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(54) Title: SLIDE DRILLING SYSTEM AND METHOD

Type	Offset	Depth	Length	Area (ft ²)	Wt	Area (m ²)	Weight	Area (ft ²)
Pipe/Tool Joint	4.8750	3.5400	1335.7 000	2755.0 000	2229	7605	24 000 lbs/ft	254934
API	5.0000	3.4830	380.500	4500.934	9	439	1010.979 lbs	67925
Pipe/Tool Joint	4.8750	3.3400	4373.000	4470.434	731	931	14 000 lbs/ft	98998
API/Tool Joint	4.8750	2.5625	921.000	197.434	13	100	29 920 lbs/ft	7079
Pipe/Collar	4.8750	2.6875	2.400	105.544	1	87	0.2836 lbs/inch	4329
Pipe/Collar	4.7500	2.6875	30.875	102.874	15	88	0.2836 lbs/inch	4280
Stabilizer	5.7500	2.7500	5.460	71.201	5	71	0.2836 lbs/inch	2951
Pipe/Collar	4.7500	2.6875	30.700	90.744	13	66	0.2836 lbs/inch	2708
Stabilizer	4.5625	2.6875	2.900	35.874	2	53	0.2836 lbs/inch	1443
Stabilizer	5.7500	2.7500	5.400	32.994	5	21	0.2836 lbs/inch	1274
Sub PDM	5.7500	2.9000	26.834	37.584	45	46	1005.779 lbs	1002
	25.2225	28.2225	26.834	37.584	45	46	1005.779 lbs	1002

FIG. 4

(57) Abstract: A method for varying a weight on a drill bit in a wellbore. The method includes running a downhole tool into the wellbore on a drill string. The downhole tool includes a motor and a drill bit. The drill bit is rotated with the motor to drill the wellbore in a subsurface formation. An axial force applied to the drill string is varied from a surface location.

SLIDE DRILLING SYSTEM AND METHOD

Background

[0001] A downhole tool is used to drill a wellbore into a subsurface formation. The downhole tool may be run into the wellbore on a drill string. The downhole tool includes a motor that is configured to drive a drill bit, which cuts through the formation. When the downhole tool is drilling vertical wellbores, the weight of the drill string may provide sufficient weight on the drill bit (i.e., "WOB") for efficient drilling. However, when the downhole tool is drilling deviated or horizontal wellbores, at least a portion of the weight of the drill string may be supported by a casing or the wall of the wellbore. As a result, there may be insufficient weight on the drill bit for efficient drilling. In addition to this, as the downhole tool (e.g., the motor) slides within the wellbore, friction between the drill string and the casing or wall of the wellbore may further reduce the weight on the drill bit.

[0002] To remedy this, some downhole tools include an agitator and a shock sub. The agitator generates axial excitation in the drill string, which helps to transfer more of the weight of the drill string to the drill bit. Another technique is referred to as sliding. As the downhole tool (e.g. motor) slides within the wellbore, a cyclical torque is applied to the drill string at the surface to cause the drill string to move clockwise and counterclockwise in the wellbore. This movement of the drill string reduces axial friction, thereby transferring more of the weight of the drill string to the drill bit.

Summary

[0003] Embodiments of the present disclosure may provide a method for varying a weight on a drill bit in a wellbore. The method includes running a downhole tool into the wellbore on a drill string. The downhole tool includes a motor and a drill bit. The method also includes rotating the drill bit with the motor to drill the wellbore in a subsurface formation, and varying an axial force applied to the drill string from a surface location.

[0004] Embodiments of the disclosure may also provide a method for varying a weight on a drill bit in a wellbore. The method includes running a downhole tool into the wellbore on a drill string. The downhole tool includes a motor, a drill bit, and a vibration device. The method further includes rotating the drill bit with the motor to drill a deviated or horizontal portion of the

wellbore in a subsurface formation, causing the downhole tool to vibrate using the vibration device as the drill bit rotates, and varying an axial force applied to the drill string from a surface location.

[0005] Embodiments of the disclosure may further provide a system for varying a weight on a drill bit in a wellbore. The system includes a pulley system comprising a crown block having first and second lines wrapped at least partially thereabout, and a hook coupled to the pulley system. The hook is configured to support a drill string that extends into a wellbore, and the pulley system varies an axial force applied to the drill string as the drill string moves within the wellbore.

[0006] Embodiments of the present disclosure may also provide a system for varying a weight on a drill bit in a wellbore. The system includes a device located on or above a surface, a drill string extending into the wellbore from the surface. The drill bit is coupled to the drill string, and the device is configured to generate a pressure pulse and send the pressure pulse into the wellbore to cause the drill string to vibrate, thereby reducing friction as the drill string slides within the wellbore.

[0007] Embodiments of the disclosure may also provide a system for varying a weight on a drill bit in a wellbore. The system includes a device located on or above a surface, and a drill string extending into the wellbore from the surface. The drill bit is coupled to the drill string, and the device is configured to generate an electrical pulse and send the electrical pulse into the wellbore to cause drill string to vibrate, thereby reducing friction as the drill string slides within the wellbore.

[0008] Embodiments of the disclosure may provide a method for drilling a wellbore. The method includes running a drill string into a wellbore, with a drill bit being coupled to the drill string, vibrating the drill string as the drill string slides within the wellbore, and halting vibration of the drill string as the drill bit engages in rotational drilling.

Brief Description of the Drawings

[0009] 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:

[0010] Figure 1 illustrates a schematic view of a drilling rig and a control system, according to an embodiment.

[0011] Figure 2 illustrates a schematic view of a drilling rig and a remote computing resource environment, according to an embodiment.

[0012] Figure 3 illustrates a schematic view of a vibration tool in a wellbore, according to an embodiment.

[0013] Figure 4 illustrates a chart showing data related to an APG drill string configuration, according to an embodiment.

[0014] Figures 5-8 illustrate graphs showing wellbore trajectories, according to an embodiment.

[0015] Figures 9 illustrates a graph showing weight on bit (“WOB”) oscillation, according to an embodiment.

[0016] Figures 10 and 11 illustrate graphs showing simulation results of the rate of penetration (“ROP”) with and without the WOB variation drilling system, respectively, according to an embodiment.

[0017] Figures 12 and 13 illustrate graphs showing the surface WOB with and without the WOB variation drilling system, respectively, according to an embodiment.

[0018] Figures 14 and 15 illustrate graphs showing the downhole WOB with and without the WOB variation drilling system, respectively, according to an embodiment.

[0019] Figures 16 and 17 illustrate graphs showing the torque on the drill bit with and without the WOB variation drilling system, respectively, according to an embodiment.

[0020] Figure 18 illustrates a schematic view of the APG with a shock sub, according to an embodiment.

[0021] Figure 19 illustrates a graph showing the rate of penetration (“ROP”) with and without the WOB variation drilling system, according to an embodiment.

[0022] Figures 20-22 illustrate graphs showing the surface WOB, downhole WOB, and downhole torque on the drill bit, respectively, according to an embodiment.

[0023] Figures 23 and 24 illustrate graphs showing the frictional contact force in an axial direction without and with the WOB variation drilling system, respectively, according to an embodiment.

[0024] Figures 25-27 illustrate graphs showing a toolface history of the downhole tool without the WOB variation drilling system, with the WOB variation drilling system, and with the WOB variation drilling system and a vibration tool, respectively, according to an embodiment.

[0025] Figure 28 illustrates a graph showing the toolface history of the downhole tool with the WOB variation drilling system, according to an embodiment.

[0026] Figure 29 illustrates a schematic view of an embodiment of the WOB variation drilling system, according to an embodiment.

[0027] Figure 30 illustrates a graph showing the hookload with the WOB variation drilling system, according to an embodiment.

[0028] Figure 31 illustrates a graph showing the velocity of a drill pipe moving up and down at the surface due to action of the WOB variation drilling system, according to an embodiment.

[0029] Figure 32 illustrates a graph showing cyclic displacement of the drill pipe at the surface due to the action of the WOB variation drilling system, according to an embodiment.

[0030] Figure 33 illustrates a graph showing the tensile stress in the drill pipe near the surface due to the action of the WOB variation drilling system, according to an embodiment.

[0031] Figure 34 illustrates a schematic view of a computing system, according to an embodiment.

Detailed Description

[0032] 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.

[0033] 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 only used to distinguish one element from another. For example, a first object could be termed a second object or step, and, similarly, a second object could be termed a first object or step, without departing from the scope of the present disclosure.

[0034] The terminology used in the description of the invention 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.

[0035] 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.

[0036] 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).

[0037] 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.

[0038] 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.

[0039] 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.

[0040] 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.

[0041] 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.

[0042] 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).

[0043] 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.

[0044] 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 105. 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.

[0045] 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 any suitable sensors for operation of the drilling rig 102. In some embodiments, 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.

[0046] 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.

[0047] 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.

[0048] 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.

[0049] 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.

[0050] 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.

[0051] 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 real-time 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.

[0052] 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.

[0053] 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.

[0054] 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.

[0055] 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.

[0056] 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).

[0057] 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

[0058] 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).

[0059] As shown in Figures 3-34, the system and method disclosed herein provide another technique for slide drilling. During slide drilling, the surface weight on the drill bit ("WOB") may be varied periodically. This fluctuation may generate axial movement in the drill string, which helps to transfer the WOB based on the same principle as an agitator. The method disclosed herein, however, may be achieved without using another downhole tool (e.g., an

agitator). Thus, the WOB transfer may be achieved without an added pressure drop, making the system more robust, since any malfunction may be detected using equipment at the surface.

[0060] By applying a WOB variation at a predetermined frequency, the WOB transfer and the ROP may be increased. In some embodiments, this may be more effective than using an agitator. The WOB variation may not have an adverse effect on the motor toolface control. In some embodiments, the WOB variation may be combined with the agitator or an APG tool.

[0061] The WOB variation may be achieved with a drive system using an auto driller. It may also be achieved by equipment coupled to the drill string coming out of the drawworks or at the dead end of the drill string holding the hook load. In horizontal drilling embodiments, a small portion of the time may involve sliding to adjust the direction of drilling. Most of this time may be rotational drilling, which may be performed without an APG or agitator. This may reduce the amount of time that the APG or agitator is used as well as the energy to drive the APG or agitator. The system disclosed herein may be positioned at the surface, and it may be rotated on command (e.g., during sliding).

[0062] Figure 3 illustrates a schematic view of a vibration tool in a wellbore, according to an embodiment. The vibration tool is used in the drill string to generate axial excitation. The WOB may be varied at the top of the drill string. The drilling system may increase the efficiency of the WOB transfer, improve the rate of penetration ("ROP"), and increase the horizontal length that may be reached with the motor slide drilling.

[0063] Figure 4 illustrates a chart showing data related to an APG drill string configuration, according to an embodiment. The drill string configuration may have a shock sub installed adjacent to the APG. The baseline bottom hole assembly ("BHA") may be the same but without the APG tool.

[0064] Figures 5-8 illustrate graphs showing wellbore trajectories, according to an embodiment. In an example embodiment, the depth of the wellbore may be about 18000 feet.

[0065] Figures 9 illustrates a graph showing weight on bit ("WOB") oscillation, according to an embodiment. Figures 10 and 11 illustrate graphs showing simulation results of the rate of penetration ("ROP") with and without the WOB variation drilling system, respectively, according to an embodiment. Under the same surface, the WOB and ROP may be increased (e.g., doubled) when the system is activated with a 5000 pound WOB variation with multiple (e.g., 5) second cycles. In one example, the WOB may be 10,000 pounds, the downhole tool (e.g., the

motor) may be sliding, 250 gallons of fluid may be pumped through the drill string per minute, and the confining pressure in the wellbore may be 3000 PSI.

