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(54) **Titre : CONTROLE ELECTRONIQUE DE CONDITIONS DE FORAGE D'UN DISPOSITIF DE COMMANDE ROTATIF PENDANT DES OPERATIONS DE FORAGE**

(54) **Title: ELECTRONICALLY MONITORING DRILLING CONDITIONS OF A ROTATING CONTROL DEVICE DURING DRILLING OPERATIONS**

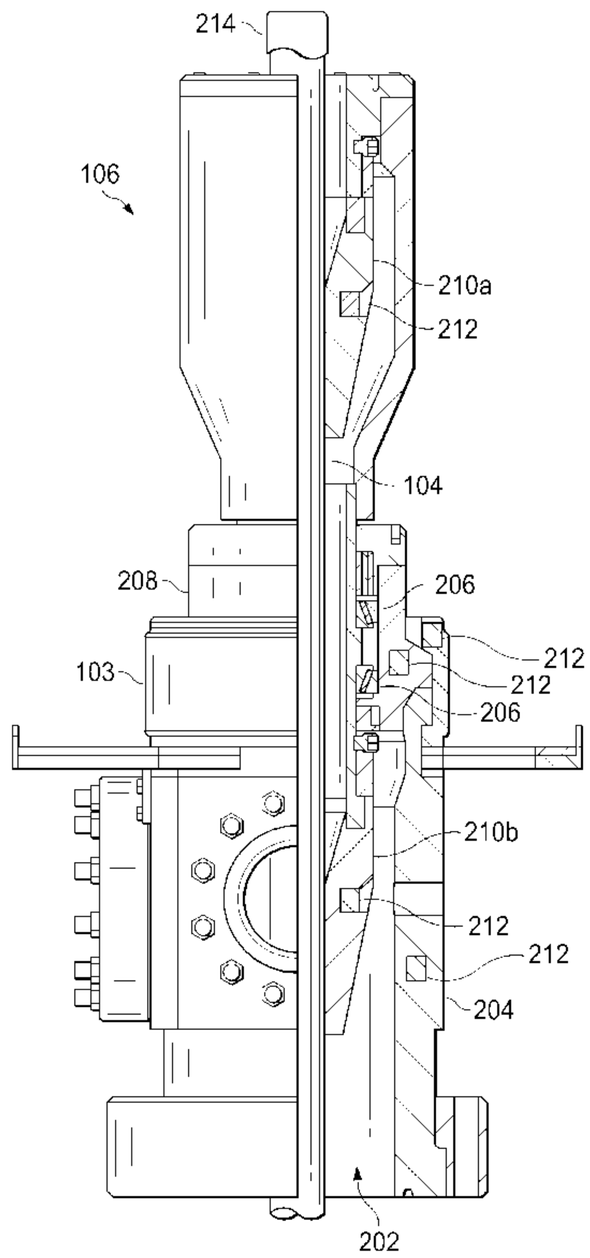


FIG. 2

(57) **Abrégé/Abstract:**
In accordance with some embodiments of the present disclosure, a drilling system comprises a rotating control device (RCD). A plurality of sensors included in or in proximity to the RCD are configured to detect drilling conditions associated with the RCD during a drilling operation. A control system is configured to determine an adjustment to a drilling parameter based on the drilling conditions.

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(54) Title: ELECTRONICALLY MONITORING DRILLING CONDITIONS OF A ROTATING CONTROL DEVICE DURING DRILLING OPERATIONS

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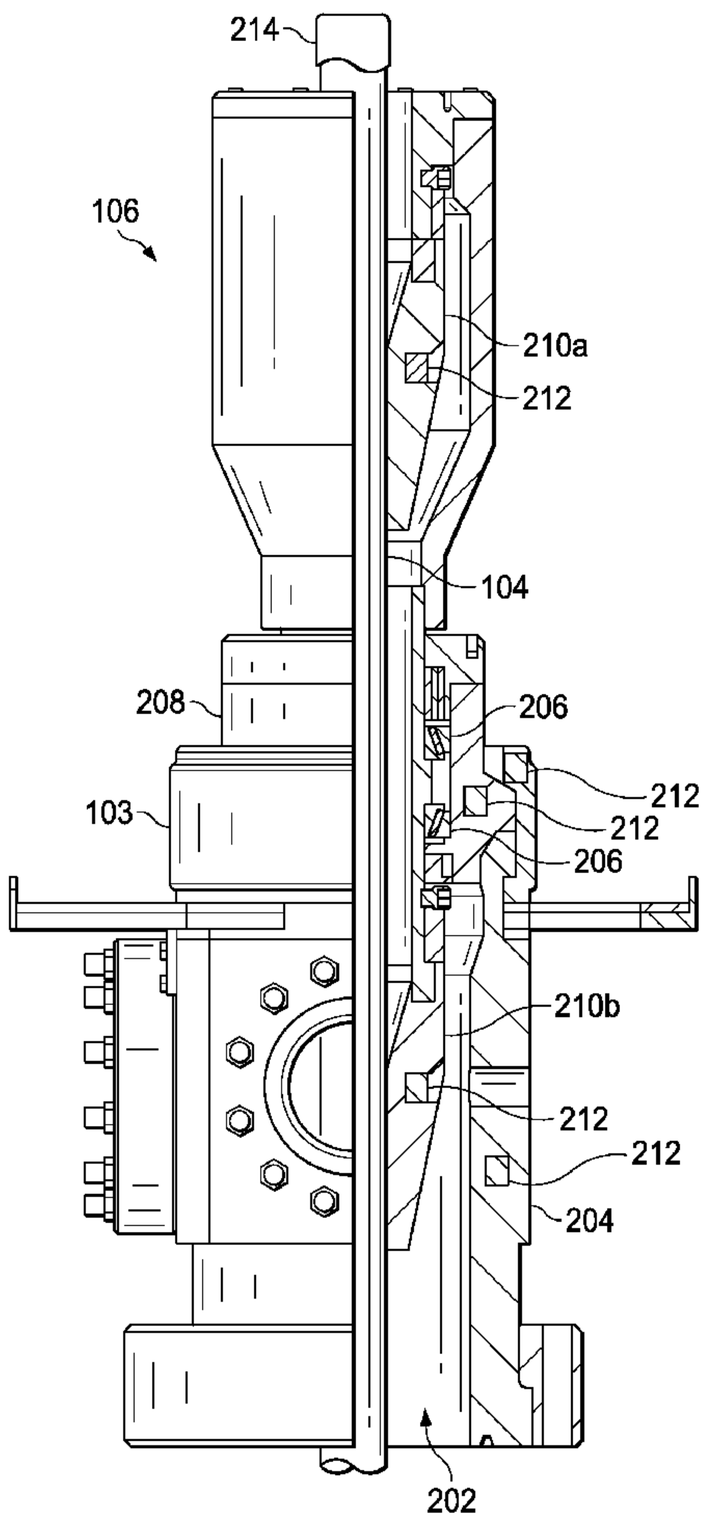


FIG. 2

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ELECTRONICALLY MONITORING DRILLING CONDITIONS OF A ROTATING CONTROL DEVICE DURING DRILLING OPERATIONS

PRIORITY CLAIM

This application claims priority under 35 U.S.C. § 119 to U.S. Provisional Patent Application Serial Number 61/747,704 filed December 31, 2012. The content of which is incorporated by reference herein in its entirety.

TECHNICAL FIELD

The present disclosure relates generally to equipment used and operations performed in connection with well drilling operations and, more particularly, to electronically monitoring drilling properties of a rotating control device during drilling operations.

BACKGROUND

Drilling operations may be performed in a variety of locations and settings. Some drilling operations may be performed on land, and a wellbore may be formed by drilling through rock directly beneath a drilling system. Some drilling operations may be performed offshore, and a wellbore may be formed by first passing through water and then drilling through the seabed. When drilling, a gap (typically referred to as an annulus) may be present between the drill string and the casing and/or outside of the wellbore. In some drilling operations, the annulus may be closed during drilling operations. Some closed annulus drilling operations may include Managed Pressure Drilling (MPD), underbalanced drilling, mud cap drilling, air drilling, and mist drilling

When performing closed annulus drilling operations, a rotating control device (RCD), also referred to as a rotating drilling device, rotating drilling head, rotating flow diverter, pressure control device and rotating annular, may be used to divert drilling fluids returning from the well. The drilling fluids may be diverted into separators, chokes and other equipment. The RCD may function to close off the annulus around a drill string during drilling operations. The sealing mechanism of the RCD, typically referred to as a seal element or packer, is operable to maintain a dynamic seal on the annulus. This may enable chokes to control pressure of the annulus at the surface drilling operations. For example, during underbalanced drilling, there is a net flow out of the drilling fluid from the annulus, creating a back pressure. This flow (and back pressure) may be controllable using chokes placed at intervals along the annulus in fluid communication with the

drilling fluid. These chokes may be selectively operated from the surface of the drilling operations. The seal element further allows drilling to continue while controlling influx of formation fluids.

BRIEF DESCRIPTION OF THE DRAWINGS

For a more complete understanding of the present disclosure and its features, reference is now made to the following description, taken in conjunction with the accompanying drawings, in which:

FIGURE 1 illustrates an example embodiment of a drilling system configured to perform closed annulus drilling operations in accordance with some embodiments of the present disclosure;

FIGURE 2 illustrates a partial cross-sectional view of a rotating control device including sensors to measure drilling conditions associated with the device in accordance with some embodiments of the present disclosure;

FIGURE 3 illustrates a block diagram of a control system configured to receive measurements from the sensors associated with the rotating control device of FIGURE 2 in accordance with some embodiments of the present disclosure;

FIGURES 4 illustrates a flow chart of an example method for monitoring drilling conditions associated with a rotating control device during drilling operations in accordance with some embodiments of the present disclosure; and

FIGURE 5 illustrates a flow chart of another example method for monitoring drilling conditions associated with a drilling system in accordance with some embodiments of the present disclosure.

DETAILED DESCRIPTION

Embodiments of the present disclosure are best understood by referring to FIGURES 1 through 5, where like numbers are used to indicate like and corresponding parts.

FIGURE 1 illustrates an example embodiment of a drilling system configured to perform closed annulus drilling operations, in accordance with some embodiments of the present disclosure. During closed annulus drilling operations, some of which may be referred to as MPD, underbalanced drilling, mud cap drilling, air drilling and mist drilling, the annulus of the drill string is closed off using a device referred to as a rotating control device (RCD), a rotating drilling device, a rotating drilling head, a rotating flow diverter, pressure control device or a rotating annular. The principle sealing mechanism

of the RCD, referred to as a seal element or packer, seals around the drill string, thus, closing the annulus around the drill string. During drilling operations, various drilling conditions may affect the condition and performance of the RCD.

As disclosed in further detail below and according to some embodiments of the present disclosure, different types of sensors may be located in or near the RCD in order to measure drilling conditions associated with the RCD. The sensors may measure various properties associated with the operation, maintenance, and/or status of a drilling system (e.g. temperature, pressure, flow rate). For example, the sensors may be temperature and/or pressure transducers, flow meters, thermocouples, proximity sensors (e.g., acoustic, magnetic, laser, etc.), distance sensors, mechanical sensors (e.g., roller, arm, etc. contacting the drill string), accelerometers and/or strain gauges. These sensors may be used to measure (i) pressure in the standpipe, (ii) pressure and/or temperature associated with the seal element (e.g., upstream of the choke or RCD body), (iii) pressure, temperature, flow rate, revolutions per minute (RPM) and/or vibration associated with the bearing assembly of the RCD, (iv) pressure, flow rate and location associated with the latch assembly and (v) stripping rate, rate of penetration (ROP) and joint count associated with the tool joints of the drill string. Examples of the sensors used in drilling system 100 in accordance with the present disclosure and the measurements provided by those sensors may also be found in Table A. The measurements and/or data generated from these sensors may then be analyzed and used to take various actions during drilling operations in order to provide increased safety, reliability and/or usability of the RCD. Examples of how they may be analyzed and the actions that may be taken based on the measurements provided by the sensors may also be found in Table B.

