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## Methods and apparatus for optimizing downhole drilling conditions using a smart downhole system

### Abstract

An apparatus and method of drilling a wellbore using a drill string, one or more controllers, and one or more sensors. The method includes drilling the wellbore using the drill string; and measuring, by the sensor(s), a parameter. The method also includes, using the controller(s) to: calculate an efficiency parameter based on the measured parameter; calculate a difference between the calculated efficiency parameter and a target efficiency parameter; and generate instructions to reduce the difference. The method also includes implementing, by a controller, instructions to reduce the difference between the measured efficiency parameter and the target efficiency parameter.

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## Background/Summary

CROSS-REFERENCE TO RELATED APPLICATION (1) This application is a continuation of U.S. patent application Ser. No. 17/554,176, filed Dec. 17, 2021, the entire disclosure of which is hereby incorporated herein by reference.

BACKGROUND

(1) At the outset of a drilling operation, drillers typically establish a drilling plan that includes a target location and a drilling path, or well plan, to the target location. Once drilling commences, the bottom hole assembly ("BHA") is directed or "steered" from a vertical drilling path in any number of directions, to follow the proposed well plan. For example, to recover an underground hydrocarbon deposit, a well plan might include a vertical section to a point above the reservoir, then a directional section and deviated or horizontal section that penetrates the deposit. The drilling operator may then steer the BHA, including the bit, through the vertical, directional, and horizontal aspects in accordance with the plan.

(2) Conventionally, when a drilling operator provides instructions to the BHA and other drilling equipment, the drilling operator uses his or her past experiences and—in least in part—estimated downhole conditions to create drilling instructions. The conditions are estimated because not all parameters measured and/or calculated downhole are relayed to the surface in a timely manner. Instead, some downhole measurements are only accessible at the surface of the well when the downhole tool is brought to the surface and the measurements are then downloaded from the tool.

When this is the case, these downhole conditions or measurements are estimated based on their relationship with more readily available measurements. Examples of estimated measurements include an estimated weight on the bit ("WOB"), an estimated torque on bit, and an estimated differential pressure. These estimated measurements, however, are not always correct. For example, the estimated WOB calculated at the surface may be incorrect due to higher-than-expected friction between the drill string and the wellbore, which results in a lower actual WOB. The use of incorrect estimated measurements in combination with the drilling operator's subjective response to the incorrect estimated measurement can lead to less-than-optimal drilling instructions and conditions. As a result, unplanned drilling events such as excessive vibration, bit whirl, and bit balling may occur.

SUMMARY

(3) In some embodiments, the present disclosure includes a method of drilling a wellbore using a drill string and a smart downhole system that includes one or more downhole controllers and one or more downhole sensors, the method including: (a) storing, in the one or more downhole controllers, a target efficiency parameter; (b) drilling the wellbore using the drill string; (c) measuring, by one or more downhole sensors, a parameter; (d) calculating, by the one or more downhole controllers, an efficiency parameter based on the measured parameter; (c) calculating, by the one or more downhole controllers, a difference between the calculated efficiency parameter and the target efficiency parameter; (f) generating, by the one or more downhole controllers, first instructions to reduce the difference; (g) sending, from the one or more downhole controllers and to a surface controller, the first instructions; (h) generating, by the surface controller, second instructions based on the first instructions; and (i) implementing, by the surface controller, the second instructions to reduce the difference between the measured efficiency parameter and the target efficiency parameter. In some embodiments, the target efficiency parameter is minimum downhole vibration; and wherein the step (d) calculates downhole vibration. In some embodiments, the difference exceeding a threshold indicates that the calculated downhole vibration should be reduced; wherein the first instructions are associated with minimizing the downhole vibration; and wherein the second instructions reduce a feedoff rate to minimize the downhole vibration. In some embodiments, the method further includes: (j) sending, from the one or more downhole controllers and to the surface controller, the calculated downhole vibration. In some embodiments, the step (c) measures one or more of: a measured weight on bit; a measured torque on bit; and a measured differential pressure. In some embodiments, the step (h) is automatically implemented upon receipt of the first instructions by the surface controller. In some embodiments, the target efficiency parameter and the measured efficiency parameter are associated with bit whirl; and wherein implementing, by the surface controller, the second instructions reduce bit whirl. In some embodiments, the method also includes (k) connecting a first stand to the drill string during a first connection; and (l) connecting a second stand to the drill string during a second connection that is subsequent to the first connection; and (m) touching a bottom of the wellbore with the drill string after the second connection; wherein the steps (c)-(i) occur after the first connection and before touching the bottom of the wellbore with the drill string after the second connection. In some embodiments, the smart downhole system forms a portion of a rotary steerable system that is attached to the drill string. In some embodiments, a bottom hole assembly is attached to the drill string; and wherein the smart downhole system is attached to the drill string at a location that is spaced from the bottom hole assembly.

(4) In some embodiments, the present disclosure includes an apparatus adapted to drill a wellbore including: a drill string; a surface control system that controls movement of the drill string; and a smart downhole system attached to the drill string; wherein the smart downhole system includes: one or more downhole controllers and one or more downhole sensors configured to measure a parameter; and wherein the one or more downhole controllers is configured to: (a) store a target efficiency parameter; (b) receive a measured parameter from the one or more downhole sensors; (c)

calculate an efficiency parameter based on the measured parameter; (d) calculate a difference between the calculated efficiency parameter and the target efficiency parameter; (e) generate first instructions to reduce the difference; and (f) send, to the surface controller, the first instructions; and wherein the surface control system is configured to: (g) generate second instructions based on the first instructions; and (h) implement the second instructions to reduce the difference between the measured efficiency parameter and the target efficiency parameter. In one embodiment, the target efficiency parameter is minimum downhole vibration; and wherein the calculated efficiency parameter is a calculated downhole vibration. In one embodiment, the difference exceeding a threshold indicates that the calculated downhole vibration should be reduced; wherein the first instructions are associated with minimizing the downhole vibration; and wherein the second instructions reduce a feedoff rate to minimize the downhole vibration. In one embodiment, the one or more downhole controllers is further configured to: (i) send, to the surface controller, the calculated downhole vibration. In one embodiment, the measured parameter is one or more of: a measured weight on bit; a measured torque on bit; and a measured differential pressure. In one embodiment, the surface control system is configured to automatically generate the second instructions upon receipt of the first instructions. In one embodiment, the smart downhole system and the surface control system form a closed loop system for optimizing downhole drilling conditions. In one embodiment, the target efficiency parameter and the calculated efficiency parameter are associated with bit whirl; and wherein implementing, by the surface controller, the second instructions reduces bit whirl. In one embodiment, the smart downhole system forms a portion of a rotary steerable system that is attached to the drill string. In one embodiment, a bottom hole assembly is attached to the drill string; and wherein the smart downhole system is attached to the drill string at a location that is spaced from the bottom hole assembly.