[0066] Figures 12 and 13 illustrate graphs showing the surface WOB with and without the WOB variation drilling system, respectively, according to an embodiment. The average surface WOB may be about 32,000 pounds for the embodiments of Figures 12 and 13.

[0067] Figures 14 and 15 illustrate graphs showing the downhole WOB with and without the WOB variation drilling system, respectively, according to an embodiment. The average surface WOB may be about 32,000 pounds for the embodiments of Figures 14 and 15. The downhole WOB may be higher with the WOB variation system, which means that the system improves the WOB transfer.

[0068] Figures 16 and 17 illustrate graphs showing the torque on the drill bit with and without the WOB variation drilling system, respectively, according to an embodiment. Due to higher downhole WOB, torque on the drill bit may be higher with the WOB variation system. The torque variation range may be similar for the embodiments in Figures 16 and 17.

[0069] Figure 18 illustrates a schematic view of the APG with a shock sub, according to an embodiment. Figure 19 illustrates a graph showing the rate of penetration ("ROP") with and without the WOB variation drilling system, according to an embodiment. Under the same surface WOB, ROP may be further improved using the APG with the shock sub.

[0070] Figures 20-22 illustrate graphs showing the surface WOB, downhole WOB, and downhole torque on the drill bit, respectively, according to an embodiment. The WOB variation system may be activated, and a vibration tool may be coupled to the drill string. The downhole WOB and bit torque may have a similar variation range compared with a baseline case without the WOB variation system and axial vibration tool.

[0071] Figures 23 and 24 illustrate graphs showing the frictional contact force in an axial direction without and with the WOB variation drilling system, respectively, according to an embodiment. The horizontal axis is the distance from the drill bit. As shown, the WOB variation system may reduce the average friction contact force (see the circles in Figure 23).

[0072] Figures 25-27 illustrate graphs showing a toolface history of the downhole tool without the WOB variation drilling system, with the WOB variation drilling system, and with the WOB variation drilling system and a vibration tool, respectively, according to an embodiment. The toolface for the embodiments in Figures 26 and 27 had more changes (e.g., the pipe had about 2

or 3 more wraps than in the baseline case of Figure 25) due to the increased torque on the drill bit. The macro level toolface change may be adjusted on the surface. There may be micro level toolface changes, especially for the embodiment shown in Figure 26. The toolface micro variation range may be within about 5 degrees, which may not have a large effect on the system directional performance.

[0073] Figure 28 illustrates a graph showing the toolface history of the downhole tool with the WOB variation drilling system, according to an embodiment. The toolface variation range may be about 5 degrees per WOB variation cycle. This may not have a large influence on the system directional performance.

[0074] Figure 29 illustrates a schematic view of an embodiment of the WOB variation drilling system, according to an embodiment. A hydraulic cylinder or other reciprocal mechanism may be attached to the deadline end, applying the WOB variation. In one example, the hookload may be about 97,000 pounds. If the pulley system has 10 lines, the tension on the deadline may be about 9,700 pounds. It may be manageable to create a tension load of 9,700 pounds with a 500 pound sinusoidal variation. The WOB variation drilling system may mechanically raise and lower the drill string and the downhole tool from the surface, which may reduce the friction between the drill string and the surrounding casing or wellbore wall.

[0075] In another embodiment, rather than raising and lowering the drill string and downhole tool mechanically at the surface, one or more pressure pulses may be transmitted downhole from the surface. The pressure pulses may be received by one or more vibration devices in the drill string or downhole tool. When the vibration devices receive the pressure pulses, the vibration devices may vibrate, thereby reducing the friction with the casing or wellbore wall.

[0076] In yet another embodiment, one or more electrical pulses may be transmitted downhole from the surface (e.g., through a wired drill string). The electrical pulses may be received by one or more electromechanical devices in the drill string or downhole tool. When the devices receive the electrical signals, the devices may vibrate, thereby reducing the friction with the casing or wellbore wall.

[0077] Figure 30 illustrates a graph showing the hookload with the WOB variation drilling system, according to an embodiment. The tension at the deadline or fast line may be about 1/10 of the hookload if the pulley system has 10 lines.

[0078] Figure 31 illustrates a graph showing the velocity of a drill pipe moving up and down at the surface due to action of the WOB variation drilling system, according to an embodiment. The maximum speed may be about 0.8 feet/second. If the deadline is attached to a powered moving end, the moving end may deliver a speed of about 8 feet/second when the pulley has 10 lines. Considering the dead line force of 9,700 pounds plus 500 pounds, the maximum power may be about 10,200 pounds * 8 feet/second. This equals about 81,600 ft-pounds/second, which equals about 148 horsepower. In comparison, if the standpipe pressure is 3,000 PSI, and the flow rate is 250 gallons/minute, the pump power may be $(3000 \text{ PSI} * 250 \text{ gallons/minute}) / 1714$. This equals about 438 horsepower.

[0079] Figure 32 illustrates a graph showing cyclic displacement of the drill pipe at the surface due to the action of the WOB variation drilling system, according to an embodiment. The drill pipe may move up and down about 1 foot every 5 seconds.

[0080] Figure 33 illustrates a graph showing the tensile stress in the drill pipe near the surface due to the action of the WOB variation drilling system, according to an embodiment. The stress variation amplitude created due to the WOB variation may be about 0.8 ksi. This may not have a large impact on drill pipe fatigue life.

[0081] In some embodiments, the methods of the present disclosure may be executed by a computing system. Figure 34 illustrates an example of such a computing system 3400, in accordance with some embodiments. The computing system 3400 may include a computer or computer system 3401A, which may be an individual computer system 3401A or an arrangement of distributed computer systems. The computer system 3401A includes one or more analysis modules 3402 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 3402 executes independently, or in coordination with, one or more processors 3404, which is (or are) connected to one or more storage media 3406. The processor(s) 3404 is (or are) also connected to a network interface 3407 to allow the computer system 3401A to communicate over a data network 3409 with one or more additional computer systems and/or computing systems, such as 3401B, 3401C, and/or 3401D (note that computer systems 3401B, 3401C and/or 3401D may or may not share the same architecture as computer system 3401A, and may be located in different physical locations, e.g., computer systems 3401A and 3401B may be located in a processing facility, while in communication with one or more computer systems such as 3401C

and/or 3401D that are located in one or more data centers, and/or located in varying countries on different continents).

[0082] A processor may include a microprocessor, microcontroller, processor module or subsystem, programmable integrated circuit, programmable gate array, or another control or computing device.

[0083] The storage media 3406 may be implemented as one or more computer-readable or machine-readable storage media. Note that while in the example embodiment of Figure 34 storage media 3406 is depicted as within computer system 3401A, in some embodiments, storage media 3406 may be distributed within and/or across multiple internal and/or external enclosures of computing system 3401A and/or additional computing systems. Storage media 3406 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), BLUERAY® 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.

[0084] In some embodiments, the computing system 3400 contains one or more rig control module(s) 3408. In the example of computing system 3400, computer system 3401A includes the rig control module 3408. 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.

[0085] It should be appreciated that computing system 3400 is only one example of a computing system, and that computing system 3400 may have more or fewer components than shown, may combine additional components not depicted in the example embodiment of Figure 34, and/or computing system 3400 may have a different configuration or arrangement of the components depicted in Figure 34. The various components shown in Figure 34 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.

[0086] 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.

[0087] 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.

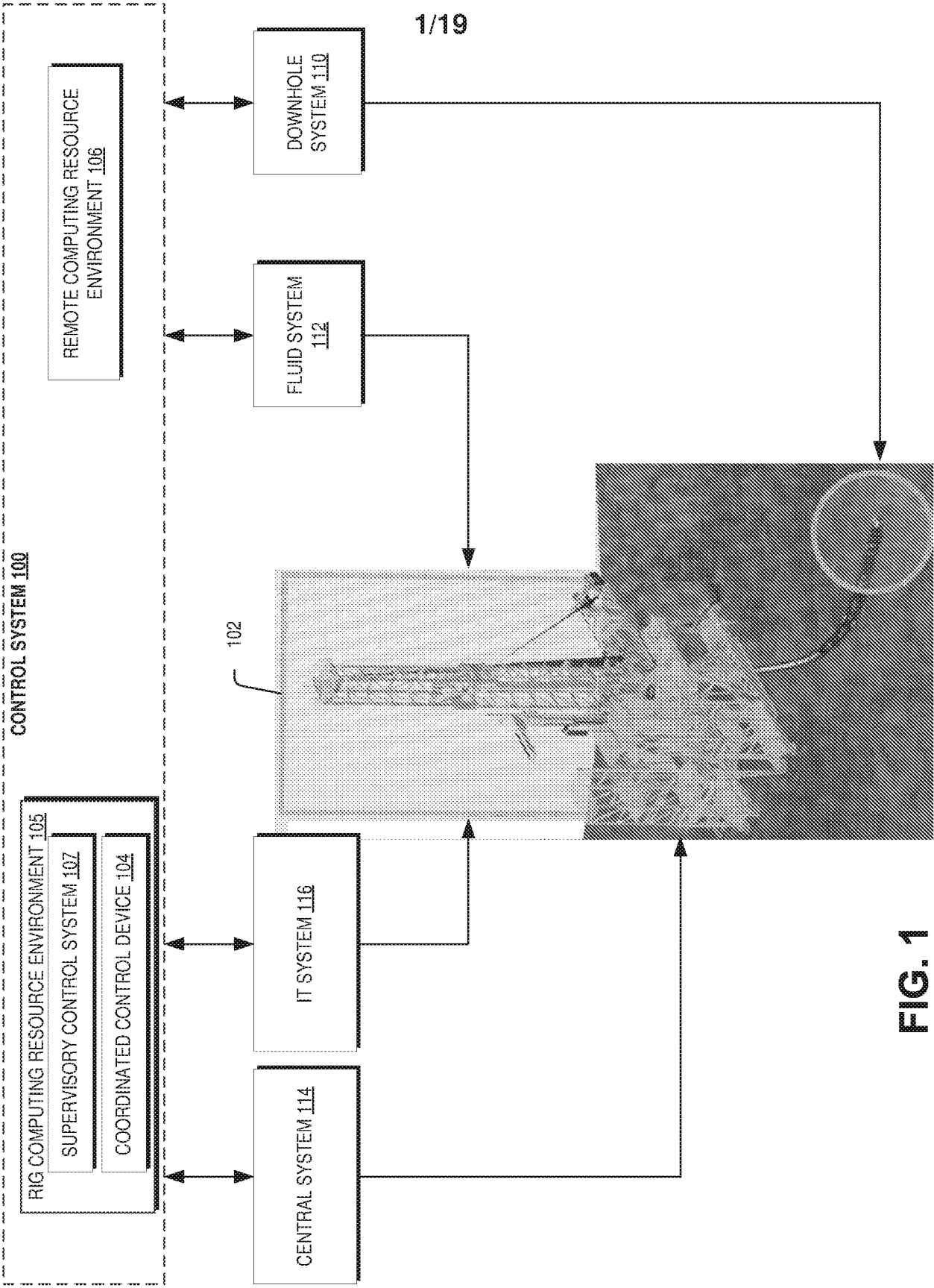
CLAIMS

What is claimed is:

1. A method for varying a weight on a drill bit in a wellbore, comprising:
running a downhole tool into the wellbore on a drill string, wherein the downhole tool comprises a motor and a drill bit;
rotating the drill bit with the motor to drill the wellbore in a subsurface formation; and
varying an axial force applied to the drill string from a surface location.
2. The method of claim 1, further comprising causing the drill string to vibrate with a vibration tool coupled to the drill string.
3. The method of claim 1, wherein varying the axial force comprises increasing and decreasing the axial force in a substantially sinusoidal manner.
4. The method of claim 1, wherein the axial force is varied mechanically.
5. A method for varying a weight on a drill bit in a wellbore, comprising:
running a downhole tool into the wellbore on a drill string, wherein the downhole tool comprises a motor, a drill bit, and a vibration device;
rotating the drill bit with the motor to drill a deviated or horizontal portion of the wellbore in a subsurface formation;
causing the downhole tool to vibrate using the vibration device as the drill bit rotates; and
varying an axial force applied to the drill string from a surface location.
6. The method of claim 5, wherein varying the axial force comprises increasing and decreasing the axial force in a substantially sinusoidal manner.
7. The method of claim 5, wherein the axial force is varied as the drill bit rotates.
8. The method of claim 5, wherein the axial force is varied when the drill bit is not rotating.