As illustrated in FIGURE 1, drilling system 100 may include drilling unit 102, drill string 104, rotating control device (RCD) 106, sliding joint 108 and riser assembly 110. In the illustrated embodiment, drill string 104 may extend from drilling unit 102 through riser assembly 110 and into a subsea wellbore (not expressly shown) formed in the ocean floor. An upper portion of RCD 106 may be coupled to drilling unit 102 by an above RCD riser, tie back riser or telescoping joint, where the upper end of the riser or joint may be coupled to a drilling unit diverter housing (not expressly shown). A seal element or packer (not expressly shown) may be located within the body of RCD 106 and may be removed or inserted with the aid of latch assembly 103 integral, either internally or externally, to RCD 106. In some embodiments, latch assembly 103 may include a

hydraulic clamp that can be remotely controlled from drilling unit 102. A lower portion of RCD 106 may be coupled to sliding joint 108. In one embodiment, sliding joint 108 may be a telescoping joint that includes an inner barrel and an outer barrel that move relative to each other in order to allow drilling unit 102 to move during drilling operations without breaking drill string 104 and/or riser assembly 110. In other embodiments, sliding joint 108 may be a multi-part sliding joint. Sliding joint 108 may be coupled to riser assembly 110, which provides a temporary extension of a subsea wellbore (not expressly shown) to drilling unit 102.

Drilling unit 102 may be any type of drilling system configured to perform drilling operations. Although FIGURE 1 illustrates the use of RCD 106 from a floating drilling unit, those skilled in the art will understand that RCD 106 can be deployed from any type of onshore or offshore drilling unit including, but not limited to, Semi Submersible, Drill Ship, Jack Up, Production Platform, Tension Leg Platform and Land Drilling units. In some embodiments, including, but not limited to, Land Drilling units and Jack Up drilling units, a surface blow out preventer (BOP) stack may be incorporated into the drilling system. In these embodiments, RCD 106 may be coupled to a drilling annular incorporated in the BOP stack, an operations annular added to the BOP stack and drilling annular, or directly coupled to the BOP stack. In other embodiments, RCD 106 may be coupled directly to a wellhead or casing head for drilling operations prior to the BOP stack being installed.

Drilling unit 102 may include rig floor 112 that is supported by several support structures (not expressly shown). Rotary table 114 may be located above rig floor 112 and may be coupled to drill string 104 in order to facilitate the drilling of a wellbore using a drill bit (not expressly shown) coupled to the opposite end of drill string 104. Drill string 104 may include several sections of drill pipe that communicate drilling fluid from drilling unit 102 and provide torque to the drill bit. Drill string 104 may be coupled to standpipe 118 via kelly hose 120, both of which may facilitate the flow of drilling fluid into drill string 104. In some embodiments, standpipe 118 may be a thick metal tubing that is situated vertically along the derrick of drilling system 100 and is attached to and supports one end of kelly hose 120. Standpipe 118 is further coupled to pump 122 that is used to circulate drilling fluid from tank 124. In the illustrated embodiment, the drilling fluid may be circulated back to drilling unit 102 through riser assembly 110. In other embodiments, such as a land drilling unit, the drilling fluid may be circulated through the

wellbore or a casing included in the wellbore. Additionally, various cables 116 may couple RCD 106, slip joint 108 and riser assembly 110 to equipment on drilling unit 102.

A sensor (not expressly shown) may be located in standpipe 118 to measure the pressure in standpipe 118. In one embodiment, the sensor may be a pressure transducer. In other embodiments, a sensor may be a part of a measurement while drilling (MWD) system such that the pressure in standpipe 118 may be derived from software associated with the MWD system. For example, a MWD system may be deposited near a drill bit in the wellbore and may measure various properties related to drilling system 100. The pressure in standpipe 118 may indicate whether drilling fluid is being circulated through drill string 104 or if washout or plugging is occurring. For example, a detected pressure greater than a predetermined threshold or a constant pressure over time may indicate that drilling system 100 is operating normally and drilling fluid is being circulated through drill string 104. A detected pressure less than a predetermined threshold or a loss in pressure over time may indicate that a washout has occurred in drill string 104 or that drill string 104 is plugged. If the detected pressure indicates that a washout has occurred or drill string 104 is plugged, an alarm may be generated by a control system (e.g., the control system as illustrated in FIGURE 3) to alert an operator of drilling system 100.

FIGURE 2 illustrates a partial cross-sectional view of RCD 106 including one or more sensors 212 associated with various parts of RCD 106 in accordance with some embodiments of the present disclosure. RCD 106 may be used to seal annulus 202 formed radially between body 204 of RCD 106 and drill string 104 positioned within body 204. RCD 106 may allow drill string 104 to rotate and enter and exit the wellbore while maintaining pressure in annulus 202. In the illustrated embodiment, bearing assembly 206 may be located in bearing assembly housing 208. One or more seal elements 210 (for example, upper seal element 210A and lower seal element 210B) may be coupled to body 204 of RCD 106 by a mandrel (not expressly shown) connected to bearing assembly 206 such that seal element 210 may rotate with drill string 104. Bearing assembly 206 may facilitate the movement of drill string 104 relative to body 204. In other embodiments, RCD 106 may not include bearing assembly 206 such that seal element 210 remains stationary while drill string 104 rotates within RCD 106. Latch assembly 103 may be used to secure and release bearing assembly 206 and seal element 210 relative to body 204.

Seal element 210 may form a seal around drill string 104 to close annulus 202 and maintain pressure in annulus 202 during drilling operations. In some embodiments, seal element 210 may be a molded device made of an elastomeric material. The elastomeric material may be compounds including, but not limited to, natural rubber, nitrile rubber, hydrogenated nitrile, urethane, polyurethane, fluorocarbon, perflurocarbon, propylene, neoprene, hydrin, etc. Sensors 212 may be associated with seal element 210 in order to detect various drilling conditions during drilling operations. For example, sensors 212 may be located in body 204 of RCD 106 below bearing assembly 206 and may be configured to detect the pressure and/or temperature associated with seal element 210. Sensors 212 may be pressure or temperature transducers or combination sensors configured to detect both pressure and temperature. In some embodiments, the pressure and/or temperature of seal element 210 may additionally be measured by sensors located upstream of a choke (not expressly shown) associated with RCD 106. In some embodiments, sensors 212 may be located within seal element 210.

Sensors 212 may also be associated with bearing assembly 206 and configured to measure certain drilling conditions associated with bearing assembly 206. For example, sensors 212 may be located in the cavity of bearing assembly 206, on the mandrel coupling seal element 210 to bearing assembly 206, in the seal pressure stages (not expressly shown) of RCD 106, in the cooling circuits (not expressly shown) of RCD 106 and/or in the incoming and return lines (not expressly shown) associated with RCD 106. In some embodiments, sensors 212 associated with bearing assembly 206 may be configured to measure the pressure and/or temperature associated with bearing assembly 206 or between elements (e.g., the upper stripper and mandrel) in RCD 106. The pressure and/or temperature sensors may be pressure or temperature transducers, thermocouples for measuring temperature or combination sensors configured to measure both pressure and temperature. In other embodiments, sensors 212 associated with bearing assembly 206 may be flow meters configured to measure flow rates of fluids in bearing assembly 206. In further embodiments, sensors 212 associated with bearing assembly 206 may be proximity sensors located on fixed and rotating members of bearing assembly 206. Signals from the proximity sensors may be used to calculate the revolutions per minute (RPM) of bearing assembly 206 and/or drill string 104. In additional embodiments, sensors 212 associated with bearing assembly 206 may be accelerometers and/or acoustic sensors configured to detect vibration associated with bearing assembly 206 and/or the

associated mandrel. In other embodiments, sensors 212 associated with bearing assembly 206 may be strain gauges located on the mandrel and used to determine the torque imparted by a drill pipe/tool joint interface on drill string 104 to bearing assembly 206.

Sensors 212 may also be located inside the mandrel of bearing assembly 206, the upper stripper (not expressly shown) of RCD 106, body 204 of RCD 106, and/or the tieback (not expressly shown) of RCD 106 to determine various drilling conditions associated with tool joints 214 of drill string 104. For example, sensors 212 may be casing collar locators (CCL), proximity sensors (e.g., acoustic, magnetic, laser, etc.), distance sensors and/or mechanical sensors (e.g., a roller or arm contacting drill string 104) configured to sense each time tool joint 214 passes through RCD 106. In some embodiments, the signals from sensors 212 may be used to calculate the stripping rate or rate of penetration for tool joint 214.

Sensors 212 may further be associated with latch assembly 103 in order to determine the status of latch engagement. For example, sensor 212 may be a flow meter located in a hydraulic circuit (not expressly shown) of latch assembly 103 to determine the position and engagement of latch assembly 103 based on total flow. In other embodiments, sensor 212 may be a pressure transducer located in the hydraulic circuit of latch assembly 103 to determine the pressure in latch assembly 103. In further embodiments, sensor 212 may be a proximity sensor (e.g., acoustic, magnetic, laser, etc.), a distance sensor, and/or a mechanical sensor configured to sense the location of the latch member or piston (not expressly shown) in latch assembly 103.

Sensors 212 may communicate the measured drilling conditions to a control system (such as the control system illustrated in FIGURE 3) located on or remote from drilling unit 102 (as illustrated in FIGURE 1). As described in more detail in reference to FIGURE 3, the control system may correlate the drilling condition data to various actions that should be taken during drilling operations, for example, such that a drilling operator can make a determination of when to replace seal element 210 and/or the bearings of bearing assembly 206.

Although FIGURE 2 illustrates a particular number and location for sensors 212, any number of sensors may be located in various positions in RCD 106. Additionally, although certain types of sensors and the measurements provided by the sensors are described in reference to FIGURE 2, other sensors and measurements may be provided as described in Tables A and B.

FIGURE 3 illustrates a block diagram of a control system configured to receive measurements from the sensors associated with the standpipe of FIGURE 1 and the rotating control device of FIGURE 2 in accordance with some embodiments of the present disclosure. In some embodiments, one or more sensors 212a-212i may be associated with drilling system 100 and configured to measure any number of drilling conditions associated with RCD 106. As described above and in Table A, sensors 212 may be temperature and/or pressure transducers, flow meters, thermocouples, proximity sensors (e.g., acoustic, magnetic, laser, etc.), distance sensors, mechanical sensors (e.g., roller, arm, etc. contacting the drill string), accelerometers and/or strain gauges. To the extent any of sensors 212 require power to operate, sensors 212 may be powered by battery power, wired power, solar power, or any other power source as may be appropriate for the location and power demands of sensor 212.

Sensors 212 may be communicatively coupled to input device 302 of control system 300 such that control system 300 may receive the drilling condition data and other information measured by sensors 212. Input device 302 may direct the data received from sensors 212 to processing system 304. Input device 302 may also be communicatively coupled to other sources of information about drilling system 100 generally, for example, measurement while drilling (MWD) system 320. Processing system 304 may include a processor 312 coupled to a memory 314. Processor 312 may include, for example, a microprocessor, microcontroller, digital signal processor (DSP), application specific integrated circuit (ASIC), or any other digital or analog circuitry configured to interpret and/or execute program instructions and/or process data. In some embodiments, processor 312 may interpret and/or execute program instructions and/or process data stored in memory 314. Such program instructions or process data may constitute portions of software for carrying out simulation, monitoring, or control of drilling operations. Memory 314 may include any system, device, or apparatus configured to hold and/or house one or more memory modules; for example, memory 314 may include read-only memory, random access memory, solid state memory, or disk-based memory. Each memory module may include any system, device or apparatus configured to retain program instructions and/or data for a period of time (e.g., computer-readable non-transitory media). For the purposes of this disclosure, computer-readable media may include any instrumentality or aggregation of instrumentalities that may retain data and/or instructions for a period of time. Computer-readable media may include,

without limitation, storage media such as a direct access storage device (e.g., a hard disk drive or floppy disk), a sequential access storage device (e.g., a tape disk drive), compact disk, CD-ROM, DVD, random access memory (RAM), read-only memory (ROM), electrically erasable programmable read-only memory (EEPROM), and/or flash memory; as well as communications media such as wires, optical fibers, and other electromagnetic and/or optical carriers; and/or any combination of the foregoing.