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## Description

BRIEF DESCRIPTION OF THE DRAWINGS

(1) The present disclosure is best understood from the following detailed description when read with the accompanying figures. It is emphasized that, in accordance with the standard practice in the industry, various features are not drawn to scale. In fact, the dimensions of the various features may be arbitrarily increased or reduced for clarity of discussion.

(2) FIG. **1** is a schematic diagram of a drilling rig apparatus including a bottom hole assembly (“BHA”), according to one or more aspects of the present disclosure.

(3) FIG. **2** is a data flow related to a portion of the drilling rig apparatus of FIG. **1**, according to one or more aspects of the present disclosure.

(4) FIG. **3** is a flow-chart diagram of a method of using the drilling rig apparatus of FIG. **1**, according to one or more aspects of the present disclosure.

(5) FIG. **4** is a diagrammatic illustration of a node for implementing one or more example embodiments of the present disclosure, according to one or more aspects of the present disclosure.

DETAILED DESCRIPTION

(6) It is to be understood that the present disclosure provides many different embodiments, or examples, for implementing different features of various embodiments. Specific examples of components and arrangements are described below to simplify the present disclosure. These are, of course, merely examples and are not intended to be limiting. In addition, the present disclosure may repeat reference numerals and/or letters in the various examples. This repetition is for the purpose of simplicity and clarity and does not in itself dictate a relationship between the various embodiments and/or configurations discussed. Moreover, the formation of a first feature over or on a second feature in the description that follows may include embodiments in which the first and second features are formed in direct contact and may also include embodiments in which additional

features may be formed interposing the first and second features, such that the first and second features may not be in direct contact.

(7) The apparatus and methods disclosed herein automate the control of a drilling operation, resulting in increased efficiency and speed compared to conventional systems that rely on estimated downhole measurements and require significantly more manual input or pauses to provide for input. Conventionally, and when a drilling operator controls/steers a drilling tool such as the BHA and other drilling equipment, the drilling operator draws on his or her past experiences and the performance of the well to determine the appropriate response to drilling events such as deviation from the actual well path and other unplanned drilling events such as excessive downhole vibration, undesirable bit whirl and bit balling, and the like. This is a very subjective process that is performed by the drilling operator and that is based on his or her judgment. In some instances, the creation of the instructions by the drilling operator is based on estimated downhole measurements that are not accurate. As a result, excessive vibration, bit balling, and bit whirl may occur. In some instances, drilling tools are damaged. The apparatus and methods disclosed herein provide more accurate and timely values for weight on bit, torque on bit, differential pressure, and/or vibration rate, thus allowing for optimization of drilling parameters in real time or near real time. In some embodiments, the apparatus and method may automate the creation, sending, and/or execution of the instructions. Specifically, the apparatus and method disclosed herein relate to a drilling system that includes a smart downhole system with a downhole controller and one or more sensors that monitor downhole drilling parameters. The downhole drilling parameters may include weight on bit, torque on bit, differential pressure, and/or downhole vibration. The smart downhole system calculates an efficiency parameter based on the measured parameters and calculates a difference between a stored target parameter and the calculated efficiency parameter. The downhole computing system or smart downhole system is programmed to generate instructions based on the difference and to send instructions to be implemented and/or considered by the surface control system. The way in which the downhole computing system and the surface control system can be combined to work together further automates portions of a drilling process while also using previously unavailable measured downhole parameters.

(8) Referring to FIG. **1**, illustrated is a schematic view of apparatus **100** demonstrating one or more aspects of the present disclosure. The apparatus **100** is or includes a land-based drilling rig. However, one or more aspects of the present disclosure are applicable or readily adaptable to any type of drilling rig, such as jack-up rigs, semisubmersibles, drill ships, coil tubing rigs, well service rigs adapted for drilling and/or re-entry operations, and casing drilling rigs, among others within the scope of the present disclosure.

(9) Apparatus **100** includes a mast **105** supporting lifting gear above a rig floor **110**. The lifting gear includes a crown block **115** and a traveling block **120**. The crown block **115** is coupled at or near the top of the mast **105**, and the traveling block **120** hangs from the crown block **115** by a drilling line **125**. One end of the drilling line **125** extends from the lifting gear to draw works **130**, which is configured to reel out and reel in the drilling line **125** to cause the traveling block **120** to be lowered and raised relative to the rig floor **110**. The draw works **130** may include a rate of penetration (“ROP”) sensor **130***a*, which is configured for detecting an ROP value or range, and a control system to feed-out and/or feed-in of a drilling line **125**. The other end of the drilling line **125**, known as a dead line anchor, is anchored to a fixed position, possibly near the draw works **130** or elsewhere on the rig.

(10) A hook **135** is attached to the bottom of the traveling block **120**. A drive system **140** is suspended from the hook **135**. A quill **145**, extending from the drive system **140**, is attached to a saver sub—**150**, which is attached to a drill string **155** suspended within a wellbore **160**. Alternatively, the quill **145** may be attached to the drill string **155** directly. The term “quill” as used herein is not limited to a component which directly extends from the drive system **140**, or which is otherwise conventionally referred to as a quill. For example, within the scope of the present

disclosure, the “quill” may additionally or alternatively include a main shaft, a drive shaft, an output shaft, and/or another component which transfers torque, position, and/or rotation from the top drive or other rotary driving element to the drill string, at least indirectly. Nonetheless, albeit merely for the sake of clarity and conciseness, these components may be collectively referred to herein as the “quill.” In the example embodiment depicted in FIG. **1**, the drive system **140** is utilized to impart rotary motion to the drill string **155**. However, aspects of the present disclosure are also applicable or readily adaptable to implementations utilizing other drive systems, such as a power swivel, a rotary table, a coiled tubing unit, a downhole motor, and/or a conventional rotary rig, among others.