9. A system for varying a weight on a drill bit in a wellbore, comprising:
a pulley system comprising a crown block having first and second lines wrapped at least partially thereabout; and
a hook coupled to the pulley system, wherein the hook is configured to support a drill string that extends into a wellbore, and wherein the pulley system varies an axial force applied to the drill string as the drill string moves within the wellbore.
10. The system of claim 9, wherein the pulley system increases and decreases the axial force in a substantially sinusoidal manner.
11. The system of claim 9, further comprising a vibration tool coupled to the drill string, wherein the vibration tool is configured to vibrate as the axial force applied to the drill string varies.
12. The system of claim 9, wherein the pulley system varies the axial force when the first line is pulled.
13. A system for varying a weight on a drill bit in a wellbore, comprising:
a device located on or above a surface; and
a drill string extending into the wellbore from the surface, wherein the drill bit is coupled to the drill string, and wherein the device is configured to generate a pressure pulse and send the pressure pulse into the wellbore to cause the drillstring to vibrate, thereby reducing friction as the drill string slides within the wellbore.
14. The system of claim 13, further comprising a vibration tool coupled to the drill string, wherein the vibration tool causes the drill string to vibrate in response to receiving the pressure pulse.
15. The system of claim 13, wherein the drill string vibrates while the drill bit is rotating.

16. The system of claim 13, wherein the drill string vibrates when the drill bit is not rotating.
17. A system for varying a weight on a drill bit in a wellbore, comprising:
 - a device located on or above a surface; and
 - a drill string extending into the wellbore from the surface, wherein the drill bit is coupled to the drill string, and wherein the device is configured to generate an electrical pulse and send the electrical pulse into the wellbore to cause drillstring to vibrate, thereby reducing friction as the drill string slides within the wellbore.
18. The system of claim 17, further comprising a vibration tool coupled to the drill string, wherein the vibration tool causes the drill string to vibrate in response to receiving the electrical pulse.
19. A method for drilling a wellbore, comprising:
 - running a drill string into a wellbore, wherein a drill bit is coupled to the drill string;
 - vibrating the drillstring as the drill string slides within the wellbore; and
 - halting vibration of the drillstring as the drill bit engages in rotational drilling.
20. The method of claim 19, wherein the drill string is vibrated by increasing and decreasing the force applied to the drill string from a surface location.



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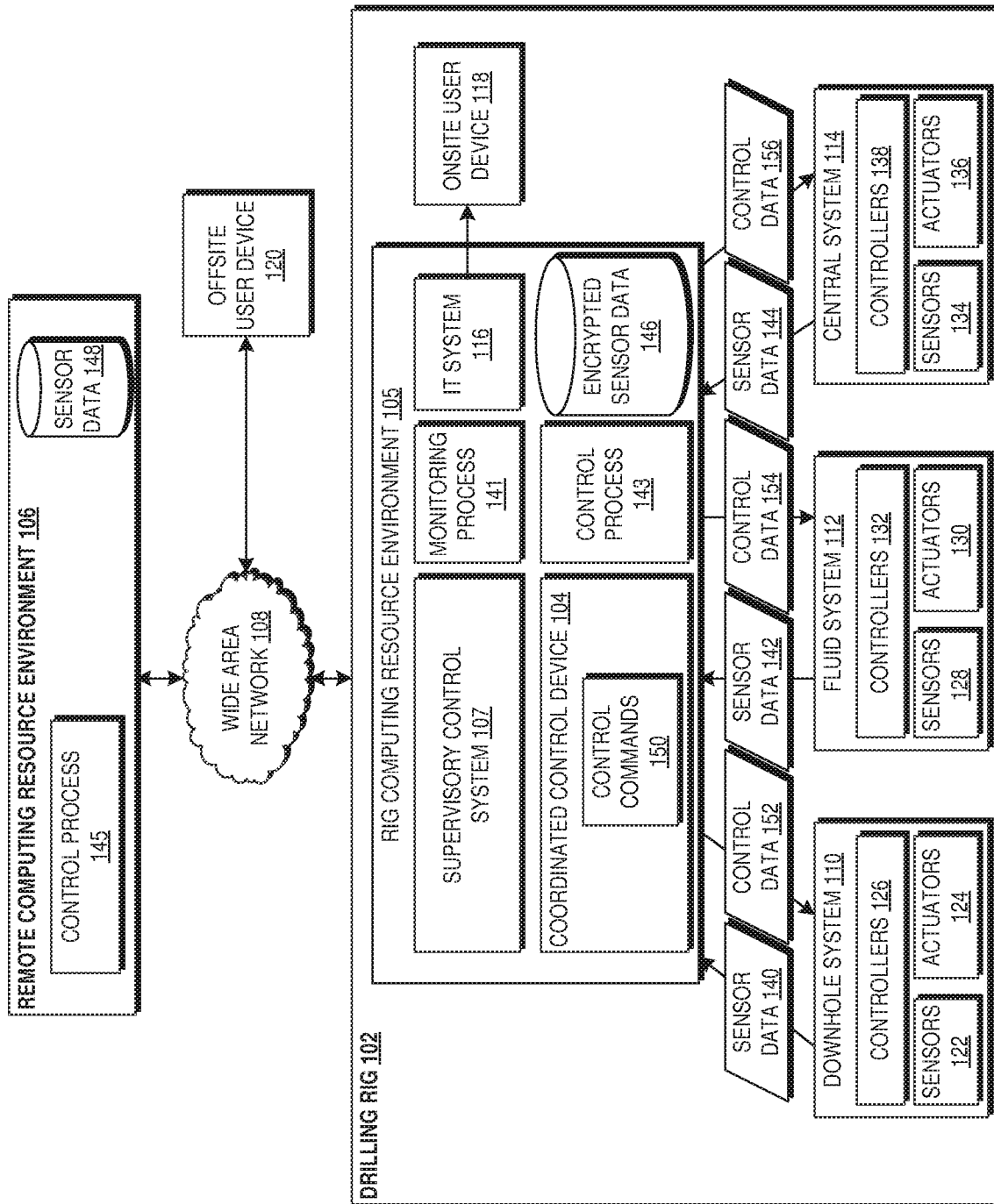


FIG. 2

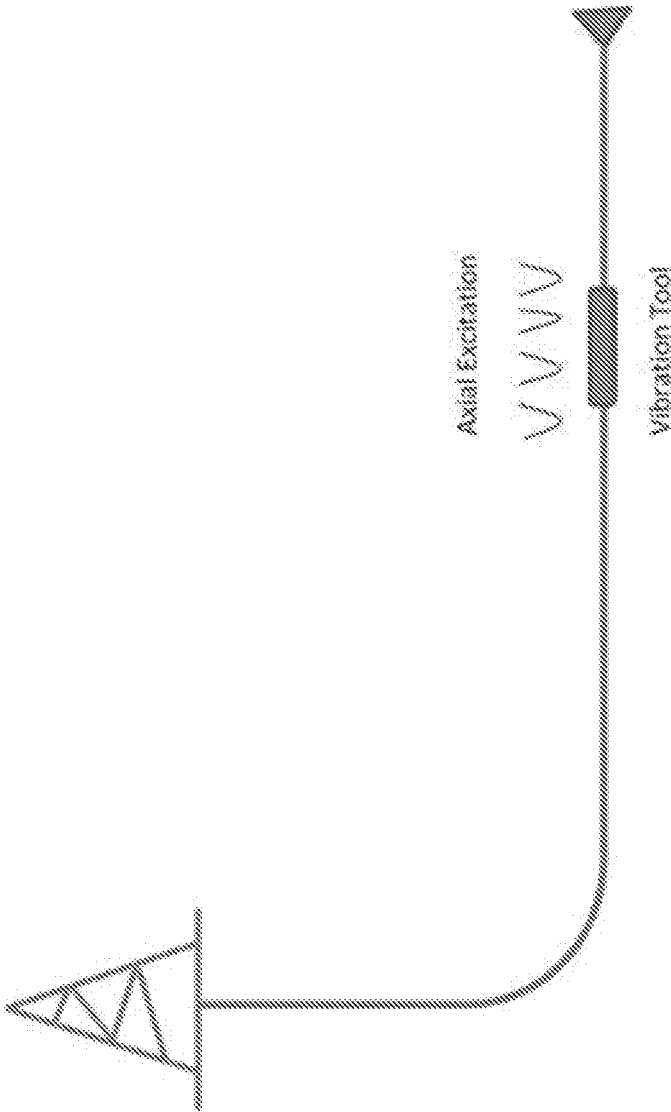
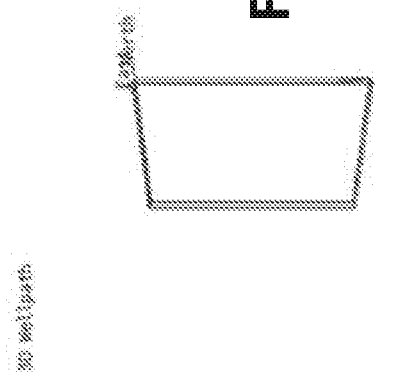
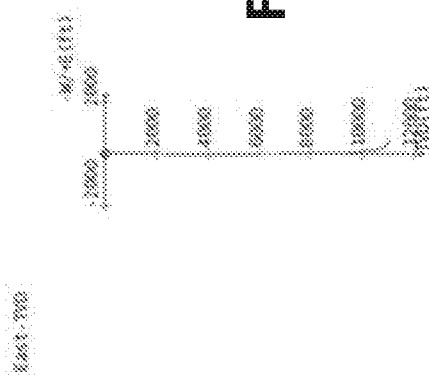
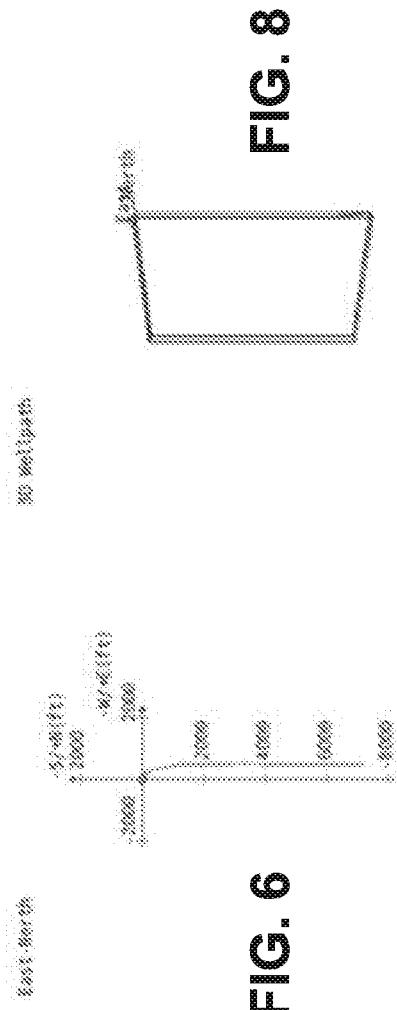
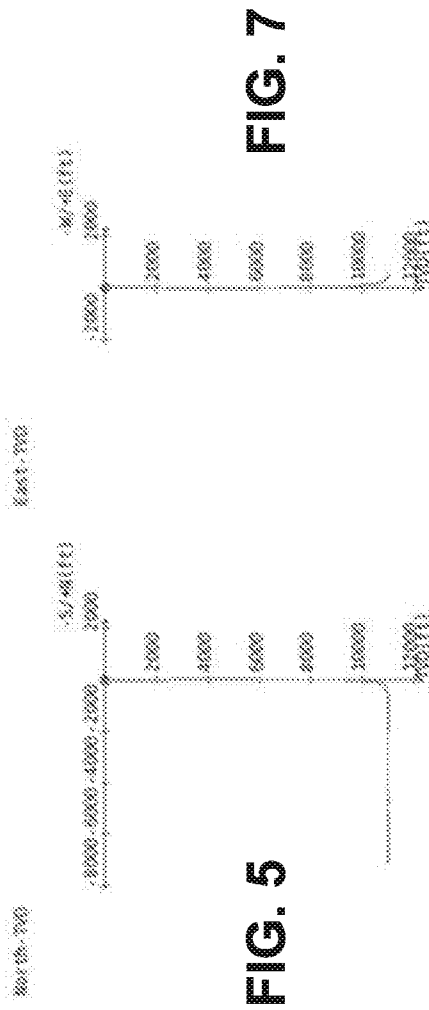