Processing system 304 may also be coupled to a storage device 316. Storage device 316 may include any instrumentality or aggregation of instrumentalities that may retain data and/or instructions for a period of time. Storage device 316 may include, without limitation, storage media such as a direct access storage device (e.g., a hard disk drive, optical drive, solid state drive, or floppy disk), a sequential access storage device (e.g., a tape disk drive), compact disk, CD-ROM, DVD, random access memory (RAM), read-only memory (ROM), electrically erasable programmable read-only memory (EEPROM), and/or flash memory, or any combinations thereof. In some embodiments, storage device 316 may store any of the information handled, processed, reported, produced, or utilized by processing system 304.

In some embodiments, sensors 212 may be communicatively coupled to input device 302 indirectly through a transmitter and/or receiver (not shown). Transmitters and/or receivers may be placed at a variety of locations throughout a drilling system (e.g. drilling system 100 illustrated in FIGURE 1). For example, transmitters and/or receivers may be placed in proximity to (i) body 204, bearing assembly 206, tie back, and/or upper stripper of RCD 106, (ii) the hydraulic power unit (HPU), (iii) the work platform, the control console, and/or the rig floor or cantilever deck of the drilling unit (such as drilling unit 102 of FIGURE 1), and/or (iv) near the wellhead (e.g. on a BOP stack). In other embodiments, data from sensors 212 may be communicated through wires, such as electrical wires or fiber optics. In additional embodiments, communication of the drilling conditions from sensors 212 may be wireless. For example, the signals carrying the drilling conditions may be acoustic, electromagnetic or optical. The signals carrying drilling conditions may also be transmitted via fluid pulse. The measurements may be communicated by sensors 212 either continuously or based on a pre-determined time interval.

Processing system 304 may be communicatively coupled to display 306 that is part of control system 300 such that information processed by processing system 304 may

be conveyed to operators of a drilling system (e.g., drilling system 100 as illustrated in FIGURE 1). Display 306 may display various drilling conditions obtained by sensors 212 and/or values calculated by processing system 304. Printer 308 and associated printouts 308a may also be used to report the drilling conditions associated with RCD 106. Outputs 310 may be communicated to various components associated with operating the associated drilling system, to various remote locations to monitor and/or control the performance of the drilling system, or to users simulating the drilling of a wellbore. Outputs 310 may also be communicated to various data storage locations (not expressly shown), either local to the drilling system or remotely, for example, to a facility including various data storage devices.

In some embodiments, in addition to various drilling conditions and/or values calculated based on drilling conditions, other information regarding a drilling system (e.g., drilling system 100 as illustrated in FIGURE 1) may be displayed on display 306. Display 306 may display the status of a latch assembly (e.g., latch assembly 103 as illustrated in FIGURE 1) as a total flow in a hydraulic circuit associated with the latch assembly and the total flow required for engagement of the latch assembly, a graphic of the position of the piston of the latch assembly and/or the latch assembly, a percentage of actuation of the latch assembly, and/or a Boolean value (e.g. "latched" or "unlatched"). Display 306 may also display status of a cooling system associated with an RCD (e.g., RCD 106 as illustrated in FIGURES 1 and 2). For example, display 306 may display the temperature of a tank of the cooling system, the temperature of outgoing lines, the temperature of the fluid in return lines, flow rates of the cooling fluid, whether the cooler fan is on or off, and whether a pump of the cooling system is on or off. Display 306 may also display status of a lubrication system associated with the RCD. For example, display 306 may display a pressure set point and a graph over time of the pressure of the lubrication system and/or the wellbore over time. As another example, display 306 may also display an average and/or instantaneous flow rate of fluid in a lubrication system, a total flow for a given time period, and/or time until a tank of the lubrication system is empty. Display 306 may also display parameters associated with the RCD, for example, temperature in a bearing assembly (e.g. bearing assembly 206 as illustrated in FIGURE 2), pressure in the bearing assembly, and/or pressure between elements (e.g. an upper stripper and a mandrel of the RCD). Display 306 may additionally display parameters associated with general operation of the drilling system, for example, number of hours in

the hole (static and/or rotating), number of tool joints passed down hole, wellbore annulus pressure, and/or temperature of wellbore fluid. It will be appreciated that display 306 may display any combination of the foregoing, either simultaneously or separately in any variation of combinations. For example and in no way limiting, display 306 may display all relevant information regarding the RCD at once, and then may separately (for example by a menu selection of control system 300) display information regarding the cooling and lubrication systems together.

In some embodiments, control system 300 may be configured to receive drilling conditions associated with standpipe 118 and RCD 106 from sensors 212 during drilling operations. Processing system 304 may interpret the drilling condition data and determine actions to be taken during drilling operations. For example, the signals from sensors 212 may be processed based on scalar functions and/or algorithms used to calculate various drilling parameters. In some embodiments, temperature, pressure, flow rate, vibration, latch position, torque, and/or any combination thereof may be processed based on a scalar function. The drilling conditions received may include, but are not limited to, pressure, temperature, flow rate, vibration, position, torque, strain and tool joint count as described in Table A. Once the measured drilling conditions are processed into a useable format, processing system 304 may analyze the drilling condition data and determine an adjustment to one or more drilling parameters based on the analyzed data that may be made manually by an operator of drilling system 100 and/or automatically by processing system 304.

In one embodiment, processing system 304 may analyze the received drilling condition data by comparing the data to corresponding pre-determined thresholds or trigger points in order to interpret the data and make a determination of what actions should be taken during drilling operations. In other embodiments, processing system 304 may compare a change in drilling conditions over time to corresponding pre-determined thresholds or trigger points. In further embodiments, processing system 304 may use the detected drilling conditions to calculate a drilling parameter (e.g. through the use of an algorithm). For example, processing system 304 may use position data from proximity sensors to calculate revolutions per minute (RPM) of bearing assembly 206 and/or drill string 104 and tool joint stripping rate or rate of penetration (ROP) using an algorithm. Other examples of calculations that may be performed by processing system 304 based on the analyzed data are described in Table B. In some embodiments, an alarm may be

generated by processing system 304 if a drilling condition or other determined value exceeds a pre-determined threshold or trigger point. For some drilling conditions or other determined values, an alarm may only be generated if the drilling condition or other determined value exceeds the pre-determined threshold or trigger point for a specified duration of time. In some embodiments, multiple trigger points generating multiple alarms may be associated with a single drilling condition or other determined value. For example, if the trigger point is passed by a first amount, a first alarm may be generated and if the trigger point is passed be a second further amount, a second more severe alarm may be generated.

Processing system 304 may interpret data associated with standpipe 118 of drilling system 100 as described in Table B. In this embodiment, sensor 212 may be a pressure transducer configured to measure the pressure in standpipe 118. The pressure in standpipe 118 may be an indication of whether the drilling fluid is circulating through drill string 104 or whether a washout has occurred in drill string 104 or drilling string 104 is plugged. If the measured pressure is greater than a pre-determined threshold or the pressure is constant, processing system 304 may determine that drilling fluid is circulating normally through drill string 104. If the measured pressure is less than a pre-determined threshold or the pressure decreased over time, processing system 304 may determine that a washout has occurred or drill string 104 is plugged and generate an alarm that may be displayed on display 306.

Processing system 304 may also interpret data associated with seal element 210 of RCD 106 as described in Table B. In this embodiment, sensor 212 may be a pressure or temperature transducer, a thermocouple, and/or a combination sensor configured to measure both pressure and temperature. The pressure below seal element 210 may be an indication of whether it is safe to unlatch RCD 106. For example, if the measured pressure is approximately equal to zero pounds per square inch (psi), latch assembly 103 of RCD 106 may be safe to unlock and, if the measured pressure is greater than zero psi, latch assembly 103 of RCD 106 should remain locked. Additionally, the pressure below seal element 210 may indicate what pressure should be applied to the lubrication system associated with RCD 106 and what pressure should be applied to an active element of RCD 106. The amount of pressure that should be applied to the lubrication system or the active element may be used as an input value to a formula used to calculate the pressures.

The temperature below seal element 210 may provide an indication of the heat load that is being cooled by the cooling circuit of RCD 106 and may indicate whether the temperature limits for the materials used for the various elements in RCD 106 have been exceeded. For example, if the measured temperature is greater than a pre-determined threshold, the cooling fluid flow rate may be changed by, for example, opening or closing the cooling loops in the cooling circuitry of RCD 106 in order to reduce the temperature. In other embodiments, the coolant fluid coolers and/or chillers in drilling system 100 may be activated or deactivated as appropriate.

Processing system 304 may additionally interpret data associated with bearing assembly 206 of RCD 106 as described in Table B. In this embodiment, sensor 212 may be a pressure or temperature transducer, a thermocouple for measuring temperature, a combination sensor configured to measure both pressure and temperature, a flow meter, a proximity sensor (e.g., acoustic, magnetic, laser, etc.), a distance sensor, a mechanical sensor (e.g., roller, arm, etc. contacting drill string), an accelerometers and/or a strain gauge. In one embodiment, sensor 212 may measure the pressure(s) in bearing assembly 206. The pressure in bearing assembly 206 may indicate whether the static seals and other components of the lubrication circuit are functioning properly, provide an indication of the lifetime of bearings in bearing assembly 206 and indicate a status of the engagement of latch assembly 103. For example, the detected pressure may indicate the status of a lubrication circuit in bearing assembly 206. If the pressure cannot be maintained at a set point, processing system 304 may activate an alarm that is displayed on display 306 to alert the operator of drilling system 100.

In another embodiment, sensor 212 may measure the temperature in bearing assembly 206. The temperature in bearing assembly 206 may provide an indication of whether the temperature limits for the materials associated with, for example, seal element 210, are being exceeded. If the measured temperature is outside of a specified range, processing system 304 may activate an alarm to alert an operator of drilling system 100 that the temperature inside bearing assembly 206 is greater than a pre-determined threshold. The measured temperature associated with bearing assembly 206 may also be combined with other sensor measurements as described in Table B. As one example, processing system 304 may use the temperature and the pressure associated with bearing assembly 206 to calculate the estimated lifetime of bearings in bearing assembly 206. If the estimated lifetime is less than a minimum value, processing system 304 may generate

an alarm that may be displayed on display 306 and alerts an operator of drilling system 100 that the bearings in bearing assembly 206 may have reached their maximum life and should be replaced. Other example adjustments based on the measured pressure and/or temperature are described in Table B.

In a further embodiment, sensor 212 may measure the flow rate of bearing assembly fluids in bearing assembly 206. The flow rate of the fluids may indicate if various components of RCD 106 are working properly and/or if seal element 210 is worn. The flow rates may additionally be used to calculate the heat that is being transferred to the cooling circuit of RCD 106 during drilling. For example, processing system 304 may compare the measured flow rates with pre-determined flow rates that are expected under certain conditions. If the flow rates are not within a specified range during a certain time, processing system 304 may generate an alarm to allow an operator of drilling system 100 to adjust any pumps and/or valves associated with bearing assembly 206 to achieve the set points. In other embodiments, processing system 206 may generate outputs 310 to drilling system 100 so that the pumps and/or valves may be automatically adjusted. Other example adjustments based on the measured flow rates are described in Table B.

In an additional embodiment, sensor 212 associated with bearing assembly 206 may be a proximity sensor (e.g., acoustic, magnetic, laser, etc.), a distance sensor and/or a mechanical sensor (e.g., roller, arm, etc. contacting drill string). The measurements provided by these types of sensors may provide a count of the number of tool joints 214 that pass through RCD 106 during drilling operations and may be used to calculate the revolutions per minute (RPM) of bearing assembly 206 and/or the RPM of drill string 104. The tool joint count and RPM values may be used to estimate the lifetime of seal element 210 and/or bearing assembly 206. Additionally, the RPM of bearing assembly 206 combined with the RPM of drill string 104 may indicate element slippage and whether certain elements, such as seal element 210, are worn. Processing system 304 may compare the bearing assembly RPM to the drill string RPM. If the difference between these values is greater than a pre-determined threshold for a specified time period, processing system 304 may generate an alarm for display on display 306. Other example adjustments based on the measurements provided by proximity sensors, distance sensors and/or mechanical sensors are described in Table B.