(11) The apparatus **100** may additionally or alternatively include a torque sensor **140***a* coupled to or otherwise associated with the drive system **140**. The torque sensor **140***a* may be configured to detect a value or range of the torsion of the quill **145** and/or the drill string **155** (e.g., in response to operational forces acting on the drill string). The drive system **140** may additionally or alternatively include or otherwise be associated with a speed sensor **140***b* configured to detect a value or range of the rotational speed of the quill **145**. The drive system **140**, the draw works **130**, the crown block **115**, the traveling block **120**, drilling line or deadline anchor may additionally or alternatively include or otherwise be associated with a weight-on-bit (“WOB”) or hook load sensor **140***c* (e.g., one or more sensors installed somewhere in the load path mechanisms to detect and calculate WOB, which can vary from rig-to-rig). The WOB sensor **140***c* may be configured to detect a WOB value or range, where such detection may be performed at the drive system **140**, the draw works **130**, or other component of the apparatus **100**. Generally, the hook load sensor **140***c* detects the load on the hook **135** as it suspends the drive system **140** and the drill string **155**. The apparatus **100** may also include a surface control system **162** that is operably coupled to the drive system **140**, the draw works **130**, and one or more pumps of a mud pump system **165**, which delivers drilling fluid to the drill string **155** through a hose or other conduit **170**.

(12) In some embodiments, a mud pump sensor **165***a* monitors the output of the mud pump system **165** and may measure the flow rate produced by the mud pump system **165** and/or a pressure produced by the mud pump system **165**.

(13) The drill string **155** includes interconnected sections of drill pipe **175** and a BHA **180**—which includes a drill bit **185**—is attached to the drill string **155**.

(14) The BHA **180** may include a variety of downhole tools and sensors. For example, the BHA **180** may include a downhole annular pressure sensor **180***a*. The downhole annular pressure sensor **180***a* may be configured to detect a pressure value or range in the annulus-shaped region defined between the external surface of the BHA **180** and the internal diameter of the wellbore **160**, which may also be referred to as the casing pressure, downhole casing pressure, MWD casing pressure, or downhole annular pressure. These measurements may include both static annular pressure (pumps off) and active annular pressure (pumps on).

(15) The BHA **180** may also include a shock/vibration sensor **180***b* that is configured for detecting shock and/or vibration. The BHA **180** may also include delta pressure (ΔP) sensor(s) **180***c* that are configured to detect a pressure differential between outside and inside of the BHA **180** or before and after the drill bit **185**. The BHA **180** may also include one or more torque sensors **180***d*, such as a bit torque sensor, that measures the torque applied to the bit **185** or at a location along the BHA **180**. The one or more torque sensors **180***d* may alternatively be located along the drill string **155** to detect a value or range of the torsion of the drill string **155**.

(16) The BHA **180** may also include a toolface sensor **180***e* configured to estimate or detect the current toolface orientation or toolface angle. The toolface sensor **180***e* may be or include a conventional or future-developed gravity toolface sensor which detects toolface orientation relative to the Earth's gravitational field. Alternatively, or additionally, the toolface sensor **180***e* may be or include a conventional or future-developed magnetic toolface sensor which detects toolface orientation relative to magnetic north or true north. In an example embodiment, a magnetic toolface

sensor may detect the current toolface when the end of the wellbore is less than about 7° from vertical, and a gravity toolface sensor may detect the current toolface when the end of the wellbore is greater than about 7° from vertical. However, other toolface sensors may also be utilized within the scope of the present disclosure, including non-magnetic toolface sensors and non-gravitational inclination sensors. The toolface sensor **180***e* may also, or alternatively, be or include a conventional or future-developed gyro sensor. The apparatus **100** may additionally or alternatively include a WOB sensor **180***f* integral to the BHA **180** and configured to detect WOB at or near the BHA **180**. The BHA **180** may also include an inclination sensor **180***g* configured to detect inclination at or near the BHA **180**. The BHA **180** may also include an azimuth sensor **180***h* configured to detect azimuth at or near the BHA **180**. In some embodiments, the BHA **180** also includes another directional sensor **180***i* (e.g., azimuth, inclination, toolface, combination thereof, etc.) that is spaced along the BHA **180** from one or another directional sensor (e.g., the inclination sensor **180***g*, the azimuth sensor **180***h*). The sensors **180***a*-**180***i* are not limited to the arrangement illustrated in FIG. **1** and may be spaced along the BHA **180** in a variety of configurations.
(17) The detection performed by the sensors described herein may be performed once, continuously, periodically, and/or at random intervals. The detection may be manually triggered by an operator or other person accessing a human-machine interface ("HMI") or GUI, or automatically triggered by, for example, a triggering characteristic or parameter satisfying a predetermined condition (e.g., expiration of a time period, drilling progress reaching a predetermined depth, drill bit usage reaching a predetermined amount, etc.). Such sensors and/or other detection means may include one or more interfaces which may be local at the well/rig site or located at another, remote location with a network link to the system.
(18) The BHA **180** may include one or more measurement-while-drilling ("MWD") or wireline conveyed instruments, flexible connections, a rotary steerable system ("RSS") or a mud motor, stabilizers, and/or drill collars, among other components. The downhole MWD may be configured for the evaluation of physical properties such as pressure, temperature, torque, weight-on-bit ("WOB"), vibration, inclination, azimuth, toolface orientation in three-dimensional space, and/or other downhole parameters. These measurements may be made downhole, stored in solid-state memory for some time, sent to other downhole tools, and downloaded from the instrument(s) at the surface and/or transmitted real-time to the surface. Data transmission methods may include, for example, digitally encoding data and transmitting the encoded data to the surface, possibly as pressure pulses in the drilling fluid or mud system, acoustic transmission through the drill string **155**, electronic transmission through a wireline or wired pipe, and/or transmission as electromagnetic pulses. The MWD tools and/or other portions of the BHA **180** may have the ability to store measurements for later retrieval via wireline and/or when the BHA **180** is tripped out of the wellbore **160**.
(19) In some embodiments, the BHA **180** also includes a downhole controller **190** that is operably coupled to any one or more of the sensors **180***a*-**180***i*, the MWD tools, and other components of the BHA **180** itself. In some embodiments, the downhole controller **190** comprises one or more downhole controllers. Generally, the downhole controller **190** is configured to calculate efficiency parameters from parameters obtained from the sensors of the BHA **180**, including those in the MWD tools; transmit the calculated efficiency measurements and/or parameters obtained from the sensors of the BHA **180** to the surface control system **162**; control/instruct components of the BHA **180**; and/or transmit operational control signals or other feedback to the surface control system **162** via wired or wireless transmission means which, for the sake of clarity, are not depicted in FIG. **1**. Generally, the controller **190** and the sensors in the BHA **180** (e.g., the sensors **180***a*-**180***i* and the sensors in the MWD tools) form a smart downhole system **195**.
(20) The smart downhole system **195** is configured to control or assist in the control of one or more components of the apparatus **100** based on measured/calculated downhole conditions. For example, the smart downhole system **195** may be configured to transmit operational control signals or

