down in the mast 312, is done by moving the crown block 314 with the retraction system 322. When the crown block 314 is positioned on the well axis 326, the travelling block 324 may then move along the "corrected" travel path.

In a further embodiment of the invention, the retraction system 322 comprises a combination of the retraction systems illustrated in Figures 3A and 3B. In this embodiment, both the crown block 314 and the travelling block 324 may be moved to and retained in "corrected" positions more in line with the well axis 326 to insure a linear vertical path of the top-drive 306 when moving up/down in the mast 312.

As shown in Figure 4B, because the mast 312 has an asymmetric geometry, the mast may tend to bend unevenly under the load of the top drive 306 and/or the drill string 304 (when hanging onto the top-drive 306. In this embodiment, block retraction system 322 is located at the top of the mast 312 so as to move the crown block 314 relative to the mast 312. In this embodiment, the required effect (correction) on the travel block 324 to insure a linear vertical path of the top-drive 306 when moving up/down in the mast 312, is done by moving the crown block 314 with the retraction system 322. When the crown block 314 is positioned on the well axis 326, the travelling block 324 may then move along the "corrected" travel path.

In a further embodiment of the invention, the retraction system 322 comprises a combination of the retraction systems illustrated in Figures 4A and 4B. In this embodiment, both the crown block 314 and the travelling block 324 may be moved to and retained in "corrected" positions more in line with the well axis 326 to insure a linear vertical path of the top-drive 306 when moving up/down in the mast 312.

In order to execute such a method, the rig system may include a method to determine the distance X between the axis 326 of the well versus the default travel path 328 of the quill 307 when travelling vertically in the mast 312. The travel path 328 depends directly on the load in the mast and the ground compaction 336. It is supposed that the travel path 328 for the quill 307 and/or travel block 324 is in a vertical plane passing by the axis 326 of the well and perpendicular to the direction of the movement performed during block retract (which is
typically opposed to the direction of the catwalk 317). This travel path 328 is the location of point "P" which can be located by some 2D coordinate systems. In particular, the 2D coordinates can be determined by the length "L" from a reference point and the angle "a" in reference to a given horizon. Any laser generator, such as a theodolite associated with a laser ranging system can deliver these two measurements. In some embodiments, this may be provided by the theodolite 334 and/or laser ranging systems, which may be located at a stationary position some distance away from the rig 300, as shown in Figure 4A. In another embodiment, the 2D coordinate system may be determined by the arc "E" and the radius "L." The arc "E" is obtained from the hook-position which is typically tracked on a drilling rig versus the rig floor 302. The radius "L" may be obtained from a pulsed laser system. In another embodiment (see Figure 5B), two theodolites 334A and 334B are shown installed in the plane of flexing of the mast 312 to allow a determination of the position of the point "P" of the travel path 328 of the travelling block 324 and/or the quill 307. The relative positions of the two theodolites 334A and 334B must be known. In the Figure 5B, they are represented on the same elevation and separated from each other at a distance "D." The solution method for the proper determination of the position of "P" from the measured angles a1 and a2 is well known by persons of skill in the art. In a further embodiment, as shown in Figure 5C, two laser ranging systems 370A and 370B are enabled to measure distances L1 and L2 to the position "P" of the travel path 328 of the travelling block 324 and/or the quill 307. In still further embodiments of the invention a combination of angle measurement and distance measurement devices may be used to determine the position "P" of the travel path 328 of the travelling block 324 and/or the quill 307 relative to the well axis 326.

Embodiments of the invention may use any laser generator known to persons of skill, such as a theodolite, a laser ranging system, etc.

For example, the theodolite and/or laser ranging system 334 may be stationed on a concrete pad formed at a range of about 100 meters away from the rig floor 302. The theodolite and/or laser ranging system 334 may bounce a laser beam 335 off a reflector 333 to determine a distance between the theodolite and/or laser ranging systems 334 and the reflector 333. The 2D coordinates of the point "P" on the travel path defined by the reflector 333 can be determined as "L" and "a" if a combined theodolite and laser ranging system is being used or as "L" and "E" if a pulsed laser system is associated with the hook-position measurement (such
as a drawwork encoder 315). Such determination can be determined for multiple points "P" along the travel path 328. When no correction is performed by the block retraction system 322, this travel path 328 is called the "uncorrected" travel path.