In another embodiment, sensor 212 associated with bearing assembly 206 may be an accelerometer configured to detect vibration associated with bearing assembly 206.

Vibration in bearing assembly 206 may indicate metal to metal contact between rotating and stationary components and may be used to estimate the lifetime of bearing assembly 206 and/or seal element 210. Processing system 304 may compare the measured vibration with a pre-determined threshold and may generate an alarm to alert an operator of processing system 100 if the pre-determined threshold is exceeded for a specified time period. Other example adjustments based on the measurements provided by accelerometers are described in Table B.

In a further embodiment, sensor 212 associated with bearing assembly 206 may be a strain gauge configured to determine the torque imparted by a drill pipe/tool joint interface on drill string 104 to bearing assembly 206. The measured torque may indicate whether the bearings in bearing assembly 206 and/or seal element 210 are failing or worn and may be compared with a pre-determined value to determine element slippage. If the measured torque is greater than a pre-determined threshold, processing system 304 may generate an alarm for display on display 306. Other example adjustments based on the measurements provided by strain gauges are described in Table B.

The drilling conditions measured by sensors 212 and actions taken by processing system 304 that are described with respect to FIGURE 3 are merely exemplary of the drilling conditions that may be analyzed by processing system 304. Additional drilling conditions associated with RCD 106 may be analyzed and processing system 304 may determine further actions to take during drilling operations based on the analyzed data as further described in Table B. Additionally, processing system 304 may analyze multiple drilling conditions and make a determination based on the combined data as further described in Table B. Modifications, additions, or omissions may also be made to FIGURE 3 without departing from the scope of the present disclosure. For example, the number and type of sensors 212 may vary depending on the drilling application.

In some embodiments, the operator may take an action based on the alarm and/or processing system 304 may automatically take the action by adjusting one or more drilling parameters. The operator may independently take actions that may affect the drilling conditions, determinations based on the drilling conditions, and/or automated actions based on the drilling conditions. In some embodiments, these actions may be done to override a feature or recommended action of control system 300 and in some embodiments may be taken by interacting with control system 300. For example, an operator may perform one of the following actions: turn drilling system 100 on or off

with actuation of a button, manually turn off a safety feature like a pressure lock for latch assembly 103, manually open or close latch assembly 103, adjust a lubrication system pressure set point from a default value, set different parameters of drilling conditions for rig up, normal operation, and/or rig down profiles (e.g. increased rates of change for pressure and temperature may be permissible during rig up and rig down when compared to normal operation), adjust a temperature set point from a default value affecting cooler fans turning on or off and/or heaters turning on or off, manually open or close valves, manually turn pumps on or off, reset tool joint 214 stripping count, reset a count of hours in hole (both static and/or rotating), manually turn on or off a heater, manually turn on or off a cooler fan, and/or reset a total flow count for a flow meter or a pump-stroke counter.

Control system 300 may store any or all of the data received or processed at control system 300, for example, in storage device 316, and may include time stamps of when data was received and/or processed. For example, control system 300 may store any of the calculated drilling conditions, calculations, and/or actions described in Tables A and B. Operator input to control system 300 may also be stored. For example, an operator of the drilling system may enter a well and/or job name, start and end date and time, field hand name, operator comments, and/or operator compliance with procedure-based task lists to bring a drilling system up, operate a drilling system, and/or bring a drilling system down. Control system 300 may also store independently taken operator actions that may affect the drilling conditions, determinations based on the drilling conditions, and/or automated actions based on the drilling conditions, and may include a time stamp of when the action was taken. Control system 300 may cause the storing to occur locally in storage device 316 or remotely (for example, transmitting data via wired or wireless connection to a data storage facility). In some embodiments, a data retention scheme may be in place to retain at least a portion of stored data for at least the length of a particular drilling operation involving the drilling system. In some embodiments, some data may be preferentially stored over other data, for example and in no way limiting, triggered alarms and operator input may be stored indefinitely while other data may be periodically deleted from storage. It will be appreciated that any of a variety of data retention schemes may be used in accordance with the present disclosure.

Table A illustrates example drilling conditions that may be monitored, example locations for the sensors within the drilling system or example sources where information regarding the drilling condition may be received, and example sensors that may be used

to measure the drilling conditions. It will be appreciated that the entries in Table A are merely exemplary of the drilling conditions that may be measured, locations for the sensors within drilling system and types of sensors that may be used, and are in no way limiting. While some of the entries in Table A may be expressed with reference to FIGURES 1-3, it will be appreciated that the entries are merely illustrative and are in no way limiting. In addition, it will be appreciated that in addition to a single entry for a given drilling condition, any combination of entries from Table A may be utilized, including multiple entries for a single row. For example, in considering pressure in bearing assembly 206, there may be a pressure transducer in the main cavity of bearing assembly 206, a combination pressure/temperature sensor in the seal pressure stage, and a pressure transducer in the cooling circuit, the combination of which may facilitate the monitoring and/or measuring of pressure in bearing assembly 206. It will also be appreciated that a single sensor may measure multiple drilling conditions.

Table A

Drilling Condition	**Location and Type of Sensor or Source of Information**
standpipe 118 pressure	-pressure transducer within standpipe 118 -MWD software reporting previously sensed pressure
pressure of fluid in annulus 202 below seal element 210B	-pressure transducer or combination sensor (e.g. pressure/temperature sensor) in body 204 of RCD 106 below bearing assembly 206 -pressure transducer or combination sensor (e.g. pressure/temperature sensor) upstream of a choke in annulus 202
temperature of fluid in annulus 202 below seal element 210B	-temperature transducer or combination sensor (e.g. pressure/temperature sensor) in body 204 of RCD 106 below bearing assembly 206 -temperature transducer or combination sensor (e.g. pressure/temperature sensor) upstream of a choke in annulus 202
pressure in bearing assembly 206	-pressure transducer or combination sensor (e.g. pressure/temperature sensor) in main cavity of bearing assembly 206 -pressure transducer or combination sensor (e.g. pressure/temperature sensor) between seal elements (e.g. rotary seals) where pressure may differ from wellbore pressure and may also differ from the pressure in the main cavity of bearing assembly 206 -pressure transducer or combination sensor (e.g.

Drilling Condition	Location and Type of Sensor or Source of Information
	pressure/temperature sensor) in cooling circuit associated with bearing assembly 206 -pressure transducer or combination sensor (e.g. pressure/temperature sensor) in incoming or return lines for drilling fluid
flow rate in bearing assembly 206 fluids	-flow meter in main cavity of bearing assembly 206 -flow meter in seal pressure stage -flow meter in cooling circuit -flow meter in lubrication circuit
temperature in bearing assembly 206	-temperature transducer or combination sensor (e.g. pressure/temperature sensor) in main cavity of bearing assembly 206 -temperature transducer or combination sensor (e.g. pressure/temperature sensor) in seal pressure stage -temperature transducer or combination sensor (e.g. pressure/temperature sensor) in cooling circuit -temperature transducer or combination sensor (e.g. pressure/temperature sensor) in incoming or return lines for drilling fluid
revolutions per minute (RPM) of bearing assembly 206	-proximity sensor on fixed members of bearing assembly 206 -proximity sensor on rotating members of bearing assembly 206 -mechanical sensor on roller contacting bearing assembly 206 -mechanical sensor on arm contacting bearing assembly 206 -tachometer or encoder on rotating members of bearing assembly 206
RPM of drill string 104	-mechanical sensor on roller contacting drill string 104 -mechanical sensor on arm contacting drill string 104 -drilling system 100 previously sensed value -manual entry of RPM value by an operator of drilling system 100
pressure between elements (e.g. upper stripper and mandrel of RCD 106)	-pressure transducer or combination sensor (e.g. pressure/temperature sensor) in upper stripper -pressure transducer or combination sensor (e.g. pressure/temperature sensor) in mandrel

Drilling Condition	Location and Type of Sensor or Source of Information
	-pressure transducer or combination sensor (e.g. pressure/temperature sensor) in other elements
tool joint 214 count	-Casing Collar Locator (CCL) inside mandrel -CCL inside upper stripper -CCL inside body 204 -CCL inside tieback -proximity sensor inside mandrel -proximity sensor inside upper stripper -proximity sensor inside body 204 -proximity sensor inside tieback -distance sensor associated with mandrel -distance sensor associated with upper stripper -distance sensor associated with body 204 -distance sensor associated with upper tieback -mechanical sensor on roller contacting drill string 104 -mechanical sensor on arm contacting drill string 104
tool joint 214 stripping rate/rate of penetration	-CCL inside mandrel -CCL inside upper stripper -CCL inside body 204 -CCL inside tieback -proximity sensor inside mandrel -proximity sensor inside upper stripper -proximity sensor inside body 204 -proximity sensor inside tieback -distance sensor associated with mandrel -distance sensor associated with upper stripper -distance sensor associated with body 204 -distance sensor associated with upper tieback -mechanical sensor on roller contacting drill string 104 -mechanical sensor on arm contacting drill string 104
vibration of bearing assembly 206	-accelerometer on mandrel -accelerometer on housing of bearing assembly 206 -proximity sensor on mandrel

Drilling Condition	Location and Type of Sensor or Source of Information
	-proximity sensor on housing of bearing assembly 206
torque imparted from drill string 104 and/or tool joint 214 to mandrel and/or bearing assembly 206	-strain gauge on mandrel -strain gauge inside seal element/packer
latch assembly 103 engagement	-flow meter in hydraulic circuit -pressure transducer or combination sensor (e.g. pressure/temperature sensor) in hydraulic circuit -proximity sensor in latch assembly 103 -distance sensor in latch assembly 103 -mechanical sensor on roller contacting latch assembly 103 -mechanical sensor on arm contacting latch assembly 103

Table B illustrates example interpretations of drilling conditions (for example, those described in Table A) from the sensors within the drilling system, example indications, parameters, or values that may be determined from the drilling conditions and/or interpretations, and example actions (either automated or operator initiated) and/or conclusions that may be suggested from the drilling conditions and/or interpretations. It will be appreciated that the entries in Table B are merely exemplary of the interpretations, indications, parameters, or values that may be based on the drilling conditions from the drilling system, and are in no way limiting. While some of the entries in Table B may be expressed with reference to FIGURES 1-3, it will be appreciated that the entries are merely illustrative and are in no way limiting. Also, it will be appreciated that in addition to a single entry, any combination of entries from Table B may be utilized, including multiple entries for a single row. For example, the temperature of fluid in annulus 202 below seal element 210 may be used to: indicate heat load to be cooled by the cooling circuit, indicate whether seal element 210 is exceeding temperature limits, modify cooling circuit flow rate, open or close additional cooling loops, activate or deactivate coolant fluid coolers and/or chillers, indicate status of acceptable operating temperature, display alarm or notification if operating temperature is exceeded, or any combination thereof.