FIG. 3

Type	QD (in)	TD (in)	Length (ft)	Acce. (ft/s ²)	MC	Acco. (g)	Weight	Acce. (ft/s ²)
Pipe/Tool Joint	4.8750	3.3400	13357.066	17258.000	2276	3045	14.980 lba/ft	254914
80%	5.0000	3.4850	30.500	45600.934	0	819	1016.979 lba	67925
Pipe/Tool Joint	4.8750	3.3400	4273.000	4430.434	713	811	14.200 lba/ft	66098
90% Pipe/Tool Joint	4.8750	2.5625	91.000	107.434	33	100	30.930 lba/ft	7076
Pipe/Collar	4.8750	2.6875	3.670	105.544	3	87	0.2836 lba/in3	4327
Pipe/Collar	4.7500	2.6875	30.670	102.874	35	86	0.2836 lba/in3	4200
Stabilizer	5.7500	2.7500	5.460	72.304	5	71	0.2836 lba/in3	2858
Pipe/Collar	4.7500	2.6875	30.770	66.744	13	66	0.2836 lba/in3	2798
90% Pipe/Collar	4.5625	2.6875	2.900	35.974	2	53	0.2836 lba/in3	1443
Stabilizer	5.7500	2.7500	5.430	32.994	5	51	0.2836 lba/in3	1394
SLB P208	5.7500	0.0000	36.814	27.954	45	46	1005.370 lba	3663
211	51.000	61.000	87.02	63.52	1	1	33.02 lba	12