It should be noted that the "uncorrected" travel path depends on the lifted force by the travelling block 324, as the mast 312 may bend more and the earth compaction 336 may also be affected with a change in the lifted force (hookload). So the "uncorrected" travel path is associated with a measured lifted force or "hookload" supported in the mast 312. The rig system 300 may also employ a determination of the hookload supported by the mast 312. This hookload may be may be measured on the deadline 330 of the drawworks 310 via a hookload sensor 331, as shown in Figure 4A, but could also be a load measured directly by the top drive 306, crown block 314, etc. Such hookload may unevenly bend the mast 312.

The "uncorrected" travel path is a set of points "P," wherein for each position "P" on the travel path 328, the corresponding position "P'" on the well axis 326 can be determined by geometry. Then the horizontal offset "X" can then be determined. Such information corresponding to the N positions of the travelling block 324 and/or top drive 306 can be reformatted as N pairs of "elevation above the rig floor" (as measured by the hook-position) and the correction from vertical "X" as determined above. This would produce a correction matrix of N x 2. Such matrix is determined for a defined hookload. The corrections may be referred to the mast itself or the guidance rail 313 of the retraction system 322, as shown in Figure 4A, by applying a horizontal correction (W - X), where W is the distance between the well axis 326 and the guidance rail 313. W is called the "required retraction." This provides a matrix of N x 2 of "required retraction" versus "block elevation above the rig floor." Such information may depend on the hookload.

When that matrix is available after the first step (travel-path determination) of the overall process, then correction can be applied. The block retraction system 322 may then be controlled to extend/retract the travelling block 324 and/or top drive 306 to/from the guide rails 313 so that the quill axis 327 is collinear with the well axis 326 (see Figure 3A). Typically, the hook position is continuously determined via the encoder 315 on the drawwork 310 to determine the "block elevation above the rig floor." Then the required concretion is determined
based on the matrix. Interpolation may be required between points of the matrix. The "required correction" is then applied via the retraction system 322.

The usage of the 2 steps methods (determination of "uncorrected" travel path under load, followed by application of correction) as described above allows use of the theodolite and/or the ranging system during a limited time. This may be advantageous as the usage of these devices may require the support of technical experts. In another embodiment, the usage of the theodolite and/or the ranging systems may be continuous so that there is no need of a "correction" table. The retraction system is controlled in a continuous fashion to insure that the axis 327 of the quill 307 is aligned with the axis 326 of the well.

Such process may be performed by rig computer 105, which may be part of the rig control system 100 discussed above. In turn, the rig control system 100 may determine a distance to from the guide rails 313 of the mast 312 that the top drive 306 is to be located, based on its vertical position. The rig computer may control the block retraction system 322, which may push and/or pull the travelling block 324 as it moves along the mast 312, so as to laterally position the top drive 306 along the well axis 326 (e.g., such that the top drive 306 "follows" the well axis 326 at a plurality of points, e.g., continuously, along the travel of the top drive 306). It will be appreciated that the distance between the top drive 306 and the guide rails 313 of the mast 312 may be continuously, or at relatively short intervals, adjusted during the movement of the top drive 306, so as to maintain the top drive 306 movement along the well axis 326.

Accordingly, the rig system 300 may receive information representing the hookload, elevation of the top drive 306, and lateral position of the top drive 306. The rig computer 105 may then employ this information to determine a distance from the guide rail 313 of the mast 312 that the top drive 306 should be, at various elevations (or adjusted continuously) in the mast 312, depending on the hookload.

Figure 5A illustrates some of the deformations associated with rig operation, as well as the paths potentially followed by the travelling block. In ideal condition, the quill 307 of the top drive 306 should move in the mast along the axis 326 of the well-bore. Difference of ground compaction (shown as 336B and 336A) creates some tilting of the rig, wherein such tilting could
be determined by inclinometer 337 connected to the rig base 350. Furthermore, the rig substructures 316_A and 316_B may be compressed by the effect of hookload: this effect may generate differences of elevation RFA and RFB in the rig-floor 302 as the loads in the substructures 316A and 316B may not be balanced. This difference of elevation creates additional inclination. The rig-floor inclination $\beta$ may be different than the inclination $\gamma$ of the base system 350. The mast axis 338 would normally be perpendicular to the rig floor. The mast axis 338 would normally be the travel path of the travelling block 324 and/or quill 307 when the hookload is low.