Table B

Drilling Condition	Interpretation, Conclusions, and/or Actions Based on Drilling Conditions
standpipe 118 pressure	-indicate status, for example, whether circulation is in progress, if a connection is being made, or if a washout or plugging is occurring
pressure of fluid in annulus 202 below seal element 210B	-indicate whether it is safe to unlatch and activate interlocks (e.g. **Inventors, what all is involved in activating the interlocks** -when pressure is zero psi, indicate it is safe to unlatch and unlock system to allow unlatch operation -when pressure is greater than zero psi, indicate it is unsafe to unlatch and system remains locked, preventing unlatch operation (e.g. software would not allow activation/actuation of the latch controls, a pressure switch may be in a position such that power is not provided to a normally closed solenoid valve that controls hydraulic fluid flow to activate/actuate latch assembly 103 when pressure is greater than zero psi, hydraulic fluid flow may be prevented from activating/actuating latch assembly 103 and latch assembly 103 may thereby be interlocked with the presence of pressure in the annulus below the seal element) -indicates what pressure needs to be applied to an active element of RCD 106 -indicates what pressure needs to be applied to the lubrication system associated with RCD 106
temperature of fluid in annulus 202 below seal element 210	-indicate heat load to be cooled by the cooling circuit -indicate whether seal element 210 is exceeding temperature limits -modify flow rate of coolant fluid in cooling circuit -open or close additional cooling loops -activate or deactivate coolant fluid coolers and/or chillers -indicate status of acceptable operating temperature -display alarm or notification if operating temperature is exceeded
pressure in bearing assembly 206	-indicate if seals and other components of lubrication circuits are working properly -indicate status of lubrication circuits -predict lifetime of bearing assembly 206 -indicate latch assembly 103 engagement -display alarm or notification if pressure in bearing

Drilling Condition	Interpretation, Conclusions, and/or Actions Based on Drilling Conditions
	assembly 206 not maintained at set point
flow rate in bearing assembly 206 fluids	-indicate if cooling circuit components are working properly -indicate if lubrication circuit components are working properly -compare actual flow rate to set point or expected flow rates for lubrication and/or coolant fluids -regulate pumps and/or valves to achieve set point flow rates for lubrication and/or coolant fluids -display alarm or notification if flow rate of lubrication and/or coolant fluids outside of specified range for specified time limit -indicate if seal element 210 is worn based on comparison of actual flow rates of lubrication and/or coolant fluids to set point or expected flow rates -display alarm or notification if seal element 210 is worn -use to calculate heat transferred to cooling circuit -indicate heat transfer rate (duty) of cooling circuit -display alarm or notification if heat transfer rate is below estimated required value based on torque, wellbore temperature, bearing assembly 206 temperature, and inlet/outlet temperatures of cooling circuit
temperature in bearing assembly 206	-indicate if temperature limits for materials of seal element 210 or other components (e.g. o-rings) are exceeded -display alarm or notification if temperature for materials is exceeded -indicate lifetime of bearings in bearing assembly 206
tool joint 214 count	-estimate lifetime of seal element 210
tool joint 214 stripping rate/rate of penetration	-display tool joint 214 stripping rate -display alarm or notification if maximum rate is exceeded -estimate lifetime of seal element 210 -indicate number of tool joints 214 stripped through element and remaining lifetime (for example, in number of tool joints 214) -display alarm or notification if number of tool joints 214 stripped exceeds specified value (for example, an expected

Drilling Condition	Interpretation, Conclusions, and/or Actions Based on Drilling Conditions
	element lifetime) -indicate surge and swab conditions
vibration of bearing assembly 206	-estimate lifetime of bearing in bearing assembly 206 -estimate lifetime of seal element 210 -estimate other component failures (for example, a failure causing metal-to-metal contact between rotating and stationary parts generating vibration at bearing assembly 206) -indicate vibration level status based on acceptable levels -display alarm or notification if acceptable levels of vibration are exceeded for specified duration
torque imparted from drill string 104 and/or tool joint 214 to mandrel and/or bearing assembly 206	-indicate bearing in bearing assembly 206 failure -estimate lifetime of bearing in bearing assembly 206 -indicate seal element 210 failure -estimate lifetime of seal element 210 -indicate element slippage or wear -display alarm or notification if specified maximum value is exceeded
latch assembly 103 engagement	-flow meter in hydraulic circuit -estimate piston position based on amount of fluid flow through hydraulic circuit -indicate piston/latch assembly 103 position -activate appropriate control profile based on position of piston/latch assembly 103 (for example, if in an "unlatching/unlatched" position, the cooling circuit, active element, and lubrication circuit may be disabled from allowing fluid to flow to RCD 106; if in "latched/normal operation" position, the cooling circuit, active element, and lubrication circuit may be enabled to allow fluid to flow to RCD 106) -pressure transducer or combination sensor (for example, pressure/temperature sensor) in hydraulic circuit -indicate bearing assembly 206 is landing in body 204 based on initial pressure spike -indicate latch assembly 103 engagement when increased pressure holds -activate appropriate control profile based on estimated

Drilling Condition	Interpretation, Conclusions, and/or Actions Based on Drilling Conditions
	location of latch assembly 103 (for example, if latch assembly 103 is not engaged, then in an "unlatching/unlatched" position and the cooling circuit, active element, and lubrication circuit may be disabled from allowing fluid to flow to RCD 106; if latch assembly 103 is engaged, then in a "latched/normal operation" position and the cooling circuit, active element, and lubrication circuit may be enabled to allow fluid to flow to RCD 106) -proximity sensor in latch assembly 103, distance sensor in latch assembly 103, mechanical sensor on roller contacting latch assembly 103, and/or mechanical sensor on arm contacting latch assembly 103 -indicate piston/latch assembly 103 position -activate appropriate control profile based on position of piston/latch assembly 103 (for example, if in an "unlatching/unlatched" position, the cooling circuit, active element, and lubrication circuit may be disabled from allowing fluid to flow to RCD 106; if in a "latched/normal operation" position, the cooling circuit, active element, and lubrication circuit may be enabled to allow fluid to flow to RCD 106)
combination of pressure between elements (e.g. upper stripper and mandrel of RCD 106), pressure of fluid in annulus 202 below seal element 210B, and tool joint 214 location	-indicate seal element 210 failure if pressure between elements (e.g. upper stripper and mandrel of RCD 106) increases when tool joint 214 is not in proximity of the mandrel -indicate status of seal element 210 -display alarm or notification if seal element 210 fails
combination of temperature of fluid in annulus 202 below seal element 210B and temperature inside bearing assembly 206	-indicate effectiveness of cooling circuit -modify flow rate of coolant fluid in cooling circuit -open or close additional cooling loops -activate or deactivate coolant fluid coolers and/or chillers
combination of pressure in bearing assembly 206 and temperature in bearing assembly 206	-predict lifetime of bearing assembly 206 -indicate estimated remaining lifetime of bearing assembly 206 -display alarm or notification if bearing assembly 206 lifetime reaches minimum value

Drilling Condition	Interpretation, Conclusions, and/or Actions Based on Drilling Conditions
	-calculate upper seal element 210A leakage rate -indicate upper seal element 210A leakage -display alarm or notification if upper seal element 210A leakage rate exceeds set point
combination of pressure in bearing assembly 206, temperature in bearing assembly 206, and pressure of fluid in annulus 202 below seal element 210B	-calculate lower seal element 210B leakage rate -indicate lower seal element 210B leakage -display alarm or notification if lower seal element 210B leakage rate exceeds set point
combination of pressure in bearing assembly 206, and pressure of fluid in annulus 202 below seal element 210B	-indicate if seal element 210 is worn -indicate if lubrication system is working properly -display alarm or notification if set point of pressure in bearing assembly 206 at differential above wellbore pressure is not maintained for certain time period -indicate if pressure inside bearing assembly 206 should be increased or decreased -regulate flow rate of lubrication fluid through lubrication system to bearing assembly 206 to maintain pressure in bearing assembly 206 at set point
combination of cooling circuit inlet temperature and outlet temperatures	-indicate amount of heat being transferred into cooling circuit from bearing assembly 206 -indicate heat transfer rate of cooling circuit -display alarm or notification if heat transfer rate is below estimated required value based on torque, wellbore temperature, bearing assembly 206 temperature, and inlet/outlet temperatures of cooling circuit
combination of revolutions per minute (RPM) of bearing assembly 206 and RPM of drill string 104	-indicate element slippage and if element is worn -estimate lifetime of seal element 210 -estimate lifetime of bearing in bearing assembly 206 -estimate lifetime of other elements -display RPM of bearing assembly 206, RPM of drill string 104, and difference between two values -display alarm or notification if difference exceeds specified limit for specified duration
combination of	-indicate lifetime of element

Drilling Condition	Interpretation, Conclusions, and/or Actions Based on Drilling Conditions
temperature and pressure profile of service, length of exposure time, slippage, number of tool joints 214 stripped, and stripping rate	-display available element lifetime based on moving average of current conditions -display alarm or notification if available element lifetime is below specified limit -display available element lifetime based on cumulative average of conditions -display alarm or notification if available element lifetime is below specified limit -indicate lifetime of bearing in bearing assembly 206 -display available bearing lifetime based on moving average of current conditions -display alarm or notification if available bearing lifetime is below specified limit -display available bearing lifetime based on cumulative average of conditions -display alarm or notification if available bearing lifetime is below specified limit
combination of temperature and pressure profile of service, length of exposure time, torque, and profile of lifetime of bearing in bearing assembly 206	-indicate lifetime of seal element 210 -display available seal element 210 lifetime based on moving average of current conditions -display alarm or notification if available seal element 210 lifetime is below specified limit -display available seal element 210 lifetime based on cumulative average of conditions -display alarm or notification if available seal element 210 lifetime is below specified limit

FIGURE 4 illustrates a flow chart of an example method for monitoring drilling conditions associated with a rotating control device during drilling operations in accordance with some embodiments of the present disclosure. The method is described as being performed by sensors 212 described with respect to FIGURE 2 and processing system 304 described with respect to FIGURE 3, however, any other suitable system, apparatus or device may be used. Generally, sensors 212 may be associated with standpipe 118 and/or with RCD 106 to measure various drilling conditions during drilling operations. The drilling conditions may include, but are not limited to, strain, pressure, temperature, flow rate, position, distance and vibration. The measured values for the

various drilling conditions may be analyzed by processing system 304 in order to make a determination of what action may be taken during drilling operations. If processing system 304 determines that an action should be taken, processing system 304 may generate an alarm to alert an operator of drilling system 100. On the other hand, if processing system 304 determines no action should be taken, drilling operations may continue.

Method 400 may start, and at step 402, sensors 212 may measure one or more drilling conditions associated with RCD 106 during drilling operations. The drilling conditions may include, but are not limited to, pressure, temperature, flow rate, vibration, position, torque, strain and tool joint count. As described above and in Table B, these drilling conditions may be used to determine various actions that can be taken during drilling operations.

At step 404, sensors 212 may communicate the detected drilling conditions to processing system 304 that is configured to receive measurements from sensors 212 during drilling operations. In some embodiments, data representing the drilling conditions may be communicated from sensors 212 to input device 302 using transmitters/receivers in various locations of a drilling system (e.g., drilling system 100 as shown in FIGURE 1). The locations may include, but are not limited to, (i) body 204, bearing assembly 206, tie back and upper stripper of RCD 106, (ii) the hydraulic power unit (HPU), (iii) the work platform, the control console and the rig floor of the drilling unit, such drilling unit 102 of FIGURE 1, and (iv) near the wellhead. In other embodiments, the data from sensors 212 may be communicated through wires, such as electrical wires or fiber optics. In additional embodiments, communication of the drilling conditions from sensors 212 may be wireless. For example, the signals carrying the drilling conditions may be acoustic, electromagnetic or optical. The measurements may be communicated by sensors 212 either continuously or based on a pre-determined time interval.

At step 406, processing system 304 may analyze the data associated with the drilling conditions detected by sensors 212. In one embodiment, processing system 304 may compare the detected drilling conditions to a pre-determined threshold. If the detected drilling condition is above or below the pre-determined threshold, depending on the particular drilling condition, processing system 304 may determine an action that may be taken. The comparison to the pre-determined threshold may be based on a single

measurement of the particular drilling condition or a change (either an increase or decrease) in the drilling condition over time. Additionally, processing system 304 may analyze the data based on one drilling condition or a combination of several drilling conditions. In some embodiments, the detected drilling conditions may be used to calculate the estimated lifetime of seal element 210 and/or the bearings of bearing assembly 206 during the drilling operations. Other examples of how processing system 304 may analyze the measured data are described in Table B.

