

(51) International Patent Classification:
E21B 44/00 (2006.01)(21) International Application Number:
PCT/US2016/037842(22) International Filing Date:
16 June 2016 (16.06.2016)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
62/181,982 19 June 2015 (19.06.2015) US
15/008,161 27 January 2016 (27.01.2016) US(71) Applicant: WEATHERFORD TECHNOLOGY HOLD-
INGS, LLC [US/US]; 2000 St. James Place, Houston,
Texas 77056 (US).(72) Inventors: SALMINEN, Kent Patrick; 707 Archer Street,
Houston, Texas 77009 (US). CHEATHAM, Curtis Alan;
7 Childres Pond Court, The Woodlands, Texas 77389
(US). SMITH, Mark Adrian; 12811 Ashford Meadow
Drive, Houston, Texas 77082 (US).(74) Agents: PATTERSON, William B. et al.; Patterson &
Sheridan, LLP, 24 Greenway Plaza, Suite 1600, Houston,
Texas 77046 (US).(81) Designated States (unless otherwise indicated, for every
kind of national protection available): AE, AG, AL, AM,
AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY,
BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM,
DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT,
HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR,
KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG,
MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM,
PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC,
SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN,
TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.(84) Designated States (unless otherwise indicated, for every
kind of regional protection available): ARIPO (BW, GH,
GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ,
TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU,
TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE,
DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU,
LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK,
SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ,
GW, KM, ML, MR, NE, SN, TD, TG).

Published:

— with international search report (Art. 21(3))

(54) Title: REAL-TIME STUCK PIPE WARNING SYSTEM FOR DOWNHOLE OPERATIONS

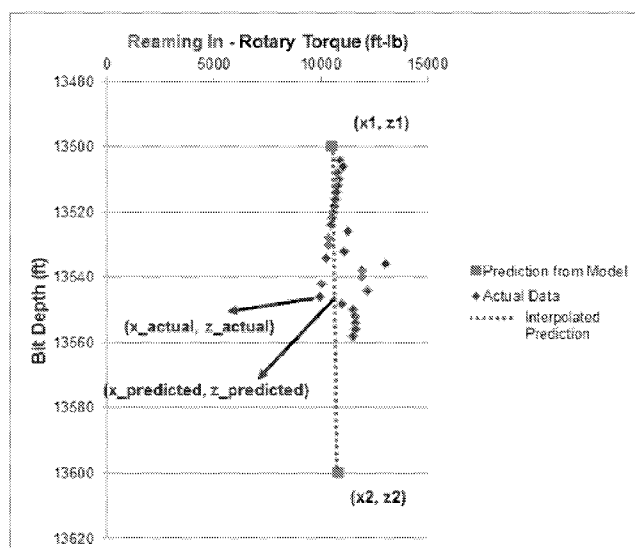


FIG. 5A

(57) Abstract: A method of performing an operation
in a wellbore includes performing the operation in
the wellbore from a rig; and, while performing the
operation, repeatedly: inputting one or more pre-
dicted values from a model of the wellbore; inputting
one or more measured parameters from one or more
sensors of the rig; calculating a deviation of each
measured parameter from a respective predicted
value; applying a weighting factor to each calculated
deviation to obtain a respective alert level; calculat-
ing a rate of change of each measured parameter
from a parameter previously measured by the respec-
tive sensor; applying a weighting factor to each
calculated rate of change to obtain a respective alert
level; and adding the alert levels and dividing the
sum thereof by a maximum alert level to obtain a
stuck pipe risk.

REAL-TIME STUCK PIPE WARNING SYSTEM FOR DOWNHOLE OPERATIONS

BACKGROUND OF THE DISCLOSURE

Field of the Disclosure

[0001] The present disclosure generally relates to a real-time stuck pipe warning system for downhole operations.

Description of the Related Art

[0002] A wellbore is formed to access hydrocarbon-bearing formations (e.g., crude oil and/or natural gas) or for geothermal power generation by the use of drilling. Drilling is accomplished by utilizing a drill bit that is mounted on the end of a drill string. To drill within the wellbore to a predetermined depth, the drill string is often rotated by a top drive on a drilling rig. After drilling to a predetermined depth, the drill string and drill bit are removed and a string of casing is lowered into the wellbore. An annulus is thus formed between the casing string and the wellbore. The casing string is hung from the wellhead. A cementing operation is then conducted in order to fill the annulus with cement. The casing string is cemented into the wellbore by circulating cement into the annulus defined between the outer wall of the casing and the borehole. The combination of cement and casing strengthens the wellbore and facilitates the isolation of certain areas of the formation behind the casing for the production of hydrocarbons.