instructions to the surface control system **162**, the draw works **130**, the drive system **140**, other components of the BHA **180**, and/or the mud pump system **165** in response to data obtained by downhole sensors. In one embodiment, the controller **190** of the smart downhole system **195** receives data from the MWD tools, any one or more of the sensors **180***a*-**180***i*, data from the surface control system **162**, etc.

(21) In an example embodiment, the apparatus **100** may also include a rotating blow-out preventer ("BOP") **200**, such as if the wellbore **160** is being drilled utilizing under-balanced or managed-pressure drilling methods. In such embodiment, the annulus mud and cuttings may be pressurized at the surface, with the actual desired flow and pressure possibly being controlled by a choke system, and the fluid and pressure being retained at the well head and directed down the flow line to the choke by the rotating BOP **200**. The apparatus **100** may also include a surface casing annular pressure sensor **205** configured to detect the pressure in the annulus defined between, for example, the wellbore **160** (or casing therein) and the drill string **155**. It is noted that the meaning of the word "detecting," in the context of the present disclosure, may include detecting, sensing, measuring, calculating, and/or otherwise obtaining data. Similarly, the meaning of the word "detect" in the context of the present disclosure may include detect, sense, measure, calculate, and/or otherwise obtain data.

(22) Generally, the surface control system **162** and the smart downhole system **195**: monitor, in real-time, tool settings and drilling operations relating to a wellbore; create and/or modify drilling instructions based on the monitored drilling operations; monitor the responsiveness of drilling equipment used in the drilling operation; and identify potential problems with the drilling operations. As used herein, the term "real-time" is meant to encompass close to real-time, such as within about 10 seconds, preferably within about 5 seconds, and more preferably within about 2 seconds. Near real time includes the amount of time between connections of consecutive stands or the amount of time between a first stand being connected and the drill string **155** touching bottom after a second, consecutive stand has been connected.

(23) FIG. **2** is a diagrammatic illustration of a data flow **210** involving at least a portion of the apparatus **100** according to one embodiment. Generally, the surface control system **162** is configured to control or assist in the control of one or more components of the apparatus **100**. For example, the surface control system **162** may be configured to transmit operational control signals to the draw works **130** via a draw works control system **215**, the drive system **140** via a drive control system **220**, the mud pump system **165** via a mud pump control system **225**, and/or the BHA **180**. The surface control system **162** may be a stand-alone component installed near the mast **105** and/or other components of the apparatus **100**. In an example embodiment, the surface control system **162** includes one or more systems located in a control room proximate the mast **105**, such as the general-purpose shelter often referred to as the "doghouse" serving as a combination tool shed, office, communications center, and general meeting place. The surface control system **162** may be configured to transmit the operational control signals to the drive control system **220**, the draw works control system **215**, the mud pump control system **225**, and/or the BHA **180** via wired or wireless transmission means. In some embodiments the drive control system **220** includes the torque sensor **140***a*, the quill position sensor, the hook load sensor **140***c*, the pump pressure sensor, the MSE sensor, and the rotary RPM sensor, and/or other means for controlling the rotational position, speed and direction of the quill or other drill string component coupled to the drive system (such as the quill **145** shown in FIG. **1**). The drive control system **220** is configured to receive a drive control signal, which directs the position (e.g., azimuth), spin direction, spin rate, and/or oscillation of the quill **145**. The drive control system **220** is not required to include a top drive, but instead may include other drive systems, such as a power swivel, a rotary table, a coiled tubing unit, a downhole motor, and/or a conventional rotary rig, among others. In some embodiments, the mud pump control system **225** includes a mud pump surface control system and/or other means for controlling the flow rate and/or pressure of the output of the mud pump system **165** and any

associated sensors, such as the mud pump sensor **165***a*, for monitoring the output of the mud pump system **165**. In some embodiments, the draw works control system **215** includes the draw works surface control system and/or other means for controlling the feed-out and/or feed-in of the drilling line **125**. Such control may include rotational control of the draw works (in v. out) to control the height or position of the hook **135** and may also include control of the rate the hook **135** ascends or descends.