At step 408, processing system 304 may determine whether an action should be taken based on the analyzed data. If processing system 304 determines that no action should be taken, drilling operations may continue at step 410 and method 400 may return to step 402 to continue measuring the drilling conditions. If processing system 304 determines that an action should be taken, processing system 304 may generate an alarm to alert an operator of drilling system 100 at step 412. Example alarms that may be generated are described in Table B. At step 414, the operator may take an action based on the alarm and/or processing system 304 may automatically take the action by adjusting one or more drilling parameters. Example actions that may be taken by either the operator and/or processing system 304 are described in Table B.

Modifications, additions, or omissions may be made to method 400 without departing from the scope of the present disclosure. For example, the order of the steps may be performed in a different manner than that described and some steps may be performed at the same time. Additionally, each individual step may include additional steps without departing from the scope of the present disclosure.

FIGURE 5 illustrates a flow chart of an alternative example method for monitoring drilling conditions associated with a drilling system in accordance with some embodiments of the present disclosure. The method is described as being performed by sensors 212 described with respect to FIGURE 2 and control system 300 described with respect to FIGURE 3, however, any other suitable system, apparatus or device may be used. Generally, sensors 212 may be associated with standpipe 118 and/or with RCD 106 to measure various drilling conditions during drilling operations. The drilling conditions may include, but are not limited to, strain, pressure, temperature, flow rate, position, distance and vibration. In addition, other various sources of information regarding a drilling system may be provided, for example, from a MWD system. The measured values for the various drilling conditions may be analyzed by processing system 304 in

order to make a determination of whether an alarm should be generated and an action taken.

Method 500 may start, and at step 502, sensor 212 may measure a drilling condition associated with a drilling system (e.g., drilling system 100 as illustrated in FIGURE 1). The drilling condition may include, but is not limited to, pressure, temperature, flow rate, vibration, position, torque, strain and tool joint count.

At step 504, sensor 212 may communicate the detected drilling condition data to processing system 304 that is configured to receive measurements from sensors 212. In some embodiments, data representing the drilling conditions may be communicated from sensors 212 to input device 302 using transmitters/receivers in various locations of a drilling system (e.g., drilling system 100 as shown in FIGURE 1). The locations may include, but are not limited to, (i) body 204, bearing assembly 206, tie back and upper stripper of RCD 106, (ii) the hydraulic power unit (HPU), (iii) the work platform, the control console and the rig floor of the drilling unit, such drilling unit 102 of FIGURE 1, and (iv) near the wellhead. In other embodiments, the data from sensors 212 may be communicated through wires, such as electrical wires or fiber optics. In additional embodiments, communication of the drilling conditions from sensors 212 may be wireless. For example, the signals carrying the drilling conditions may be acoustic, electromagnetic or optical. The measurements may be communicated by sensors 212 either continuously or based on a pre-determined time interval.

At step 506, processing system 304 may store the raw drilling condition data. For example, processing system 304 may store the raw drilling condition data in storage device 316 local to the drilling system. In some embodiments, processing system 304 may store the raw data in a storage device remote from the drilling system. This may be facilitated by outputting the raw drilling condition data through outputs 310 to a remote location. For example, processing system 304 may use outputs 310 to transmit the raw drilling condition data wireless to a storage facility remote from the drilling system. The raw drilling condition data may be stored with a time stamp, an identification of sensor 212, identification of the drilling system, and/or other identifying information.

At step 508, processing system 304 may determine whether the raw drilling condition data is usable when processed using a scalar function or some type of algorithm. For example, if the drilling condition is one of temperature, pressure, flow rate, vibration, latch position, or torque, processing system 304 may process the raw

drilling condition data using a scalar function. In some embodiments, processing system 304 may use raw position data from proximity sensors, distance sensors, or mechanical sensors to calculate revolutions per minute (RPM) of bearing assembly 206 and/or drill string 104 and tool joint stripping rate or rate of penetration (ROP) using an algorithm.

At steps 510 and 512, processing system 304 processes the received drilling condition using the appropriate processing scheme. For example, at step 510, a scalar function may be used to process raw the drilling condition data to produce processed drilling condition data. In some embodiments, at step 512 processing system 304 may processes the received raw drilling condition data using an algorithm to produce processed drilling condition data.

At step 514, processing system 304 may store the processed drilling condition data. This may be stored in a similar manner to the raw drilling condition data stored at step 506. For example, the processed drilling condition data may be stored locally to drilling system in storage device 316 or may be stored in a remote facility.

At step 516, processing system 304 may determine whether a desired factor, factor *i*, may be based on a combination of drilling conditions or if a single drilling condition is used to determine the desired factor. A factor may include processed drilling condition data, for example, raw pressure drilling condition data processed using a scalar function, or as another example, raw position data processed using an algorithm to determine RPM of bearing assembly 206. A factor may also include any of the other calculated, estimated, or determined information as described in Table A or Table B, for example, expected lifetime of bearings in bearing assembly 206, or heat being transferred to a cooling circuit. If it is determined that the given desired factor uses a single drilling condition, method 500 may proceed to step 520. If it is determined that the given desired factor may be based on more than one, or in other words, a combination of drilling conditions to be determined, method 500 may proceed to step 518.

At step 518, processing system 304 may determine if all processed drilling conditions used to determine factor *i* have been received. For example, if the desired factor *i* was the lifetime of a bearing in bearing assembly 206, pressure inside bearing assembly 206 and temperature inside bearing assembly 206 may both be utilized to determine factor *i*. Thus, in this example, processing system 304 may determine if both pressure and temperature inside bearing assembly 206 were received and processed. If less than all of the drilling conditions used to determine factor *i* have been received,

method 500 may return to the start of the method to repeat the steps to receive and process additional drilling conditions until all of the drilling conditions have been received and processed to determine desired factor *i*. If all of the drilling conditions used to determine factor *i* have been received, method 500 may proceed to step 520. At step 520, processing system 304 may determine factor *i* based on the processed drilling condition(s).

At step 522, processing system 304 may determine whether factor *i* has passed a trigger point, or in other words, whether the value determined for factor *i* has dropped below or gone above a pre-determined threshold value. If it is determined that factor *i* has not passed the trigger point, method 500 may return to the start of the method. If it is determined that factor *i* has passed the trigger point, method 500 may continue to step 524.

At step 524, processing system 304 may determine whether factor *i* waits to trigger an alarm until factor *i* is past the trigger point for a certain duration of time before an alarm is generated. For example, as described in Table B, if factor *i* is the slippage of elements based on RPM of drill string 104 and RPM of bearing assembly 206, an alarm may be displayed when the difference between the two RPMs exceeds a specified limit for a specified duration. If it is determined that factor *i* does not wait until the value of factor *i* is past the trigger point for a given duration to generate an alarm, method 500 may proceed to step 528. If it is determined that factor *i* waits until the value of factor *i* is past the trigger point for a given duration to generate an alarm, method 500 may proceed to step 526. At step 526, processing system 304 determines whether the given duration of time has been exceeded. If the duration of time has been exceeded, method 500 may proceed to step 528. If the duration of time has not been exceeded, method 500 may return to the start of method 500.

At step 528, processing system 304 may generate an alarm. For example, the alarm may be displayed on display 306 or may be printed at printer 308. At step 530, processing system 304 may store the alarm that is generated. This may be stored in a similar manner to the storage performed at steps 506 and/or 514. For example, alarm may be stored locally to the drilling system and/or stored remotely. As an additional example, the generated alarm may be stored with a time stamp or other identifying information.

At step 532, processing system 304 may determine whether an action is advisable based on the generated alarm. For example, if the alarm indicates that a cooling circuit should increase the flow rate of the cooling fluid, processing system 304 may output a signal to the cooling circuit directing it to increase the flow rate of the cooling fluid. If an action is not advisable, method 500 may return to the start of method 500. If an action is advisable, method 500 may proceed to step 534 to perform an automated action to address the generated alarm. Some examples of automated actions that may be taken are disclosed in Table B. It will be appreciated that an operator of the drilling system may take an action based on the alarm which has been generated.

Modifications, additions, or omissions may be made to method 500 without departing from the scope of the present disclosure. For example, the order of the steps may be performed in a different manner than that described and some steps may be performed at the same time. Additionally, each individual step may include additional steps without departing from the scope of the present disclosure.

Although the present disclosure and its advantages have been described in detail, it should be understood that various changes, substitutions and alterations can be made herein without departing from the spirit and scope of the disclosure as defined by the following claims.

WHAT IS CLAIMED IS:

1. A drilling system, comprising:

a rotating control device (RCD);

a plurality of sensors included in or in proximity to the RCD, each of the sensors configured to detect a drilling condition associated with the RCD during a drilling operation; and

a control system configured to determine an adjustment to a drilling parameter during drilling operations based on the detected drilling conditions.

2. The drilling system of Claim 1, wherein the detected drilling conditions are selected from the group consisting of pressure, temperature, flow rate, vibration, position, torque, strain and tool joint count.

3. The drilling system of Claim 1, wherein the sensors are selected from the group consisting of a pressure transducer, a temperature transducer, a thermocouple, a proximity sensor, a distance sensor, an accelerometer and a strain gauge.

4. The drilling system of Claim 1, wherein the sensors are included in or in proximity to a seal element of the RCD.

5. The drilling system of Claim 4, wherein the seal element comprises a plurality of seals and each of the plurality of seals is included in or in proximity to at least one of the plurality of sensors.

6. The drilling system of Claim 4, wherein the control system is further configured to calculate an estimated lifetime of the seal element based on the detected drilling conditions.

7. The drilling system of Claim 1, wherein the sensors are included in or in proximity to a bearing assembly of the RCD.

8. The drilling system of Claim 7, wherein the control system is further configured to calculate an estimated lifetime of bearings in the bearing assembly based on the detected drilling conditions.

9. The drilling system of Claim 7, wherein the control system is further configured to calculate revolutions per minute of the bearing assembly based on the detected drilling conditions.

10. The drilling system of Claim 7, wherein the control system is further configured to calculate rate of penetration of the drill string based on the detected drilling conditions.

11. The drilling system of Claim 1, wherein the sensors are included in or in proximity to a latch assembly of the RCD.

12. The drilling system of Claim 11, wherein the control system is further configured to determine engagement of latch assembly based on the detected drilling conditions.

13. The drilling system of Claim 1, wherein one of the plurality of sensors is included in or in proximity to a casing collar locator (CCL).

14. A method comprising:

measuring a plurality of drilling conditions by a plurality of sensors included in or in proximity to a rotational control device (RCD) of a drilling system during drilling operations;

communicating the plurality of drilling conditions to a processing system;

analyzing the drilling conditions by the processing system;

generating an alarm based on the analyzed drilling conditions; and

adjusting a drilling parameter based on the alarm.

15. The method of Claim 14, wherein the drilling parameter is adjusted by an operator of the drilling system.

16. The method of Claim 14, wherein the drilling parameter is automatically adjusted by the processing system.

17. The method of Claim 14, further comprising storing at least one of the drilling conditions communicated to the processing system and the alarm.

18. The method of Claim 17, wherein the at least one of the drilling conditions communicated to the processing system and the alarm are stored with a time stamp.

19. A rotational control device comprising:

a body including a first sensor;

a seal element configured to seal an annulus between the body and a drill string of a drilling system, the seal element including a second sensor; and

a bearing assembly coupled to the seal element to facilitate motion of the drill string relative to the body, the bearing assembly comprising a third sensor.

20. The rotational control device of Claim 19, further comprising a latch assembly, the latch assembly comprising a fourth sensor and a remotely operable hydraulic clamp or latch to selectively secure and release the bearing assembly relative to the body.