FIG. 4



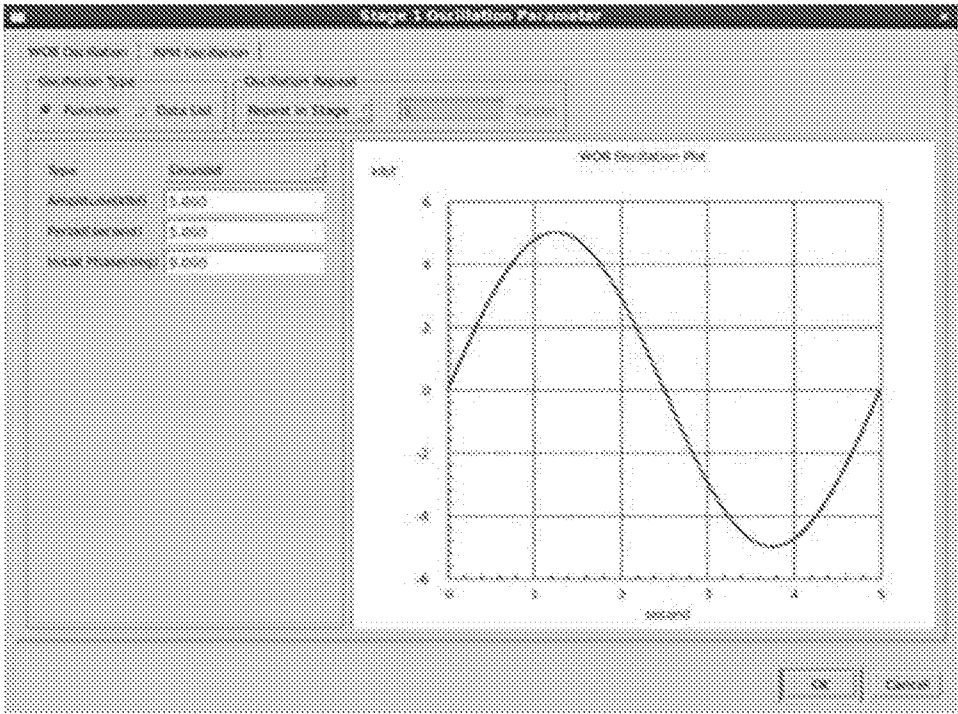


FIG. 9

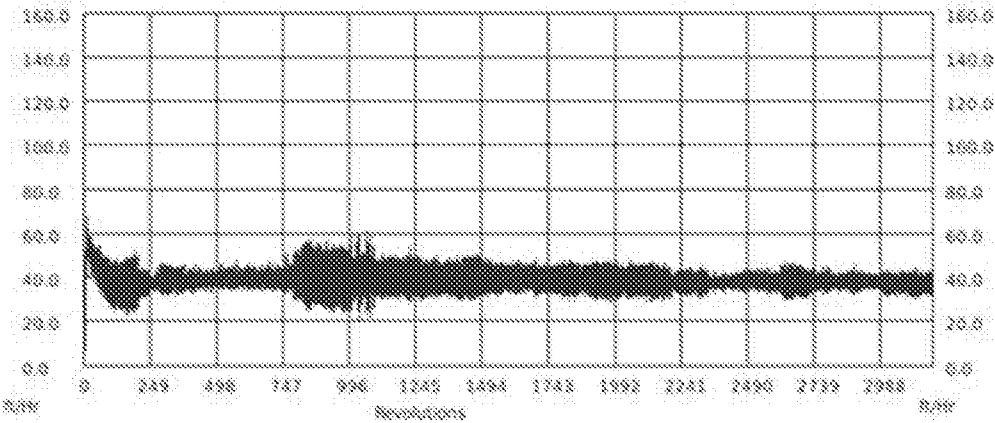


FIG. 10

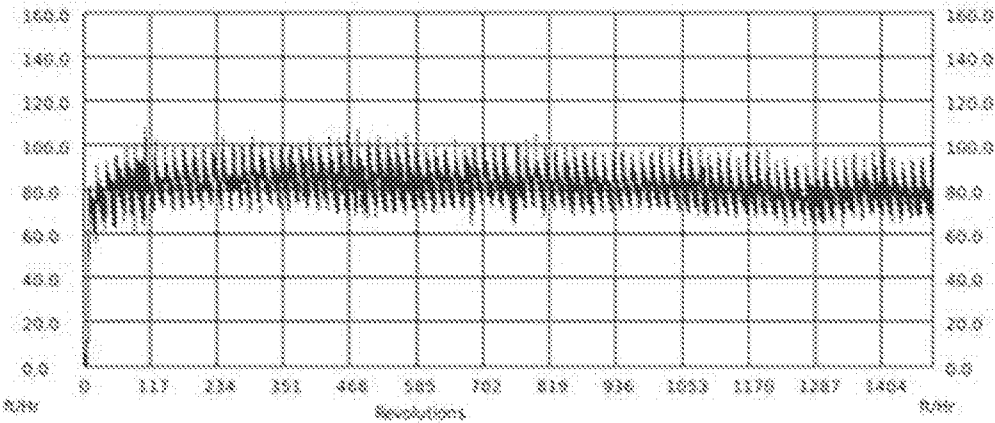


FIG. 11

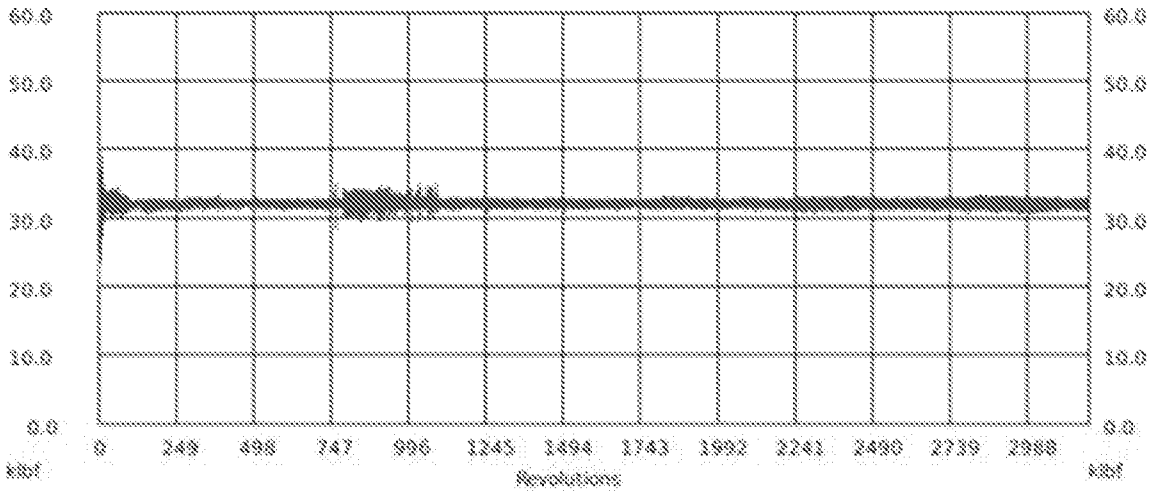


FIG. 12

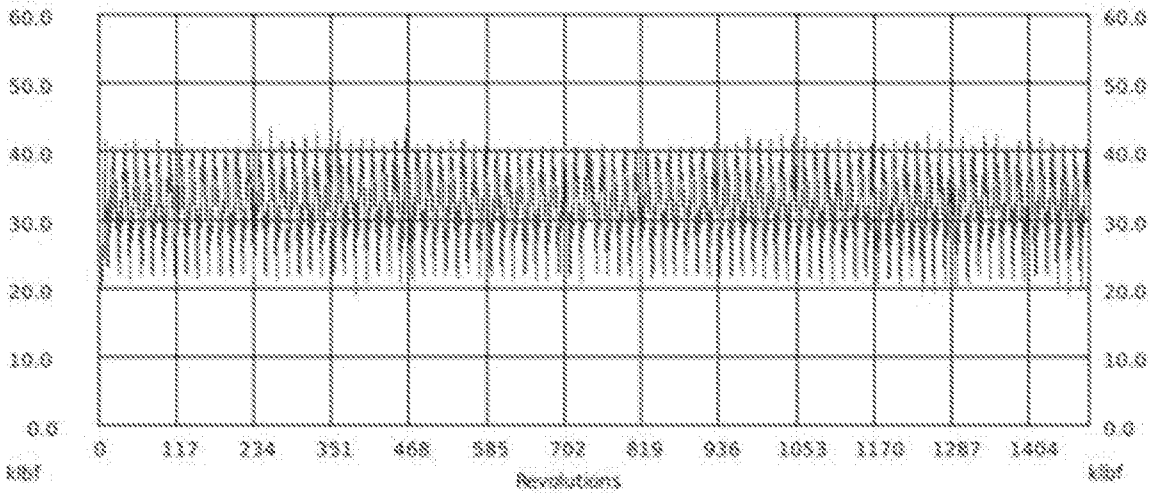
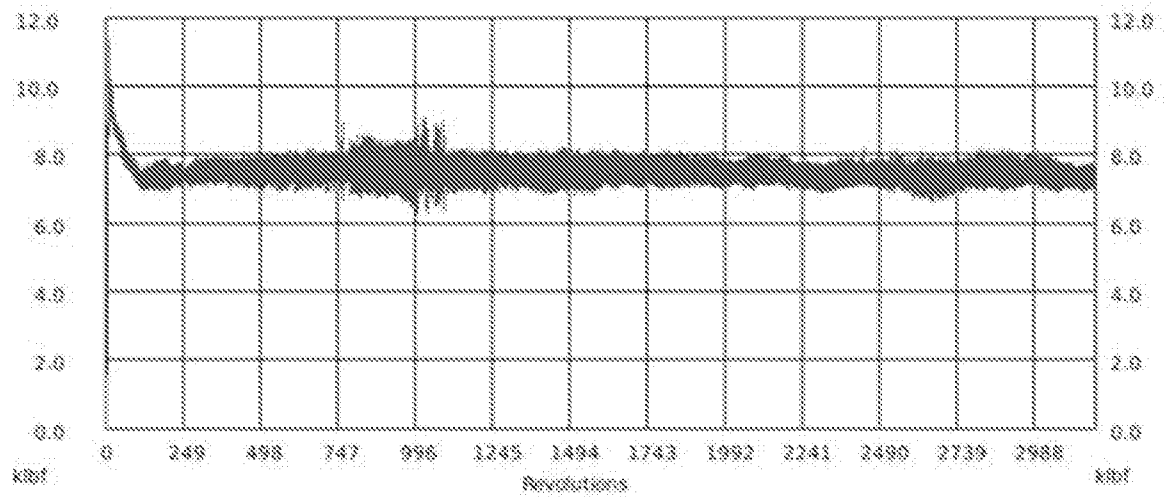
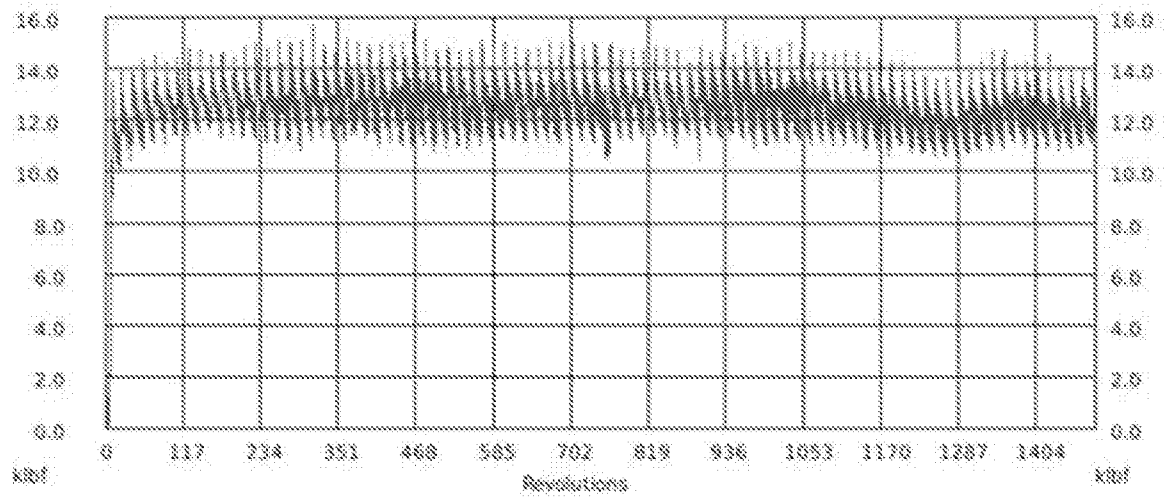


FIG. 13

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**FIG. 14****FIG. 15**

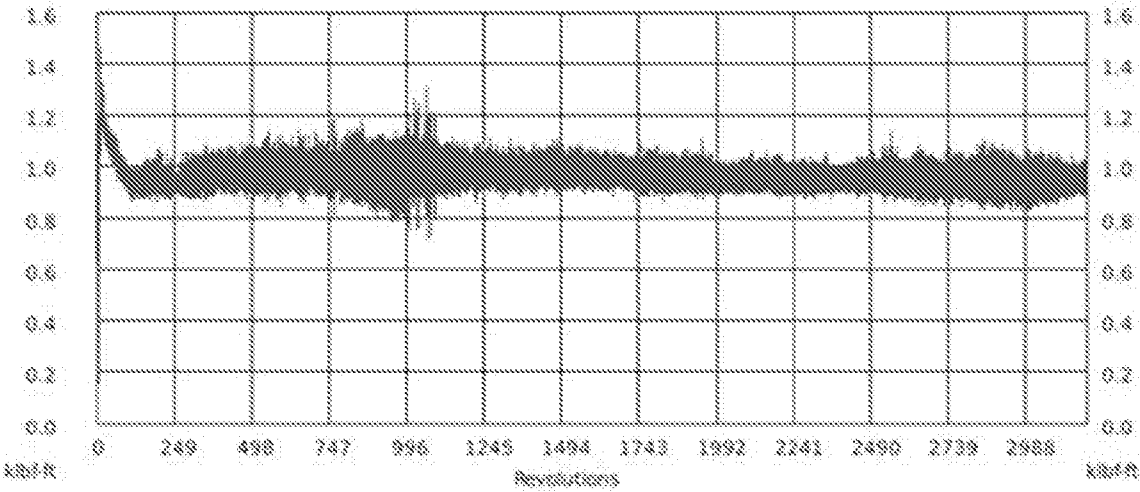


FIG. 16

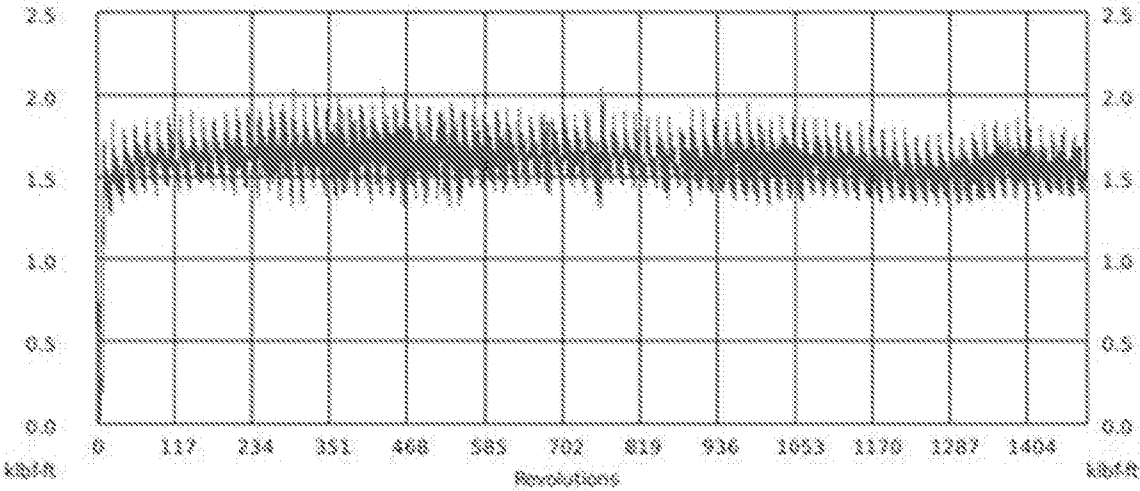


FIG. 17

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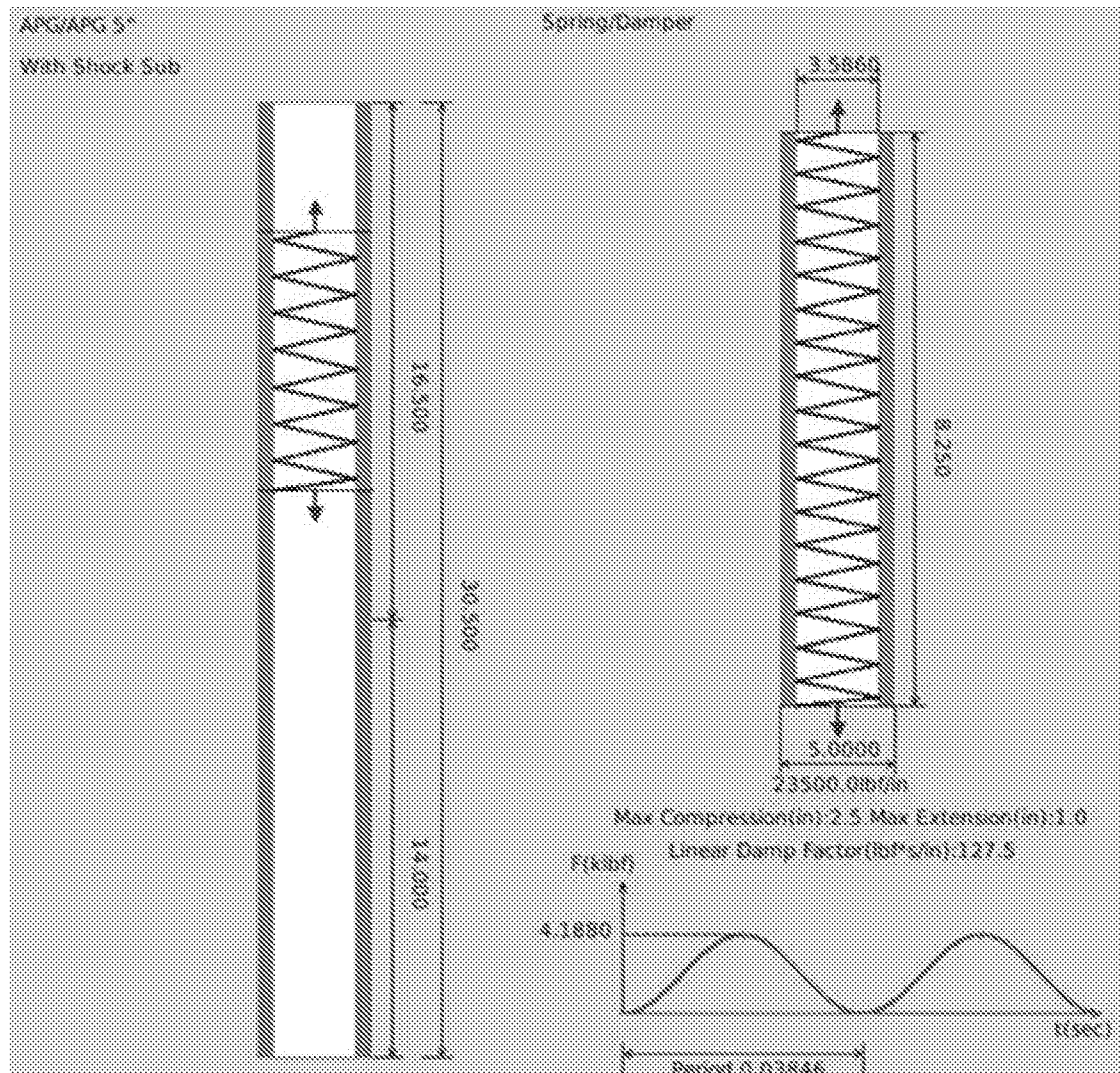