If the hookload is at a certain defined value, the mast bends (flexes) elastically and the travel path of the travelling block 324 and/or quill 307 becomes the path 328T ("T" for total deformation including ground differential compaction 336 and the elastic deformations of the rig. The elastic deformation of the rig has two key components:

(1) the effect of the differences of deformation of the substructure 316. This substructure deformations modify the rig floor elevation RF_A and RF_B, generating some tilting of the rig floor as well as the mast; and

(2) the flexing of the mast under hookload effect.

In case of the rig being installed on very rigid ground, the ground deformation effects 336_B and 336A can be similar (and even negligible) so that the inclination $\gamma$ measured by the inclinometers 337 is small (or close to null). In such condition, only the two types of elastic deformations of the rig affect the travel path of the travelling block 324 and/or quill 307, which is defined as 328R (index "R" for "rig deformation).

In practical terms, the rig deformation 328R depends on the hookload and should be reproducible. Such deformation could be measured by a combined theodolite and laser ranging system in a defined stable condition (such as new rig on tick concrete pad). This would allow generation of a matrix of n-lines with columns including the "required correction W" for the given hookload and elevation, as shown in Table 1.

<table>
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<th>Block Elevation</th>
<th>Hookload 1</th>
<th>Hookload 2</th>
<th>Hookload 3</th>
<th>Hookload 4</th>
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<td>W1_2</td>
<td>W1_3</td>
<td>W1_4</td>
<td></td>
</tr>
</tbody>
</table>
The "required correction W" for the given hookloads and elevations are characteristic of the rig. Interpolation may be performed to obtain the "required correction W" between measured data points, in relation to block elevation and hookload.

When the rig operates on deformable ground, the rig base 350 may generate ground deformations 336A and 336B so that inclination γ occurs at/between rig bases. Such inclination a would add tilt γ in the mast (defined by the axis 339). This additional tilting may induce the need for an additional correction WT for the retraction system.

\[
WT = "\text{block-elevation} \sin(\gamma)"
\]

The total correction W to apply by the retraction system would be WT + Wij, wherein Wij may be obtained from the matrix in Table 1, depending on block elevation and hookload.

When using such approach, a theodolite may only be necessary to create the matrix for "required correction W." During drilling operation, the computer 105 may only need to measure hookload, block elevation and inclination γ (by inclinometer 337).

Figure 6A illustrates a perspective view of a block retractor 322 capable of use with the invention. The retractor has a carriage 360 from which extend four guide brackets 361. Of course, the guide brackets mate with and glide along guide rails 313 in the mast 312 (see Figures 3 and 4). Upper and lower arms 362 and 363 extend from the carriage for mounting the top drive 306 and/or travelling block 324 to the carriage 360. Pistons 364 extend between the carriage 360 and the lower arms 363 to move the top drive 306 and/or travelling block 324 between a retracted position (see Figure 6B) and an extended position (see Figure 6C).

Although bending in a single plane, and commensurately, adjusting the position of the top drive 306 in a single axis, is shown, it will be appreciated that such bending and adjusting may be extended to two dimensions consistent with the present disclosure. For example, a second

<table>
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<th>E2</th>
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<th>W2_3</th>
<th>W2_4</th>
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<td>...</td>
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</table>

**TABLE 1.**
device for determining the lateral position of the top drive 306 (e.g., another theodolite and/or laser ranging systems 334 or another inclinometer positioned 90 degrees from the first one shown) may be provided, which may allow to determine the position of the top drive 306 along an axis extending perpendicular the present figure. The combination of the measurements from the two sensors, e.g., theodolites and/or laser ranging systems 334, may result in a determination of the position of the top drive 306 in the horizontal plane, rather than along a single axis. Further, a second guide rail and block retraction system may be provided in the mast, e.g., also rotated 90 degrees from the guide rail shown. Accordingly, the position of the travelling block 324, and thus the top drive 306, may also be adjusted in the horizontal plane.