(24) Generally, the surface control system **162** is operably coupled to or includes a graphical user interface ("GUI") **230**. The GUI **230** includes an input mechanism **235** for user-inputs or drilling parameters. The input mechanism **235** may include a touch-screen, keypad, voice-recognition apparatus, dial, button, switch, slide selector, toggle, joystick, mouse, data base and/or other conventional or future-developed data input device. Such input mechanism **235** may support data input from local and/or remote locations. Alternatively, or additionally, the input mechanism **235** may include means for user-selection of input parameters, user-selection of target settings, selecting to implement the selected instruction combination, and/or selecting a type of tool that forms a portion of the BHA **180**, such as via one or more drop-down menus, input windows, etc. In general, the input mechanism **235** and/or other components within the scope of the present disclosure support operation and/or monitoring from stations on the rig site, as well as, one or more remote locations with a communications link to the system, network, local area network ("LAN"), wide area network ("WAN"), Internet, satellite-link, and/or radio, among other means. The GUI **235** may also include a display **240** for visually presenting information to the driller in textual, graphic, or video form. The display **240** may also be utilized by the driller to input the input parameters in conjunction with the input mechanism **235**. For example, the input mechanism **235** may be integral to or otherwise communicably coupled with the display **240**. Depending on the implementation, the display **240** may include, for example, an LED or LCD display computer monitor, touchscreen display, television display, a projector, or other display device. The GUI **230** and the surface control system **162** may be discrete components that are interconnected via wired or wireless means. Alternatively, and in some embodiments, the GUI **230** is an integral component of the surface control system **162**.

(25) In some embodiments and as illustrated in FIG. **2**, the smart downhole system **195** is configured to measure parameters using the plurality of sensors (e.g., the sensors **180***a*-**180***i* and other downhole sensors) and receive and/or generate target efficiency parameters. In some embodiments, the downhole controller **190** calculates an efficiency parameter using, or based on, the measured parameters. The target efficiency parameters may be received by the smart downhole system **195** before the smart downhole system **195** is positioned downhole or may be sent from the surface control system **162** to the smart downhole system **195** when the smart downhole system **195** is downhole. In some embodiments, the smart downhole system **195** generates the target efficiency parameters based on measured downhole conditions, a well plan, and/or other drilling instructions sent from the surface control system **162**.

(26) Generally, a target efficiency parameter is or relates to an ideal or desired downhole condition or measurement and may be expressed as a minimum value, a maximum value, an acceptable range of values, or merely the minimization or maximation of a value. One example of a target efficiency parameter relates to reducing downhole vibration. In one embodiment, the target efficiency parameter may be a threshold value for downhole vibration that should not be exceeded. In another embodiment, the target efficiency parameter is the minimization of downhole vibration. Downhole vibration may be caused by touching bottom too fast or touching bottom too fast in combination with other downhole conditions that are created by the surface control system **162**. The surface control system, with conventional systems, does not receive data relating to these downhole conditions in real time or near real time, and therefore, cannot optimize instructions at the surface to reduce or eliminate downhole vibration. For example, the feedoff rate may be used to estimate an incorrect speed at which the BHA **180** is touching bottom, with the incorrect speed resulting in

downhole vibration. Without knowing the values for the measured downhole vibration, a conventional surface control system has no indication that the feedoff rate should be reduced to mitigate downhole vibration. The smart downhole system **195**, however, can compare the target vibration value with a calculated vibration value to determine if/when downhole vibration exceeds the target value. When the downhole vibration exceeds the target value, the smart downhole system **195** may determine that the feedoff rate should be reduced in order to reduce downhole vibration. In some embodiments, the smart downhole system **195** then generates instructions to reduce the difference between the target and calculated efficiency parameter. In this example, the instructions generally relate to reducing the speed at which the drill string **155** is lowered. In some embodiments, the instructions sent from the smart downhole system **195** may include generic instructions such as “reduce feedoff rate.” In some embodiments, the calculated efficiency parameters or measured parameters are sent from the smart downhole system **195** to the surface control system **162**.
(27) In an example embodiment, as illustrated in FIG. **3** with continuing reference to FIG. **1-2**, a method **300** of operating the apparatus **100** includes storing, in the downhole controller **190**, a target efficiency parameter at step **305**; drilling the wellbore **160** using the drill string **155** at step **310**; measuring, by one or more downhole sensors, a parameter at step **315**; calculating, by the downhole controller **190**, an efficiency parameter based on the measured parameter at step **320**; calculating, by the downhole controller **190**, a difference between the calculated efficiency parameter and the target efficiency parameter at step **325**; generating, by the downhole controller, first instructions to reduce the difference at step **330**; sending, from the downhole controller **190** and to the surface control system **162**, the first instructions at step **335**; generating, by the surface control system **162**, second instructions based on the first instructions at step **340**; and implementing, by the surface control system **162**, the second instructions to reduce the difference between the measured efficiency parameter and the target efficiency parameter at step **345**.
(28) In some embodiments and at the step **305**, the downhole controller **190** stores the target efficiency parameter. As noted above, the storing of the target efficiency parameter may occur while the controller **190** is not downhole or may be sent to the controller **190** when the controller **190** is downhole. In some embodiments, the smart downhole system **195** receives the target efficiency parameter from the surface control system **162** via a wired or a wireless connection or via any other means. In other embodiments, the smart downhole system **195** generates the target efficiency parameter before storing the target efficiency parameter.
(29) In some embodiments and at the step **310**, the wellbore **160** is drilled using the BHA **180**.
(30) In some embodiments and at the step **315**, one or more downhole sensors measures a parameter. As noted above, in some embodiments, the parameter relates to downhole vibration. In other embodiments, the parameter relates to bit balling and the prevention of bit balling, and therefore, is a measurement related to bit whirl. In some embodiments, the sensor may be or include: a sensor measuring actual weight on bit, such as the WOB sensor **180***f*; a sensor measuring an actual differential pressure, such as the delta pressure (ΔP) sensor(s) **180***c*; a sensor measuring an actual torque on bit, such as the torque sensors **180***d*; a sensor measuring downhole vibration, such as the shock/vibration sensor **180***b*. The sensor may detect an unplanned, dynamic drilling event related to vibration and sends those measurements to the controller **190**.
(31) In some embodiments and at the step **320**, the downhole controller **190** calculates an efficiency parameter based on the measured parameter. In some embodiments, the efficiency parameter is downhole vibration and the downhole controller **190** calculates for the downhole vibration rate based on the measured parameters. In some embodiments, information from the surface control system **162** is sent to the smart downhole system **195** to enable the smart downhole system **195** to calculate the efficiency parameter. For example, depth information may be sent to the smart downhole system **195**. In some embodiments, the efficiency parameter indicates the potential or existence of bit whirl and/or bit balling.