FIG. 18

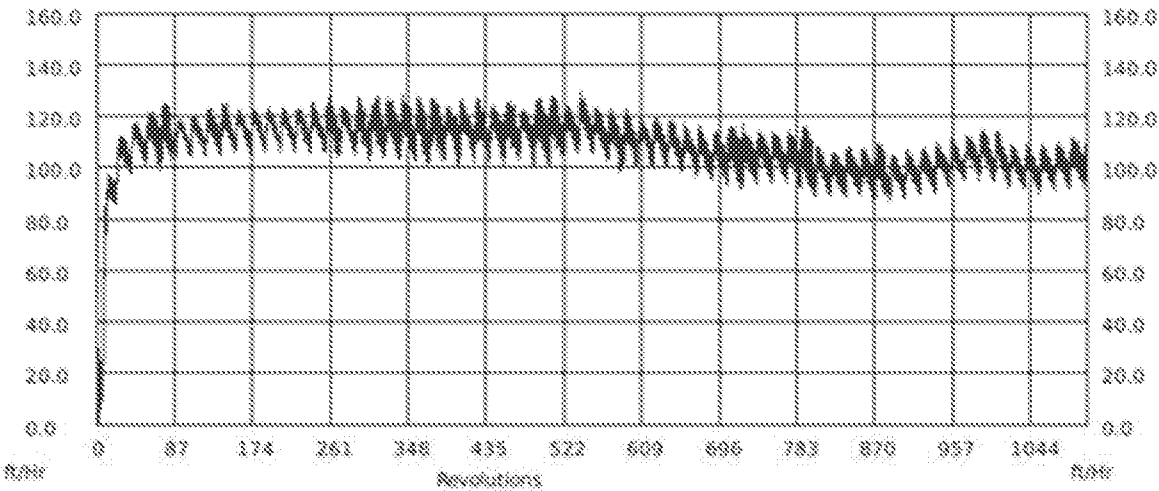


FIG. 19

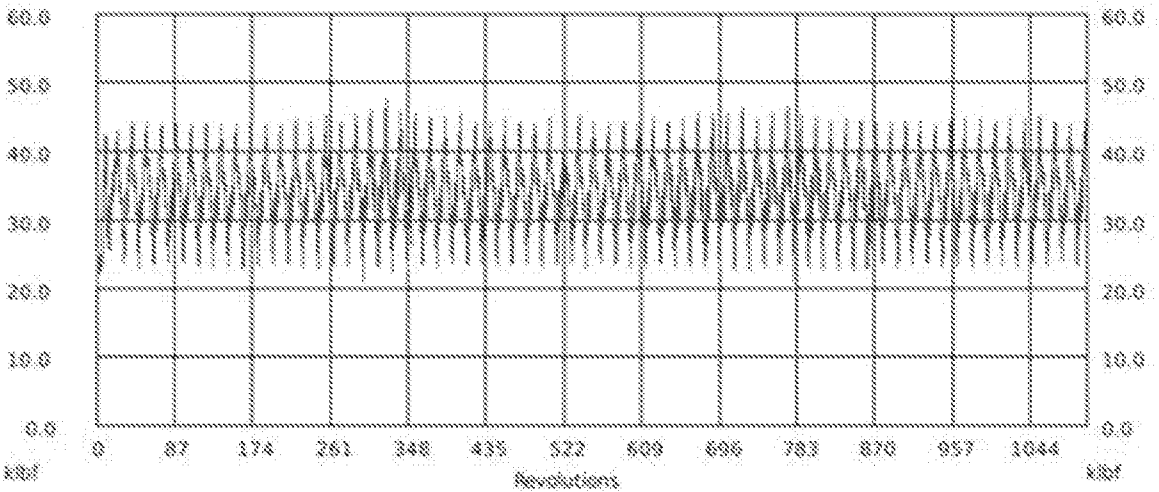


FIG. 20

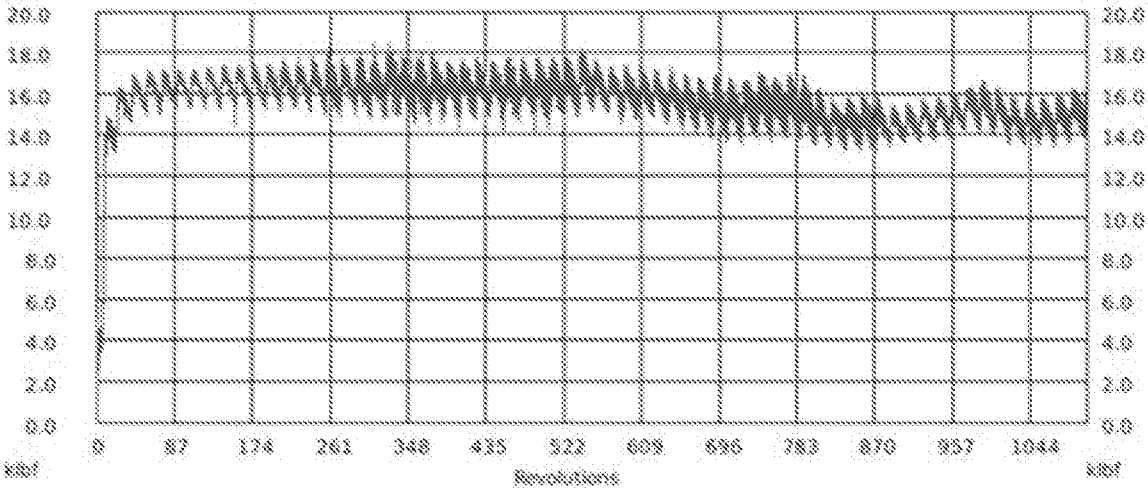


FIG. 21

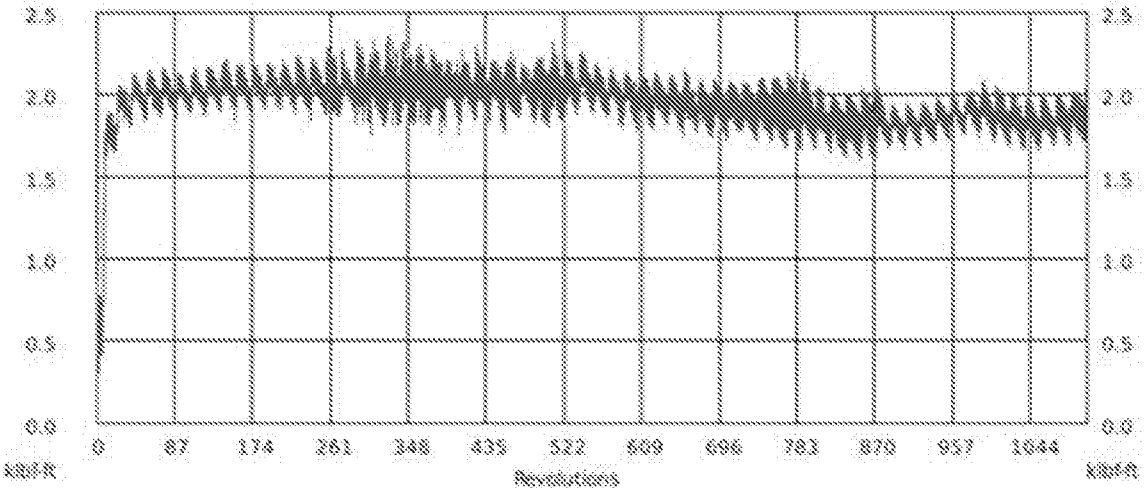


FIG. 22

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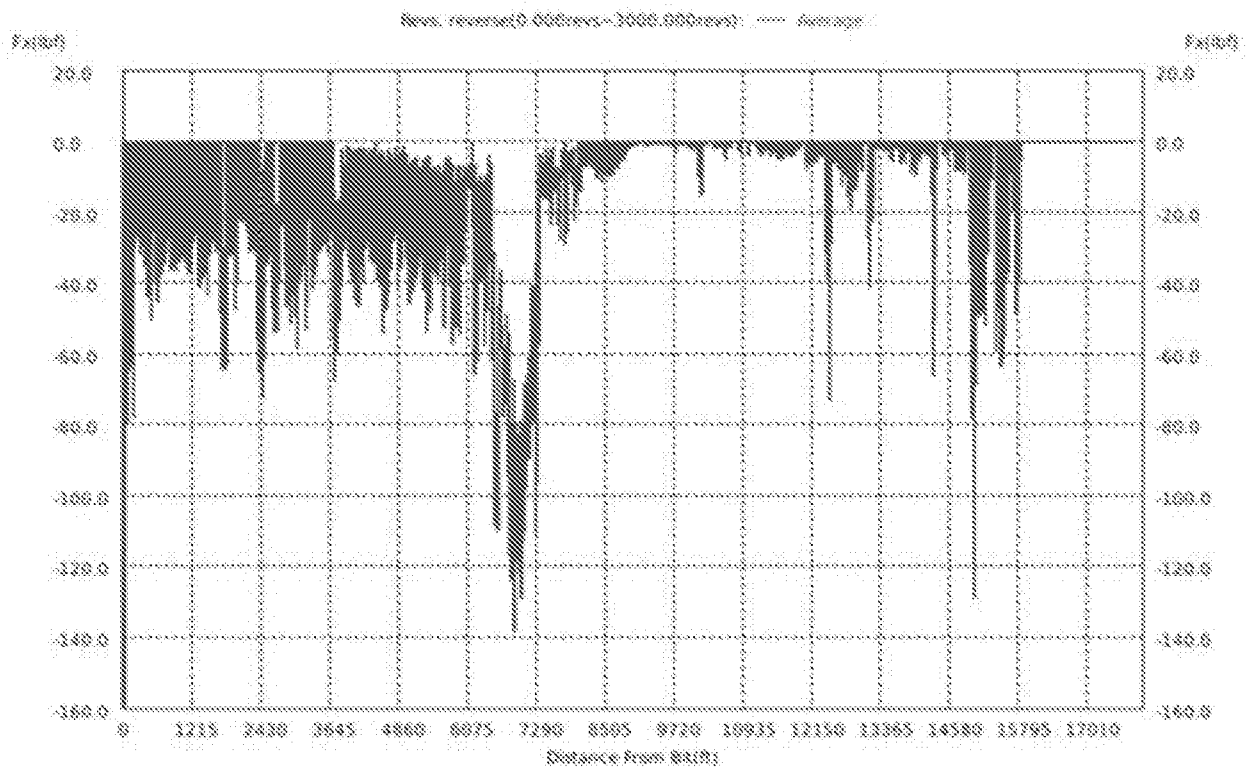