Figure 7 illustrates a side view of a drill rig 300. The drill rig mast 312 extends vertically from a substructure 316 with a rig floor 302 between. The substructure 316 is supported by a rig base 350, which rest upon the ground. The rig base 350 generally is a square shape and is positioned around the wellbore and cellar 343 (see Figures 3 and 4). At each of the four corners of the rig base 350, there is a jack 351. The jacks 351 are capable of lifting the entire drill rig 300 off the ground, when extended in unison. The jacks 351 may be hydraulic jacks or any other jacks known to persons of skill. The theodolite and/or laser ranging systems 334 is positioned on the ground at a distance from the drill rig 300 so as to direct a laser beam 335 at a reflector 333 located at the top of the mast 312. A computer may use distance information provided by the theodolite and/or laser ranging systems 334 to determine whether the top of the mast 312 is positioned in line with the well axis 326. If the top of the mast 312 is not positioned in line with the well axis 326, the two jacks on the catwalk 317 side of the rig 300 may be extended, or the two jacks on the drawwork 310 side of the rig 300 may be extended, to reposition the top of the mast 312 farther away from or closer to the theodolite and/or laser ranging systems 334, respectively, until the top of the mast 312 is again positioned in line with the well axis 326. In a further embodiment, a second theodolite and/or laser ranging systems may be positioned on the ground at a distance from the drill rig 300, wherein lines from the theodolites and/or laser ranging systems to the drill rig 300 are perpendicular. The second theodolite and/or laser ranging systems may be used to reposition the top of the mast 312 in a plane defined by the well axis 326 and the second theodolite and/or laser ranging systems by extending either the jacks 351 in the foreground or the jacks in the background (not visible) in Figure 7. With two theodolites and/or laser ranging systems 334, the top of the mast 312 may
be positioned directly over the well in line with the well axis 326, by extending one or more of the jacks 351.

In another embodiment, inclinometers may be installed on the base 350 of the drilling rig to measure the tilting effect of the base in two perpendicular directions. These measurements determine the effect of the difference of earth compaction 336. These measurement can be used to determine the correction to perform with the rig jack 351 to correct the inclinations in the two directions so that the effect of these compaction is cancelled.

Rig jack 351 may be any type of jack known to persons of skill in the art. For example, they may be hydraulic rig jacks, such as those used to walk the rig from one well bore to another, where operations are conducted with respect to more than one wellbore on a particular pad site. Further, a lock may be implemented relative to each jack to hold the jack in a particular position. Hydraulic jacks, for example, may leak fluid and therefore not maintain the jack at a particular height under the extremely heavy load of the drill rig. Thus, a locking mechanism may be implemented to carry the weight of the drill rig once the jack has lifted it to a particular height. Each time the jack is adjusted, the lock may be released to allow the jack to reposition the drilling rig and once repositioned, the jack may again be fixed in the position by the lock. As shown in Figure 8, the jack 351 may comprise housing 353 that is fixed to the rig base 350. A piston 352 extends from the housing 353, and a pad 354 is attached to the end of the piston 352. A lock 355 extends between the pad 354 and the rig base 350 to lock the drill rig at a particular height once set by the jack 351.

In an alternative embodiment, the two theodolites and/or laser ranging systems 334 may be used by the computer 105 to determine the horizontal position of the top drive 306 relative to the well axis 326 and the four jacks 351 may be used to tilt the drill rig 300 to reposition the top drive 306.

In a further embodiment of the invention, the drive system may be a turn table in the rig floor that rotates a Kelly around the drill string. Because the rig floor is supported several feet above the ground by the rig substructure, the turntable may become off center when the drill rig settles into the ground due to uneven compaction of the dirt. Two theodolites and/or laser ranging systems 334 may be used by the computer 105 to determine the horizontal position of the turn
table and Kelly. The four jacks 351 may be used to relocate the turn table and Kelly directly over the well bore to align with the well axis.

A further embodiment of the invention comprises a drill rig system for drilling a wellbore wherein the sensing of the position of the turning device comprises two primary theodolites positioned in the plane defined the flexing of the mast and two distances away from the turning device and two secondary theodolites positioned in a vertical plane perpendicular to the plane defined the flexing of the mast and two distances away from the turning device.