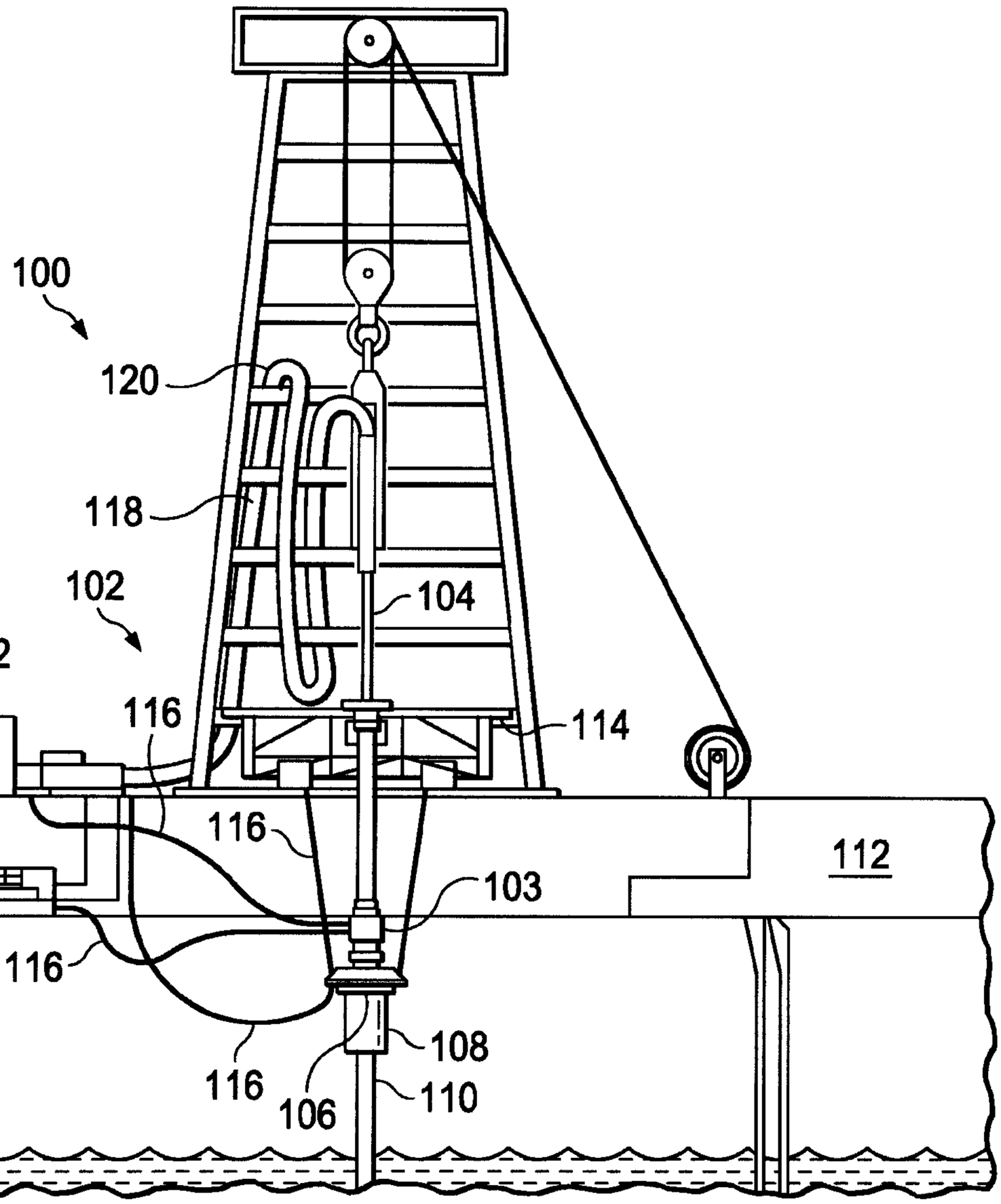

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FIG. 1

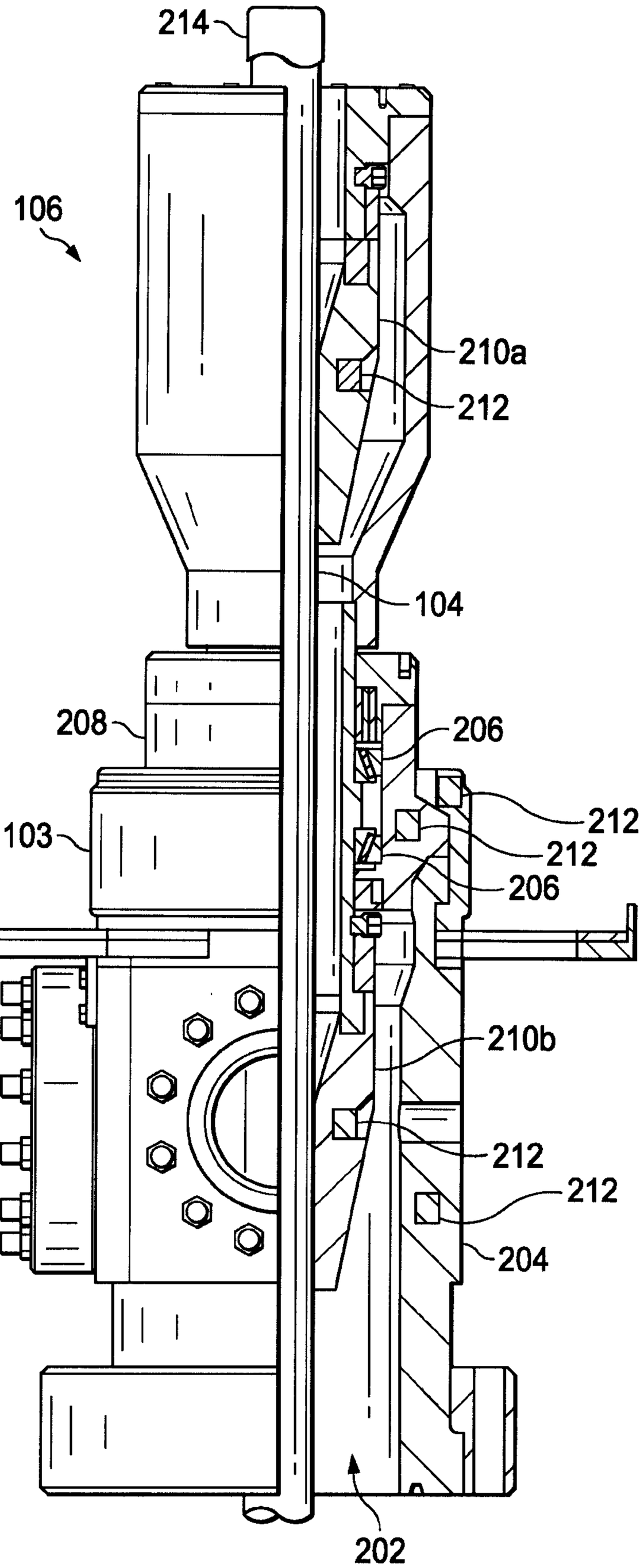
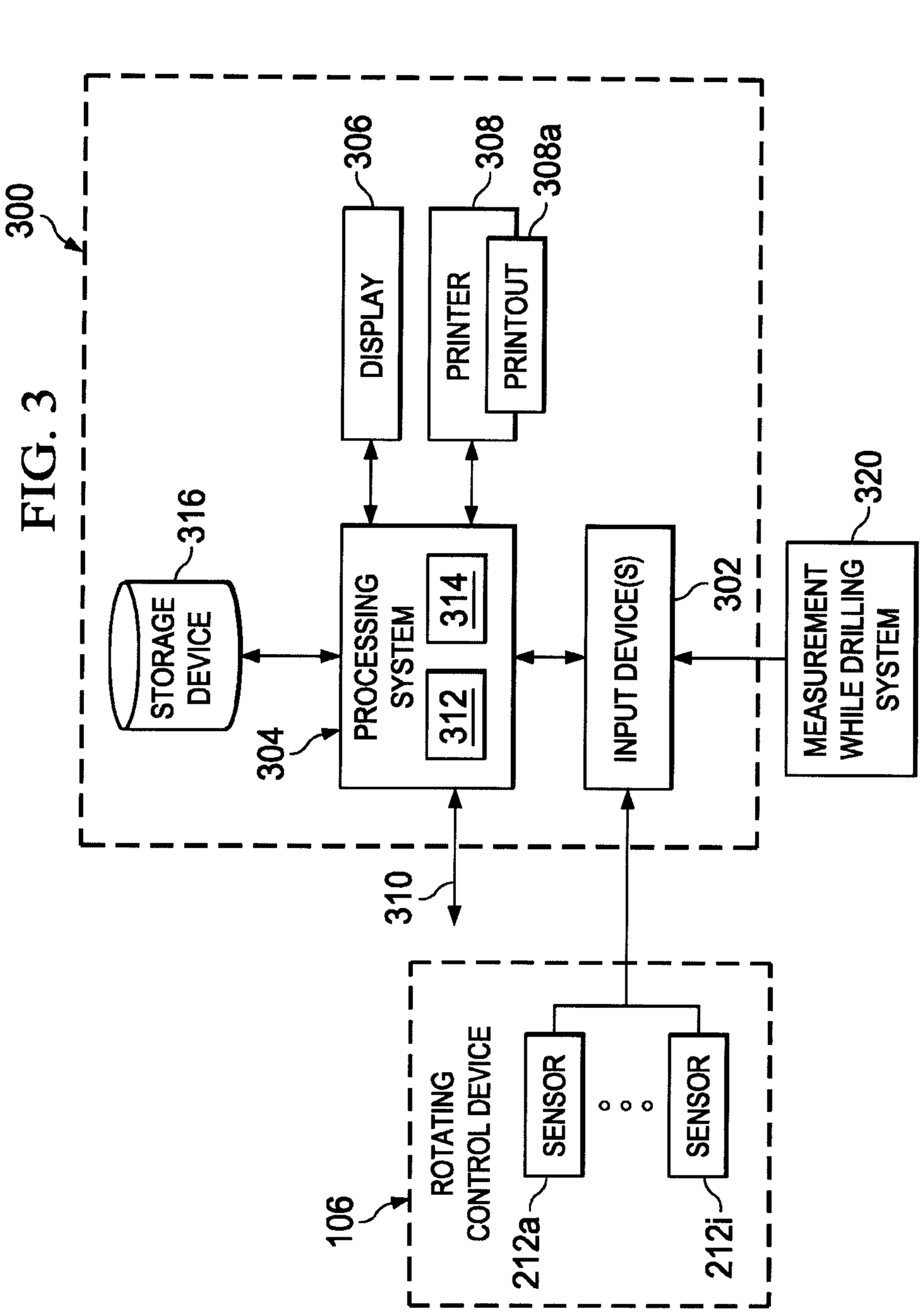

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210a
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104
208
206
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103
212
206
210b
212
212
204
202

FIG. 2

FIG. 3


300
306
DISPLAY
308
PRINTER
308a
PRINTOUT
316
STORAGE DEVICE
304
PROCESSING SYSTEM
314
312
INPUT DEVICE(S)
302
MEASUREMENT WHILE DRILLING SYSTEM
320
310
106
ROTATING CONTROL DEVICE
SENSOR
212a
SENSOR
212i