(32) In some embodiments and at the step **325**, the downhole controller **190** calculates the difference between the stored efficiency parameter and that of the calculated efficiency parameter. In some embodiments, if the difference is below a certain threshold, then the method **300** returns to step **315**. In some embodiments, if the difference is above a certain threshold, then the method **300** proceeds to the step **330**.
(33) In some embodiments and at the step **330**, the downhole controller creates first instructions to reduce the difference between the target efficiency parameter and the calculated efficiency parameter. In some embodiments, the first instructions are to change a drilling parameter that is controlled by the surface control system **162**. For example, the change could be a reduction or increase to a drilling parameter that is controlled by the surface control system **162**. The drilling parameter that is controlled by the surface control system **162** may be the feedoff rate, for example. As such, the first instruction may include "reduce the feedoff rate." In some embodiments, the first instructions include the measured parameter and/or calculated efficiency parameter, such as the calculated downhole vibration. In some embodiments, the first instructions relate to changing the feedoff rate, WOB, or downhole torque.
(34) In some embodiments and at the step **335**, the downhole controller **190** sends the generated first instructions to the surface control system **162**. In some embodiments, the first instructions are sent via wired or wireless transmission means. In some embodiments, the actual downhole weight on bit, actual torque on bit, and/or actual differential pressure measurements are sent to the surface control system **162**.
(35) In some embodiments and at the step **340**, the surface control system **162** generates second instructions based on the first instructions. For example, and when the first instructions are to reduce the feedoff rate, the surface control system **162** generates specific instructions as to how much the feedoff rate should be reduced and those specific instructions are the second instructions. For example, and when the first instructions are to "reduce the feedoff rate," the second instructions can include instructions with a numerical value of a target feedoff rate. In some embodiments, the second instructions are the same as the first instructions. In other embodiments, however, the surface control system **162** uses the first instructions, along with other drilling parameters, to create the second instructions. For example, when the first instructions are to reduce the feedoff rate, the surface control system **162** determines the existing or historical feedoff rate in order to calculate a new, target feedoff rate that is lower than the previous feedoff rate. In some embodiments, the second instructions are automatically generated upon receipt of the first instructions.
(36) In some embodiments and at the step **345**, the second instructions are implemented by the surface control system **162**. The second instructions may control the surface systems in an effort to reduce the difference between the calculated efficiency parameter and the target efficiency parameter. The second instructions may be displayed on the GUI **230**, and the driller may select to approve the second instructions. In some embodiments, the second instructions are automatically executed by the surface control system **162**. In other embodiments, the driller may add additional data at the surface to alter the second instructions before the surface control system **162** implements the second instructions. In some embodiments, the driller is required to review and/or approve one or more steps of method **300**.
(37) In some embodiments, the steps **315**, **320**, **325**, **330**, **335**, **340**, and **345** occur after a first stand is added to the drill string **155** and before the drill string **155** touches bottom after a second subsequent stand is added to the drill string **155**. In some embodiments, the steps **315**, **320**, **325**, **330**, **335**, **340**, and **345** occurs after the first stand is added but before a third stand, which is subsequent to the second stand, is added to the drill string **155**. For example, when the drill string **155** touches down after a first connection, and when there is enough vibration for the smart downhole system **195** to generate and send instructions up to the surface control system **162**, the generation of the first and second instructions occurs before a subsequent touching down of the

drill string **155**. In some embodiments, the sending of the instructions to the surface control system **162** may occur any time before the BHA **180** is lowered down to touch bottom for the next connection. In some embodiments, this optimization of downhole drilling conditions is based on measured downhole conditions and occurs between a first connection and touching down after adding a second connection. In some embodiments and as noted above, the optimization of downhole drilling conditions occurs between a first and third connection. This is an improvement to conventional systems, which require the BHA **180** to be tripped out before the measured downhole conditions can be accessed.

(38) In some embodiments, the calculated efficiency parameter and/or the measured parameters are sent from the smart downhole system **195** to the surface control system **162** in addition to the first instructions so that surface control system **162** can be calibrated or trained in response to drilling conditions.

(39) In one or more embodiments, the target efficiency parameter may be updated while drilling and sent to the smart downhole system **195**.

(40) In some embodiments, the method **300** also includes sending the calculated downhole vibration measurement and/or measured parameters before, contemporaneously, or after step **335**.

(41) The smart downhole system **195** and the method **300** may be altered in a variety of ways. In some embodiments, and when the BHA **180** includes an RSS, the well plan is stored in the downhole controller **190** and the downhole controller **190** compares the location of the BHA **180** with the target well path to create instructions that alter the direction of the RSS so that the RSS is steered by the downhole controller **190**. As such, the downhole controller **190** and the RSS form a downhole control loop. That is, a first closed-loop control system is formed in which the input is the target inclination angle and a second closed-loop control system in which the input is the target azimuth angle. Thus, in some embodiments, any individual aspect (or combination thereof) of steering, turning left and right, or changing the inclination is set up in a closed loop mode. In some embodiments and when set in closed loop mode, the azimuth is set as a target and the RSS will continuously target the azimuth using a closed loop with a regulator, for example a PID regulator (Proportional Integral Derivative) or logic rules, to steer and to maintain a heading. If it is pushed “off course” for any reason, the apparatus **100** will try to steer back. In closed loop inclination control, the inclination target will be set and then the RSS will steer towards the target using a build up rate that can be varied to suit the plan. Typically, the build up rate and turn rate setting can be estimated, based on the known performance of the system, but the actual build rate and turn rate will depend on the geology and drilling parameters and therefore may need adjusting from time to time.

(42) In addition to the steering of the RSS and in some embodiments, the downhole controller **190** creates a third downhole control loop with the surface equipment by sending instructions to the surface control system **162** so that the surface control system **162** alters drilling parameters at the surface to affect or optimize the downhole conditions. Thus, the downhole controller **190** steers the RSS in response to downhole location measurements and also optimizes downhole drilling conditions by sending instructions to the surface control system **162**. The use of the smart downhole system **195** allows for drilling instructions to be based on actual downhole conditions and optimized using a closed loop system, instead of being based on estimated conditions. As shock, vibration, whirl, stick-slip and other impacts will affect the BHA **180** in various ways and may cause critical parts of the BHA **180** to fail and hole quality to deteriorate, identification and correction of these conditions in real time or near real time is ideal.