The foregoing description, for purpose of explanation, has been described with reference to specific embodiments. However, the illustrative discussions above are not intended to be exhaustive or to limit the invention to the precise forms disclosed. Many modifications and variations are possible in view of the above teachings. Moreover, the order in which the elements of the methods described herein are illustrate and described may be re-arranged, and/or two or more elements may occur simultaneously. The embodiments were chosen and described in order to best explain the principals of the invention and its practical applications, to thereby enable others skilled in the art to best utilize the invention and various embodiments with various modifications as are suited to the particular use contemplated. Additional information supporting the disclosure is contained in the appendix attached hereto.
CLAIMS

What is claimed is:

1. A drill rig system for drilling a wellbore in the earth, the drill rig system comprising:
   - a drill string turning device;
   - a sensor of the position of the turning device relative to a well axis; and
   - a mover of the turning device to a position on the well axis.

2. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the turning device comprises a top drive.

3. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the turning device comprises a turn table and kelly.

4. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the sensor of the position of the turning device comprises a theodolite and a laser ranging system positioned a distance away from the turning device.

5. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the sensor of the position of the turning device comprises a first sensor positioned a distance away from the turning device and a second sensor positioned another distance away from the turning device, wherein the first sensor, the well axis, and the second sensor form an angle of approximately 90 degrees at the well axis in a plane perpendicular to the well axis.

6. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the sensor of the position of the turning device comprises first and second theodolites positioned in a plane defined by the flexing of the mast and two distances away from the turning device.

7. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the sensor of the position of the turning device comprises two primary theodolites positioned in the plane defined the flexing of the mast and two distances away from the turning device and two secondary theodolites positioned in a vertical plane perpendicular to the plane defined the flexing of the mast and two distances away from the turning device.
8. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the sensor of the position of the turning device comprises at least one inclinometer that detects an inclination of the mast.

9. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the sensor of the position of the turning device comprises a device that measures a position of the turning device relative to the mast, and wherein the drill rig system further comprises a sensor of the weight of the drill string turning device and a drill string suspended from the drill string turning device.

10. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the turning device comprises a top drive and the mover comprises arms that extend/retract from a carriage to move the top drive relative to a drill rig mast.

11. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the turning device comprises a top drive and the mover comprises a mover of a crown block relative to a drill rig mast.

12. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the turning device comprises a turn table and kelly and the mover comprises at least one jack of the drill rig.

13. A drill rig system for drilling a wellbore, as claimed in claim 1, wherein the mover comprises a carriage that extends/retracts the top drive relative to a drill rig mast and at least one jack of the drill rig.

14. A drill rig system for drilling a wellbore, as claimed in claim 1, further comprising a controller of the mover based on data from the sensor of the position.

15. A drill rig system for drilling a wellbore, as claimed in claim 1, further comprising a control system, wherein the control system records position data corresponding to the position of the turning device relative to a well axis where the data is taken with the turning device
at a plurality of mast elevations and the drill rig system being subject to a plurality of hookloads at each mast elevation,
wherein the control system commands the mover to move the turning device to a recorded position based on a measured mast elevation and a measured hookload compared to the plurality of mast elevations and the plurality of hookloads at which the position data was recorded.

16. A method for drilling a wellbore in the earth, the method comprising:
turning a drill string with a turning device;
determining the position of the turning device relative to a well axis; and
positioning the turning device on the well axis.

17. A method for drilling a wellbore as claimed in claim 16, wherein the turning comprises turning the drill string with a top drive.

18. A method for drilling a wellbore as claimed in claim 16, wherein the turning comprises turning the drill string with a turn table and kelly.

19. A method for drilling a wellbore as claimed in claim 16, wherein the determining the position of the turning device comprises: positioning a laser generator a distance away from the turning device, sensing a laser beam generated via the laser generator to determine the distance between the laser generator and the turning device, and measuring an angle between the laser beam and a reference constant.

20. A method for drilling a wellbore as claimed in claim 16, wherein the determining the position of the turning device comprises: positioning first and second laser generators a distance from each other, generating a first laser beam between the first laser generator and the turning device, generating a second laser beam between the second laser generator and the turning device, and measuring angles between each laser beam and a reference constant.