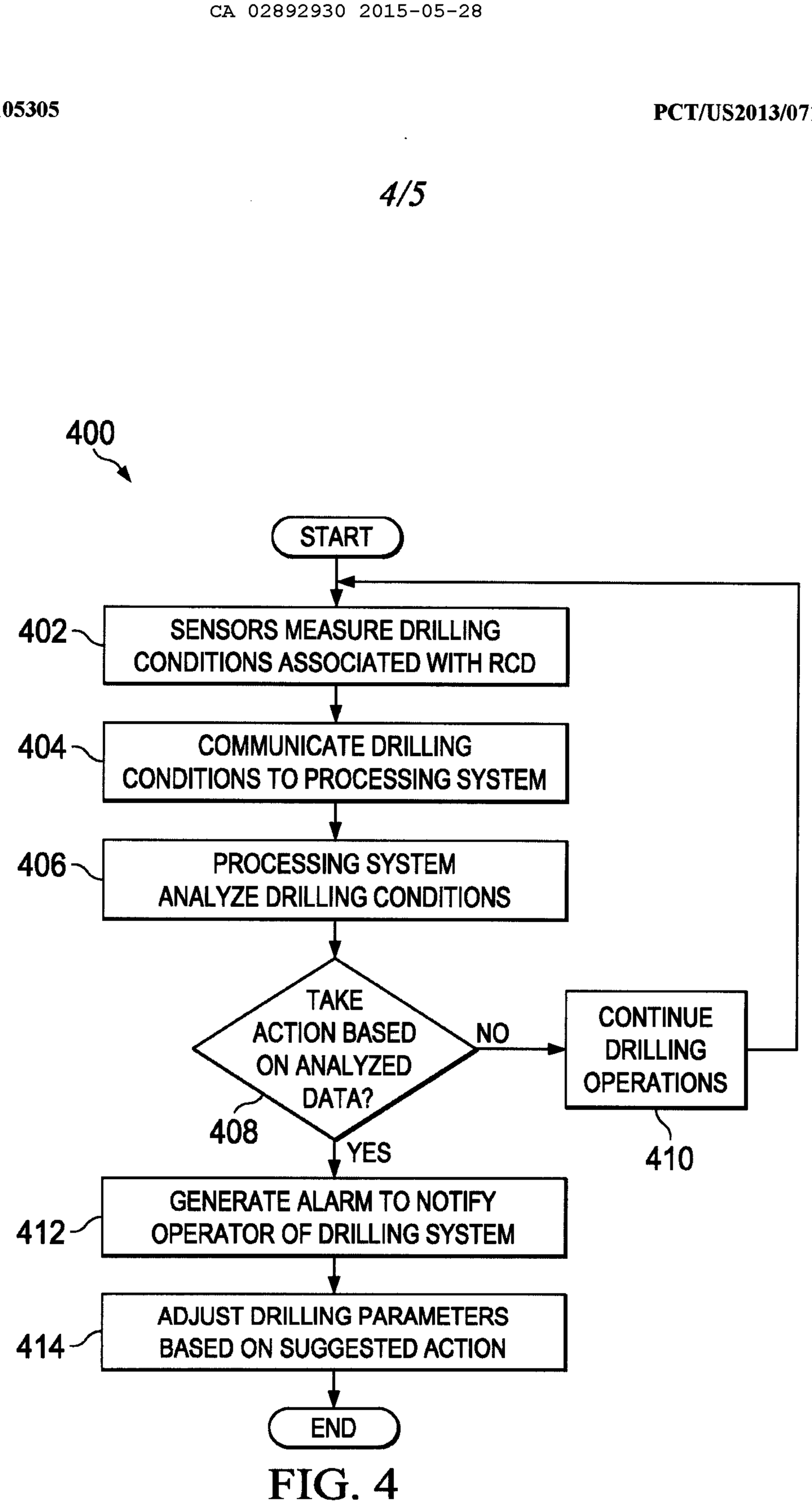
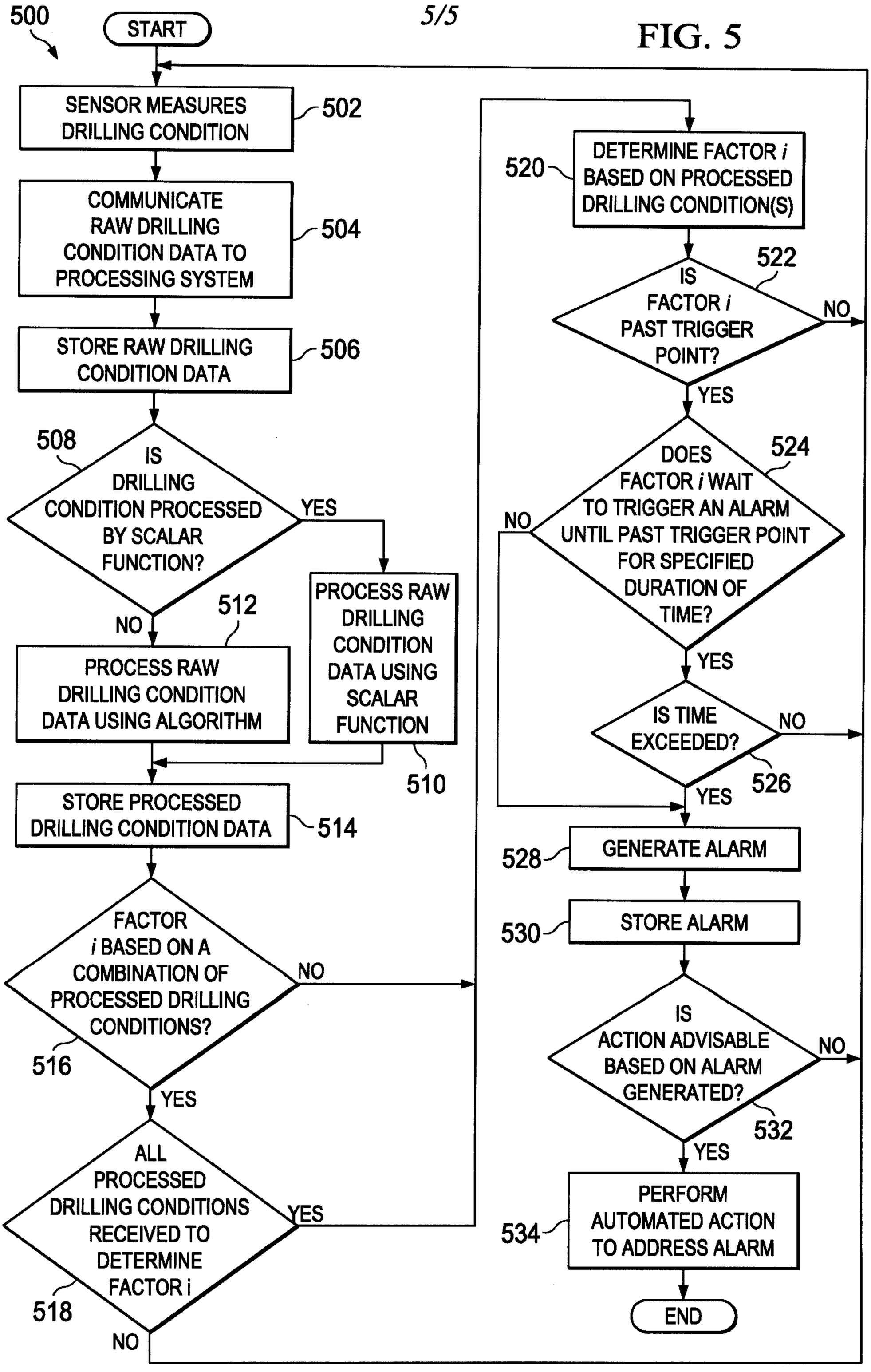

400
START
402
SENSORS MEASURE DRILLING CONDITIONS ASSOCIATED WITH RCD
404
COMMUNICATE DRILLING CONDITIONS TO PROCESSING SYSTEM
406
PROCESSING SYSTEM ANALYZE DRILLING CONDITIONS
TAKE ACTION BASED ON ANALYZED DATA?
408
NO
CONTINUE DRILLING OPERATIONS
410
YES
412
GENERATE ALARM TO NOTIFY OPERATOR OF DRILLING SYSTEM
414
ADJUST DRILLING PARAMETERS BASED ON SUGGESTED ACTION
END

FIG. 4

FIG. 5


500
START
SENSOR MEASURES DRILLING CONDITION
502
COMMUNICATE RAW DRILLING CONDITION DATA TO PROCESSING SYSTEM
504
STORE RAW DRILLING CONDITION DATA
506
508
IS DRILLING CONDITION PROCESSED BY SCALAR FUNCTION?
YES
NO
512
PROCESS RAW DRILLING CONDITION DATA USING ALGORITHM
PROCESS RAW DRILLING CONDITION DATA USING SCALAR FUNCTION
510
STORE PROCESSED DRILLING CONDITION DATA
514
FACTOR i BASED ON A COMBINATION OF PROCESSED DRILLING CONDITIONS?
516
NO
YES
ALL PROCESSED DRILLING CONDITIONS RECEIVED TO DETERMINE FACTOR i
518
YES
NO
520
DETERMINE FACTOR i BASED ON PROCESSED DRILLING CONDITION(S)
522
IS FACTOR i PAST TRIGGER POINT?
NO
YES
524
DOES FACTOR i WAIT TO TRIGGER AN ALARM UNTIL PAST TRIGGER POINT FOR SPECIFIED DURATION OF TIME?
NO
YES
IS TIME EXCEEDED?
NO
YES
526
528
GENERATE ALARM
530
STORE ALARM
IS ACTION ADVISABLE BASED ON ALARM GENERATED?
NO
532
YES
534
PERFORM AUTOMATED ACTION TO ADDRESS ALARM
END

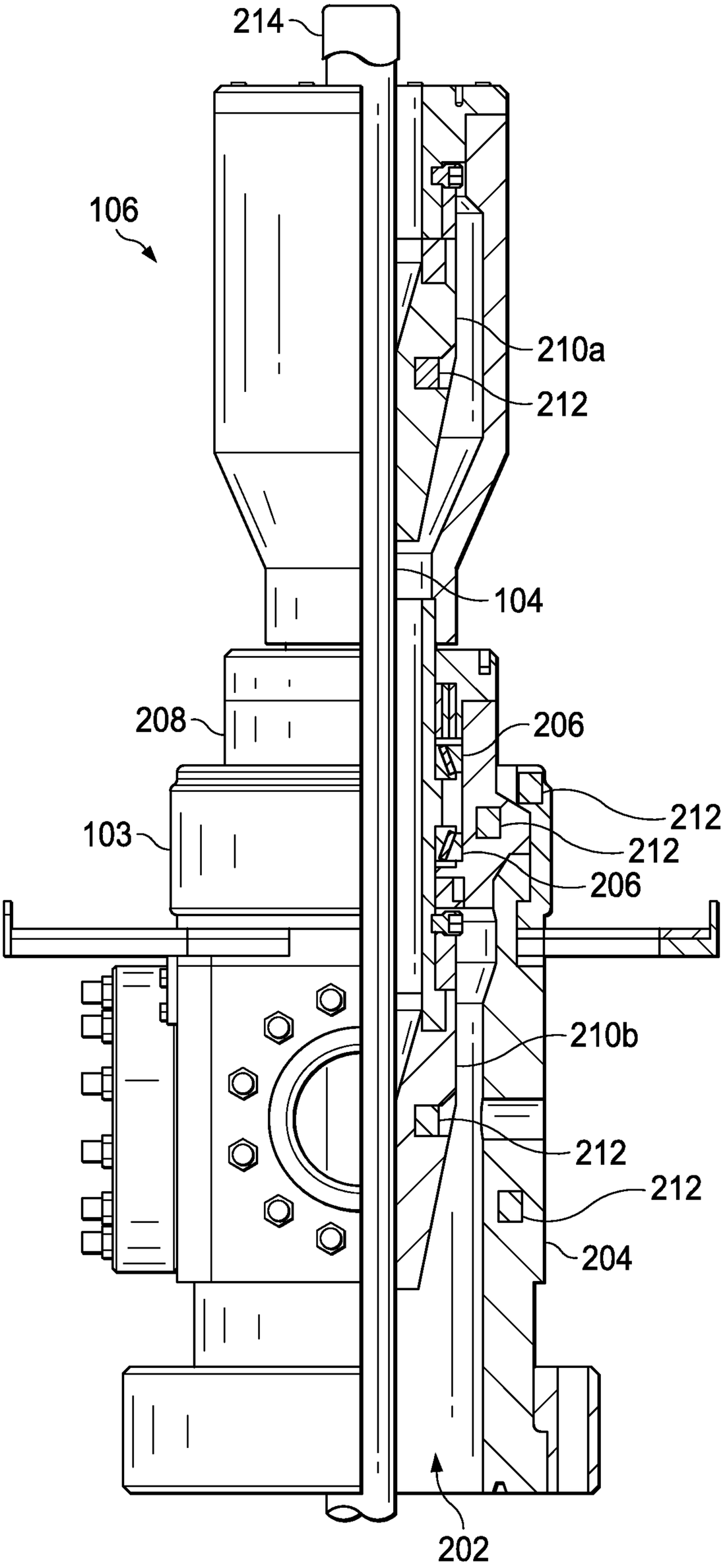

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210b
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FIG. 2