(43) While the smart downhole system **195** is described above as being associated with the BHA **180** or forming a portion of the BHA **180**, in some embodiments the smart downhole system **195** is spaced along the drill string **155** and apart from the BHA **180**. For example, a smart downhole system **195** may be located “uphole” from the BHA by over 100 joints or by at least 5% of the drill string **155** length so that the local conditions for that smart downhole system **195** are monitored.

When the smart downhole system **195** is spaced from the BHA **180**, a closed loop system is created between the smart downhole system **195** and the surface control system **162**. The apparatus **100** may include one smart downhole system **195** that is spaced from the BHA **180** or multiple smart downhole systems—with one being located at the BHA **180** and one spaced from the BHA **180**. When there are multiple smart downhole systems **195**, the smart downhole systems **195** may be in communication downhole to prioritize/consolidate instructions being sent to the surface control system **162**. However, in some embodiments the multiple smart downhole systems **195** send separate instructions, and the surface control system **162** receives both sets of instructions and prioritizes one set of instructions depending on the local drilling conditions experienced at each smart downhole system **195**.
(44) In some embodiments, using the method **300** and/or the apparatus **100**, the smart downhole system **195** quickly generates drilling instructions based on the relationship between stored instructions and/or parameters and the results of those instructions and/or parameters. Thus, drilling conditions are optimized and the actual well path more closely aligns with the target well path, the speed at which drilling along the target well path improves, and/or the downhole tools experience less damages and wear therefore resulting in fewer trips out and reduced overall drilling time. In some embodiments, the method **300** and apparatus **100** produce more accurate data by calculating and acting upon, in near real time, the actual weight on bit, actual differential pressure, and actual torque on bit. In some embodiments, the first instructions being sent from the smart downhole system **195** and the automatic generation of the second instructions allow for drilling instructions to be implemented sooner than with conventional systems. In some embodiments, mitigating downhole vibration during a drilling event allows for a better method of drilling. In some embodiments, the apparatus **100** mitigates vibration in near real time.
(45) Moreover, shock, vibration, whirl, and other impacts will affect the BHA **180** in various ways. It may cause critical parts of the BHA **180**, sensors, tools, mechanical assemblies, to fail, parts to break, drill-bits to fail, hole quality to deteriorate and if these conditions can be identified in real time or near real time, then corrective action can be taken. Thus, using the method **300** and/or the apparatus **100**, high vibration drilling events, improper feedoff rates, excessive bit whirl, and bit balling are quickly identified and resolved, which reduces the likelihood or frequency of equipment failure and/or well control issues.
(46) Methods within the scope of the present disclosure may be local or remote in nature. These methods, and any controllers discussed herein, may be achieved by one or more intelligent adaptive controllers, programmable logic controllers, artificial neural networks, and/or other adaptive and/or "learning" controllers or processing apparatus. For example, such methods may be deployed or performed via PLC, PAC, PC, one or more servers, desktops, handhelds, and/or any other form or type of computing device with appropriate capability.
(47) The term "about," as used herein, should generally be understood to refer to both numbers in a range of numerals. For example, "about 1 to 2" should be understood as "about 1 to about 2." Moreover, all numerical ranges herein should be understood to include each whole integer, or 1/10 Of an integer, within the range.
(48) In an example embodiment, as illustrated in FIG. **4** with continuing reference to FIGS. **1-3**, an illustrative node **1000** for implementing one or more embodiments of one or more of the above-described networks, elements, methods and/or steps, and/or any combination thereof, is depicted. The node **1000** includes a microprocessor **1000***a*, an input device **1000***b*, a storage device **1000***c*, a video controller **1000***d*, a system memory **1000***c*, a display **1000***f*, and a communication device **1000***g* all interconnected by one or more buses **1000***h*. In several example embodiments, the storage device **1000***c* may include a floppy drive, hard drive, CD-ROM, optical drive, any other form of storage device and/or any combination thereof. In several example embodiments, the storage device **1000***c* may include, and/or be capable of receiving, a floppy disk, CD-ROM, DVD-ROM, or any other form of computer-readable non-transitory medium that may contain executable

instructions. In several example embodiments, the communication device **1000*g*** may include a modem, network card, or any other device to enable the node to communicate with other nodes. In several example embodiments, any node represents a plurality of interconnected (whether by intranet or Internet) computer systems, including without limitation, personal computers, mainframes, PDAs, tablets, and cell phones.
(49) In several example embodiments, one or more of the surface control system **162**, the smart downhole system **195**, the GUI **235**, and any of the sensors, includes the node **1000** and/or components thereof, and/or one or more nodes that are substantially similar to the node **1000** and/or components thereof.
(50) In several example embodiments, software includes any machine code stored in any memory medium, such as RAM or ROM, and machine code stored on other devices (such as floppy disks, flash memory, or a CD ROM, for example). In several example embodiments, software may include source or object code. In several example embodiments, software encompasses any set of instructions capable of being executed on a node such as, for example, on a client machine or server.
(51) In several example embodiments, a database may be any standard or proprietary database software, such as Oracle, Microsoft Access, SyBase, or DBase II, for example. In several example embodiments, the database may have fields, records, data, and other database elements that may be associated through database specific software. In several example embodiments, data may be mapped. In several example embodiments, mapping is the process of associating one data entry with another data entry. In an example embodiment, the data contained in the location of a character file can be mapped to a field in a second table. In several example embodiments, the physical location of the database is not limiting, and the database may be distributed. In an example embodiment, the database may exist remotely from the server, and run on a separate platform. In an example embodiment, the database may be accessible across the Internet. In several example embodiments, more than one database may be implemented.
(52) In several example embodiments, while different steps, processes, and procedures are described as appearing as distinct acts, one or more of the steps, one or more of the processes, and/or one or more of the procedures could also be performed in different orders, simultaneously and/or sequentially. In several example embodiments, the steps, processes and/or procedures could be merged into one or more steps, processes and/or procedures.
(53) It is understood that variations may be made in the foregoing without departing from the scope of the disclosure. Furthermore, the elements and teachings of the various illustrative example embodiments may be combined in whole or in part in some or all of the illustrative example embodiments. In addition, one or more of the elements and teachings of the various illustrative example embodiments may be omitted, at least in part, and/or combined, at least in part, with one or more of the other elements and teachings of the various illustrative embodiments.
(54) Any spatial references such as, for example, “upper,” “lower,” “above,” “below,” “between,” “vertical,” “horizontal,” “angular,” “upwards,” “downwards,” “side-to-side,” “left-to-right,” “right-to-left,” “top-to-bottom,” “bottom-to-top,” “top,” “bottom,” “bottom-up,” “top-down,” “front-to-back,” etc., are for the purpose of illustration only and do not limit the specific orientation or location of the structure described above.
(55) In several example embodiments, one or more of the operational steps in each embodiment may be omitted or rearranged. Moreover, in some instances, some features of the present disclosure may be employed without a corresponding use of the other features. Moreover, one or more of the above-described embodiments and/or variations may be combined in whole or in part with any one or more of the other above-described embodiments and/or variations.
(56) Although several example embodiments have been described in detail above, the embodiments described are example only and are not limiting, and those of ordinary skill in the art will readily appreciate that many other modifications, changes and/or substitutions are possible in the example