FIG. 23

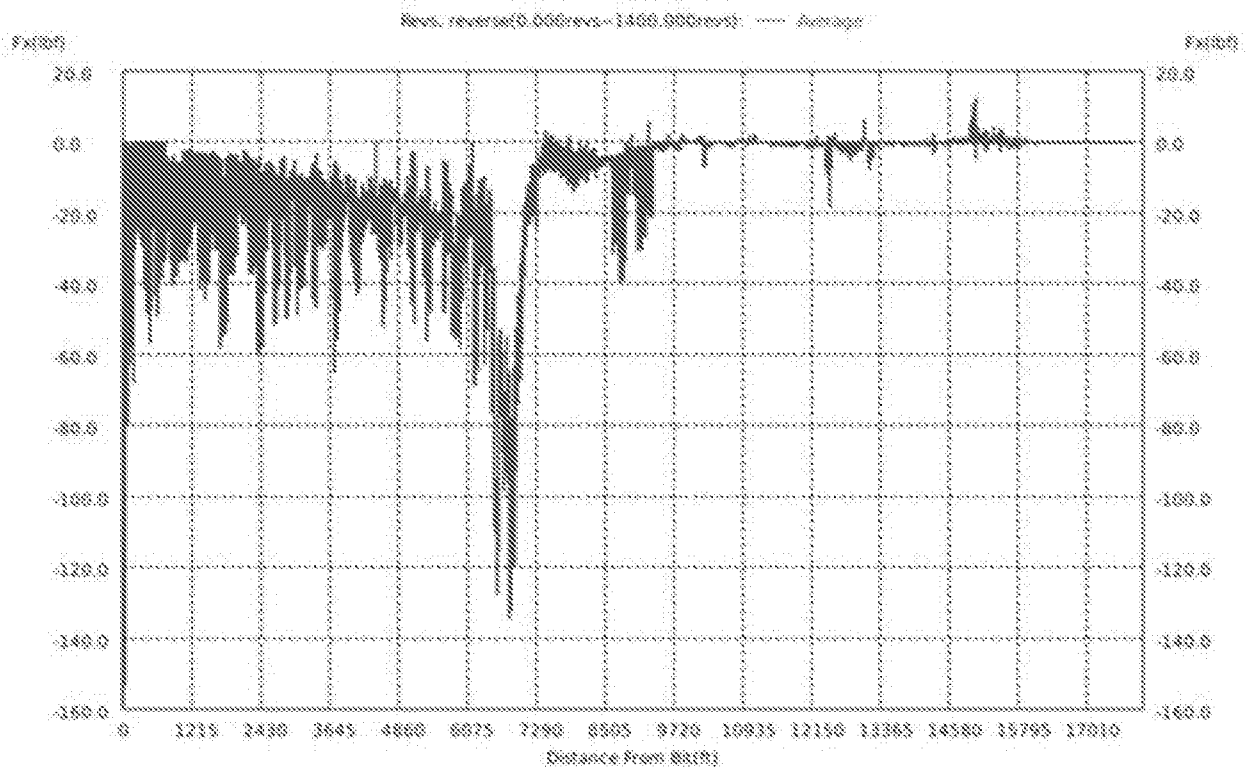
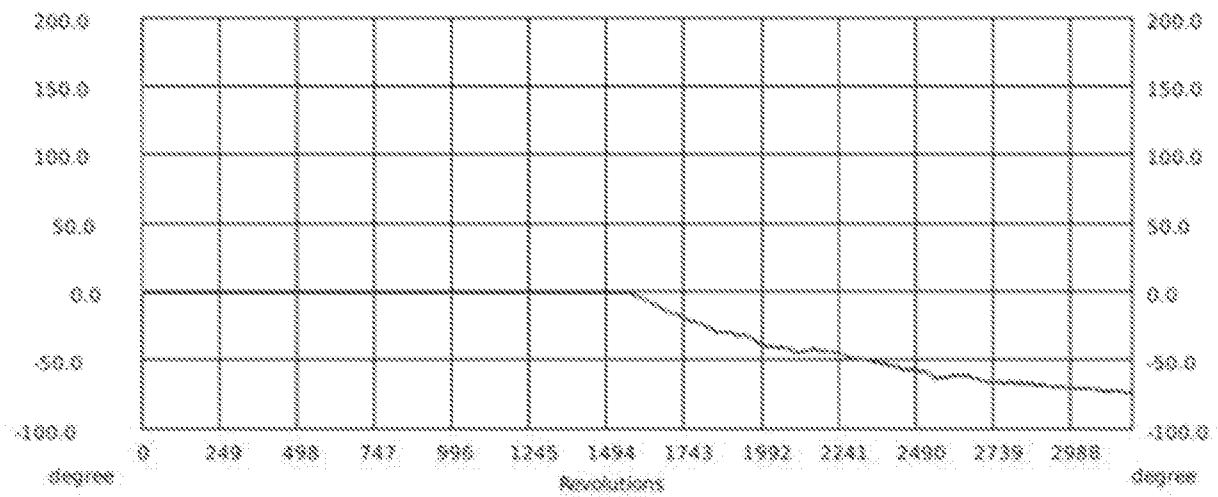
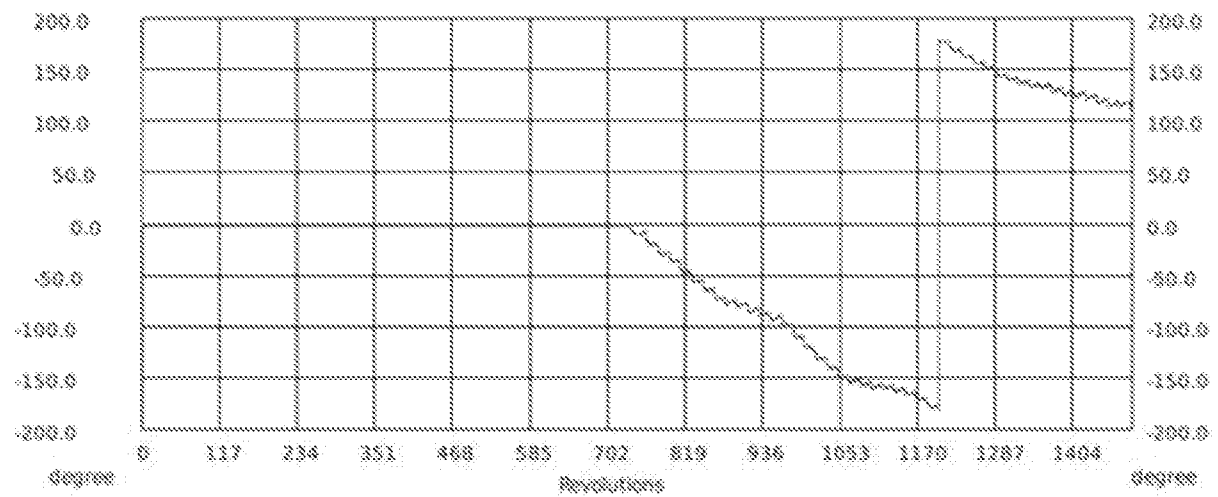


FIG. 24

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**FIG. 25****FIG. 26**

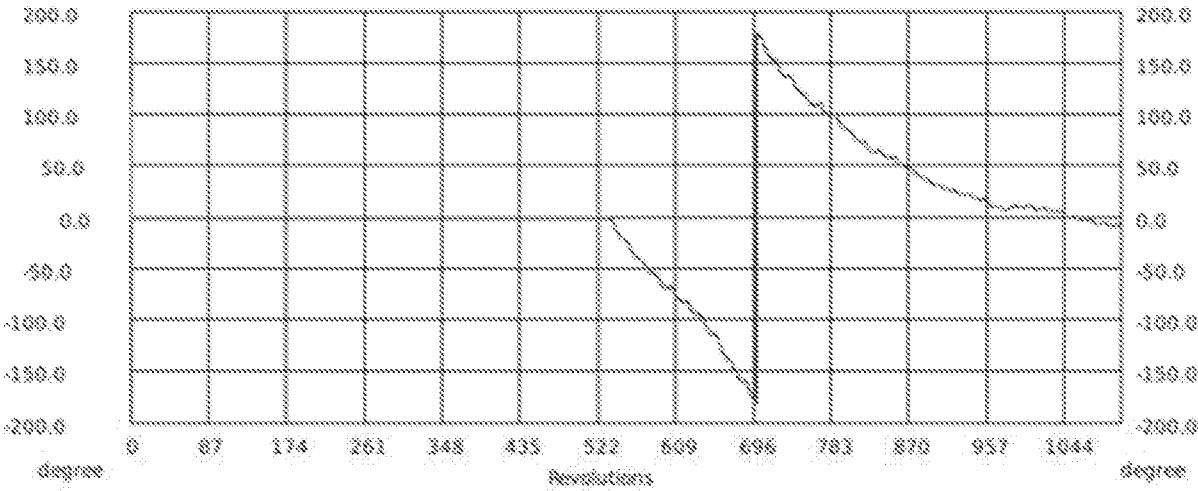
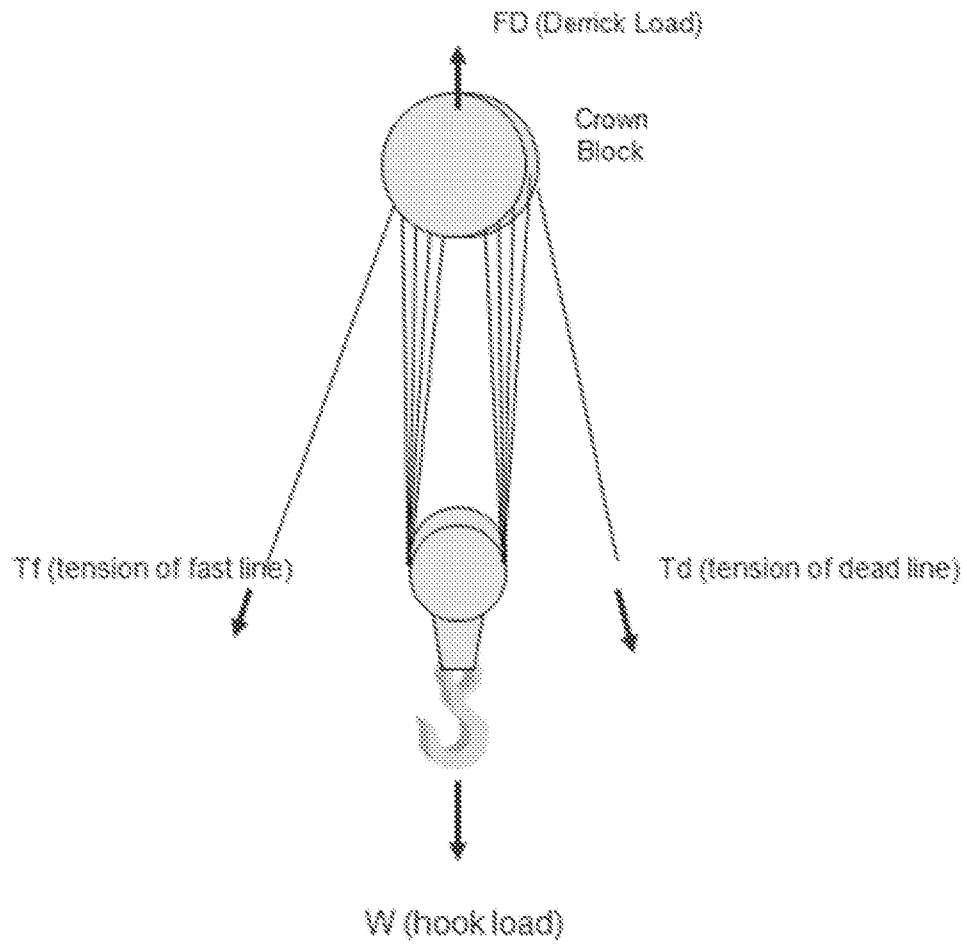