21. A method for drilling a wellbore as claimed in claim 16, wherein the determining the position of the turning device comprises: positioning first and second ranging systems a
distance from each other, measuring a distance between the first ranging system and the turning
device, and measuring a distance between the second ranging system and the turning device.

22. A method for drilling a wellbore as claimed in claim 16, wherein the turning comprises
turning the drill string with a top drive and the positioning comprises extending/retracting a
carriage of the top drive relative to a drill rig mast.

23. A method for drilling a wellbore as claimed in claim 16, wherein the turning comprises
turning the drill string with a turn table and Kelly and the positioning comprises jacking
portions of a drill rig.

24. A method for drilling a wellbore as claimed in claim 16, wherein the positioning
comprises extending/retracting a carriage of the top drive relative to a drill rig mast and jacking
portions of a drill rig.

25. A method for drilling a wellbore as claimed in claim 16,
wherein the determining the position of the turning device relative to a well axis comprises
determining distances between the turning device and the well axis at a plurality of mast
elevations and a plurality of hookloads at each mast elevation, and

26. A drill rig system for drilling a wellbore in the earth, the drill rig system comprising:
a drill rig comprising:
a substructure supporting a rig floor and a mast extending vertically above the rig floor;
a top drive supported by a line spooled between a crown block and a travelling block,
a carriage that is guided by the guide rails on the mast, wherein the carriage has at least
one arm that extends/retracts to position the top drive farther/closer to the mast;
a first laser generator positioned to generate a laser beam relative to the top drive to determine
the top drive's position relative to a well axis; and
a controller of the at least one arm based on the top drive position determined by the laser
generator.

27. A drill rig system for drilling a wellbore, as claimed in claim 26, further comprising a
second laser generator positioned to generate a laser beam relative to the top drive to determine
the top drive's position relative to a well axis, wherein the second laser generator is positioned
a distance from the first laser generator.

28. A drill rig system for drilling a wellbore, as claimed in claim 26, further comprising a
plurality of jacks under the substructure that tilt the drill rig under control of the controller
based on the top drive position determined by the first laser generator.
INTERNATIONAL SEARCH REPORT

A. CLASSIFICATION OF SUBJECT MATTER

E21B 15/00(2006.01)i, E21B 3/02(2006.01)i, E21B 44/00(2006.01)i

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B 15/00; E21B 3/02; B23P 11/00; E21B ; E21B 19/16; E21B 19/00; E21B 7/04; E21B 44/00

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
Korean utility models and applications for utility models
Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & Keywords: rig, top drive, sensor, laser, tilt, mast, retract, drill string, turning device, well axis, position

C. DOCUMENTS CONSIDERED TO BE RELEVANT

<table>
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<th>Category</th>
<th>Citation of document, with indication, where appropriate, of the relevant passages</th>
<th>Relevant to claim No.</th>
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<td>US 2010-0065336 AI (WELLS et al.) 18 March 2010 See figures 1, 2A, 4B.</td>
<td>1-11, 13-22, 24-25</td>
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<td>US 2013-0341036 AI (FLUSCHE, MARK J.) 26 December 2013 See figures 1, 4.</td>
<td>12, 23, 26-28</td>
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<td>A</td>
<td>US 2005-0173154 AI (LESKO, GERALD) 11 August 2005 See figures 1-4</td>
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<td>A</td>
<td>WO 03-038229 A2 (CANTIG DRILLING TECHNOLOGY, LTD.) 08 May 2003 See page 5, line 2 - page 9, line 13; and figures 1-2, 3A-3C, 4.</td>
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Further documents are listed in the continuation of Box C.

See patent family annex.

* Special categories of cited documents:
  *"A"* document defining the general state of the art which is not considered to be of particular relevance
  *"E"* earlier application or patent but published on or after the international filing date
  *"L"* document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
  *"O"* document referring to an oral disclosure, use, exhibition or other means
  *"P"* document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search 19 May 2017 (19.05.2017)
Date of mailing of the international search report 19 May 2017 (19.05.2017)

Name and mailing address of the ISA/KR
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Authorized officer
HWANG, Chan Yoon
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Form PCT/ISA/210 (second sheet) (January 2015)
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