embodiments without materially departing from the novel teachings and advantages of the present disclosure. Accordingly, all such modifications, changes and/or substitutions are intended to be included within the scope of this disclosure as defined in the following claims. In the claims, means-plus-function clauses are intended to cover the structures described herein as performing the recited function and not only structural equivalents, but also equivalent structures.

## Claims

1. A method of drilling a wellbore using a drill string, one or more controllers, and one or more sensors, the one or more controllers including a drilling controller adapted to control movement of the drill string, which method comprises: connecting a first stand to the drill string during a first connection; drilling the wellbore using the drilling controller to control movement of the drill string; measuring, by the one or more sensors, a parameter; determining, by at least one of the one or more controllers: an efficiency parameter based on the measured parameter; a difference between the determined efficiency parameter and a target efficiency parameter; instructions to reduce the difference between the determined efficiency parameter and the target efficiency parameter, at least a first portion of which instructions are implementable by the drilling controller; connecting a second stand to the drill string during a second connection that is subsequent to the first connection; touching a bottom of the wellbore with the drill string after the second connection; and implementing, by the drilling controller, the at least a first portion of the instructions to reduce the difference between the determined efficiency parameter and the target efficiency parameter.
2. The method of claim 1, wherein: the measured parameter includes a measured downhole vibration; the target efficiency parameter includes a target downhole vibration; and the difference exceeding a threshold indicates that the measured downhole vibration should be reduced.
3. The method of claim 1, wherein the parameter measured by the one or more sensors includes one or more of: a measured weight on bit; a measured torque on bit; a measured differential pressure.
4. The method of claim 1, wherein: the target efficiency parameter and the determined efficiency parameter are associated with bit whirl; and implementing, by the drilling controller, the at least a first portion of the instructions reduces bit whirl.
5. The method of claim 1, wherein the at least one of the one or more controllers comprises one or more downhole controllers.
6. The method of claim 5, wherein the one or more downhole controllers form part of a rotary steerable system attached to the drill string.
7. The method of claim 5, wherein: a bottom hole assembly is attached to the drill string; and the one or more downhole controllers are attached to the drill string at a location that is spaced apart from the bottom hole assembly.
8. The method of claim 5, wherein the drilling controller comprises a surface controller.
9. The method of claim 8, which further comprises: sending, from the one or more downhole controllers to the surface controller, at least a second portion of the instructions.
10. The method of claim 9, which further comprises: determining, by the surface controller, the at least a first portion of the instructions based on the at least a second portion of the instructions.
11. An apparatus adapted to drill a wellbore, the apparatus comprising: a drill string; one or more controllers, including a drilling controller, wherein the drilling controller is adapted to control movement of the drill string to drill the wellbore after a first stand is connected to the drill string via a first connection; and one or more sensors, wherein the one or more sensors are adapted to measure a parameter while the drilling controller controls movement of the drill string to drill the wellbore; wherein at least one of the one or more controllers is adapted to determine: an efficiency parameter based on the measured parameter; a difference between the determined efficiency parameter and a target efficiency parameter; and instructions to reduce the difference between the determined efficiency parameter and the target efficiency parameter, at least a first portion of which

instructions are implementable by the drilling controller; and wherein the drilling controller is further adapted to implement the at least a first portion of the instructions, to reduce the difference between the determined efficiency parameter and the target efficiency parameter, after a bottom of the wellbore is touched with the drill string following connection of a second stand to the drill string via a second connection that is subsequent to the first connection.
12. The apparatus of claim 11, wherein: the parameter adapted to be measured by the one or more sensors includes a measured downhole vibration; the target efficiency parameter includes a target downhole vibration; and the difference exceeding a threshold indicates that the measured downhole vibration should be reduced.
13. The apparatus of claim 11, wherein the parameter adapted to be measured by the one or more sensors includes one or more of: a measured weight on bit; a measured torque on bit; a measured differential pressure.
14. The apparatus of claim 11, wherein: the target efficiency parameter and the determined efficiency parameter are associated with bit whirl; and the at least a first portion of the instructions adapted to be implemented by the drilling controller reduce bit whirl.
15. The apparatus of claim 11, wherein the at least one of the one or more controllers comprises one or more downhole controllers.
16. The apparatus of claim 15, wherein the one or more downhole controllers form part of a rotary steerable apparatus attached to the drill string.
17. The apparatus of claim 15, further comprising a bottom hole assembly attached to the drill string; wherein the one or more downhole controllers are attached to the drill string at a location that is spaced apart from the bottom hole assembly.
18. The apparatus of claim 15, wherein the drilling controller comprises a surface controller.
19. The apparatus of claim 18, wherein the one or more downhole controllers are adapted to send at least a second portion of the instructions to the surface controller.
20. The apparatus of claim 19, wherein the surface controller is adapted to determine the at least a first portion of the instructions based on the at least a second portion of the instructions.