FIG. 27



FIG. 28

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FIG. 29

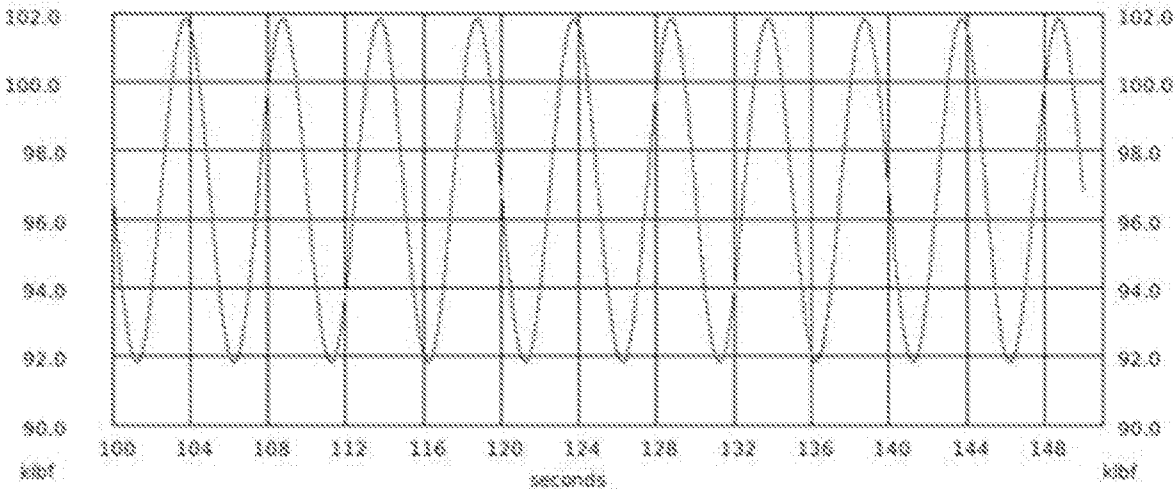


FIG. 30

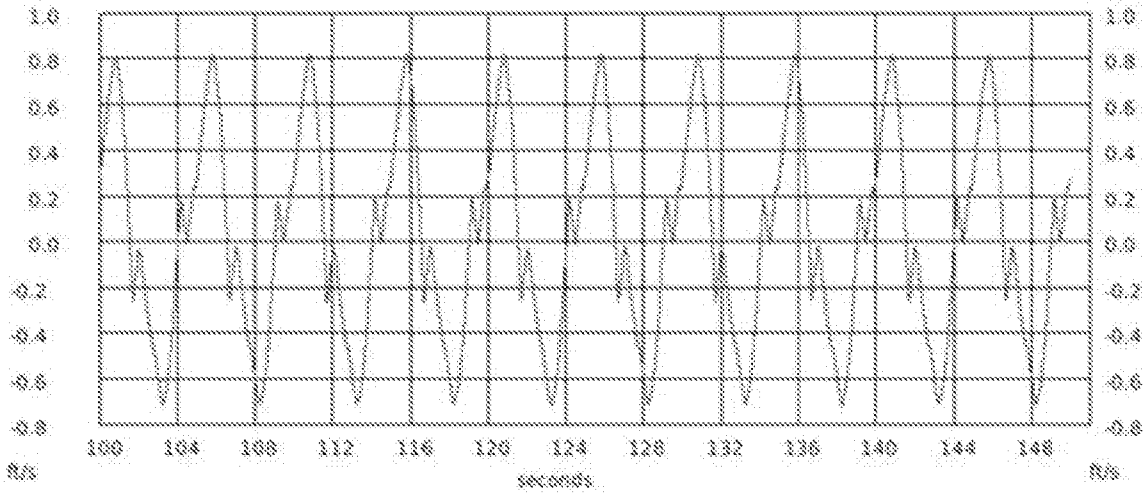


FIG. 31

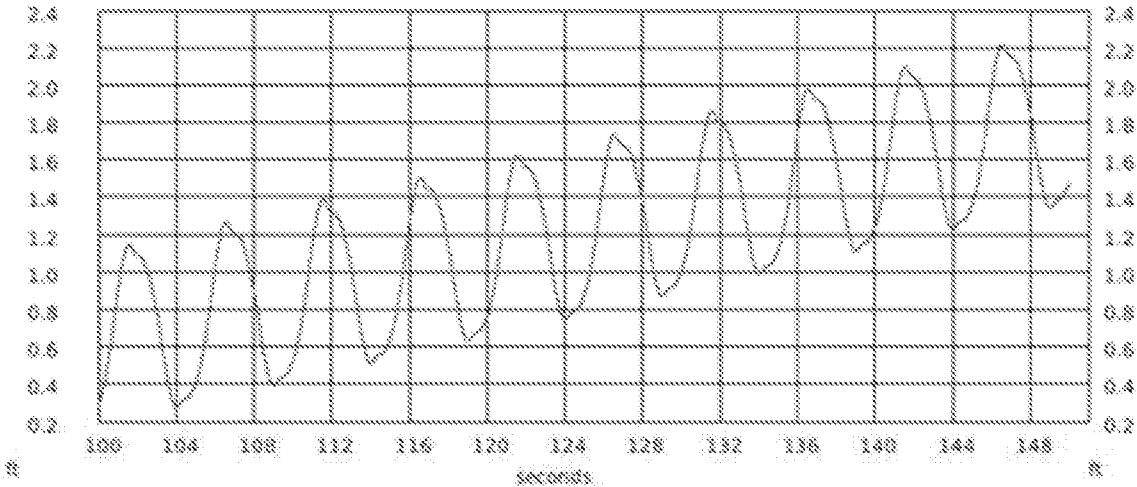


FIG. 32

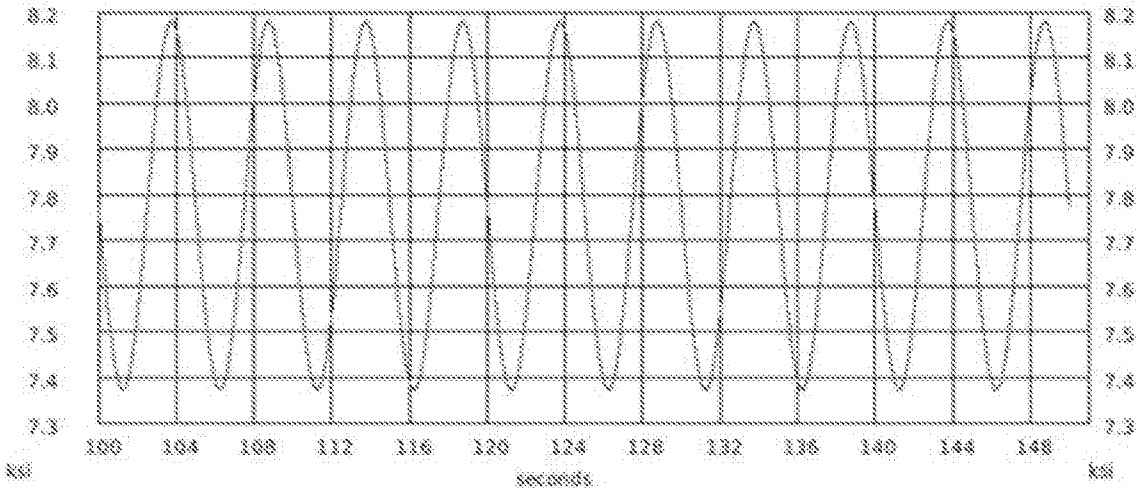
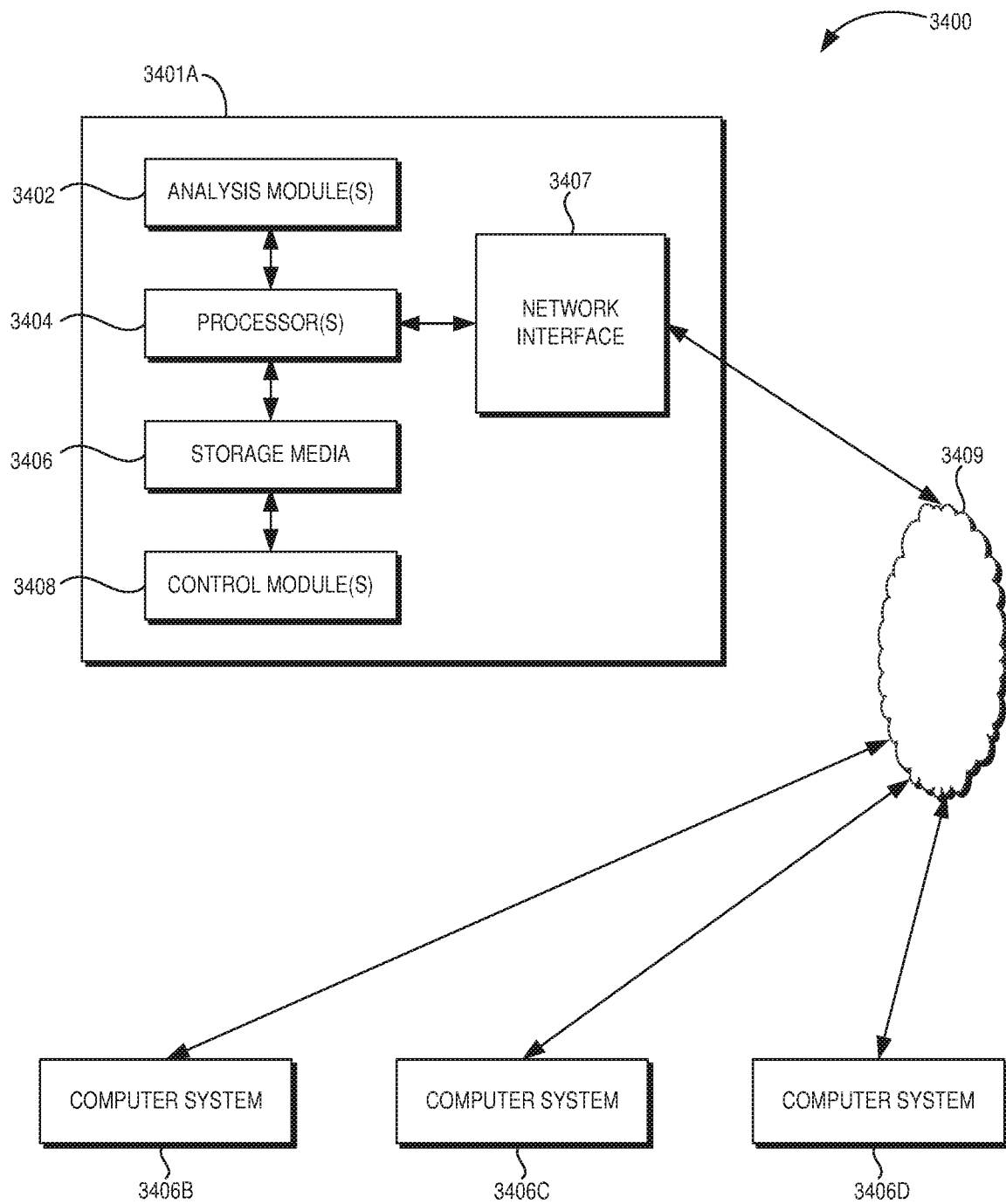


FIG. 33

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**FIG. 34**

INTERNATIONAL SEARCH REPORT

International application No.

PCT/CN2015/080911

A. CLASSIFICATION OF SUBJECT MATTER

E21B 7/24(2006.01)i; E21B 1/02(2006.01)i; E21B 6/00(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)

E21B7/-;E21B1/-;E21B6/-;E21B44/-;E21B28/-;E21B3/-.

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

CNPAT, WPI, EPODOC, CNKI:WOB,weight,bit,drill+,var+,wellbore,force,axial,oscilat+,vibra+,pulley.

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	WO 2015051027 A1 (HARELAND, GEIR) 09 April 2015 (2015-04-09) page 7 line 20-page 8 line 3, figure 1	1-12
Y	US 2010139912 A1 (PFAHLERT, ROGER ET AL.) 10 June 2010 (2010-06-10) paragraphs [0213], [0219], [0231], figures 1-8	1-8
Y	US 5310014 A (MUELLER, HARLAN F.) 10 May 1994 (1994-05-10) column 5 line 3-column 11 line 23, figures 1-4	9-12
X	US 2005236190 A1 (LEWAL DRILLING LTD.) 27 October 2005 (2005-10-27) paragraph [0078], figure 6	13-18
X	US 6796390 B1 (SHELL OIL CO.) 28 September 2004 (2004-09-28) column 6 lines 3-11, figures 1-5	19-20
A	US 5540295 A (SERRETTE, BILLY J.) 30 July 1996 (1996-07-30) the whole document	1-20

☐ Further documents are listed in the continuation of Box C.☒ See patent family annex.

* Special categories of cited documents:

“A” document defining the general state of the art which is not considered to be of particular relevance

“E” earlier application or patent but published on or after the international filing date

“L” document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

“O” document referring to an oral disclosure, use, exhibition or other means

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