[0003] Stuck pipe during drilling is a common and expensive problem. Operating companies lose valuable rig time due to stuck pipe and in the worst case can lose an entire wellbore section along with the bottom hole assembly (BHA) of the drill string. Service companies lose the value of the BHA while also suffering opportunity cost. Several companies have developed practices for preventing stuck pipe along with remedial actions in the event of stuck pipe. However, these practices are not standard across the industry and too often focus primarily on after-the-fact solutions. Stuck pipe is so prevalent that it is sometimes considered a normal operating risk. Stuck pipe may also be a problem for other downhole operations besides drilling.

SUMMARY OF THE DISCLOSURE

[0004] The present disclosure generally relates to a real-time stuck pipe warning system for downhole operations. In one embodiment, a method of performing an operation in a wellbore includes performing the operation in the wellbore from a rig; and, while performing the operation, repeatedly: inputting one or more predicted values from a model of the wellbore; inputting one or more measured parameters from one or more sensors of the rig; calculating a deviation of each measured parameter from a respective predicted value; applying a weighting factor to each calculated deviation to obtain a respective alert level; calculating a rate of change of each measured parameter from a parameter previously measured by the respective sensor; applying a weighting factor to each calculated rate of change to obtain a respective alert level; and adding the alert levels and dividing the sum thereof by a maximum alert level to obtain a stuck pipe risk.

BRIEF DESCRIPTION OF THE DRAWINGS

[0005] So that the manner in which the above recited features of the present disclosure can be understood in detail, a more particular description of the disclosure, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this disclosure and are therefore not to be considered limiting of its scope, for the disclosure may admit to other equally effective embodiments.

[0006] Figure 1 illustrates slide drilling of a wellbore using a drilling system having a stuck pipe warning system, according to one embodiment of the present disclosure.

[0007] Figure 2 illustrates one method of operation of the stuck pipe warning system.

[0008] Figures 3A and 3B illustrate allowable deviations and rates of change obtained from historical data for use in operation of the stuck pipe warning system.

[0009] Figures 4A and 4B illustrate sample windows and selection thereof for

various rig activities by the stuck pipe warning system.

[0010] Figures 5A and 5B illustrate interpolation of predicted values from a model by the stuck pipe warning system.

[0011] Figure 6A illustrates calculation of a deviation of a measured parameter by the stuck pipe warning system. Figure 6B illustrates application of a weighting factor to the calculated deviation to obtain an alert level by the stuck pipe warning system. Figure 6C illustrates calculation of a rate of change of an average of a measured parameter by the stuck pipe warning system. Figure 6D illustrates application of a weighting factor to the calculated rate of change to obtain an alert level by the stuck pipe warning system. Figure 6E illustrates calculation of a stuck pipe risk by the stuck pipe warning system.

[0012] Figure 7 illustrates display of the stuck pipe risk by the stuck pipe warning system.

[0013] Figure 8 illustrates rotary drilling of the wellbore using the drilling system.

[0014] Figure 9 illustrates tripping a drill string of the drilling system from the wellbore.

[0015] Figure 10 illustrates reaming of the wellbore using the drilling system.

[0016] Figure 11 illustrates reaming a liner string into the wellbore using the drilling system.

[0017] Figure 12 illustrates an alternative method of operation of the stuck pipe warning system.

DETAILED DESCRIPTION

[0018] Figure 1 illustrates slide drilling of a wellbore 2 using a drilling system 1 having a stuck pipe warning system 3 (Figure 2), according to one embodiment of the present disclosure. The drilling system 1 may further include a drilling rig 1r, a fluid handling system 1f, a pressure control assembly 1p, a drill string 4, and a rig

controller, such as a programmable logic controller (PLC) 15. The stuck pipe warning system 3 may include operating steps 31-42 (Figure 2), operating steps 61-72 (Figure 12) loaded onto the PLC 15 for execution thereby during slide drilling. The drilling rig 1r may include a derrick 5d, a floor 5f, a top drive 6, and a hoist 7. The rig floor 5f may have an opening through which the drill string 4 extends downwardly into the PCA 1p.

[0019] Alternatively, the operating steps 31-42, 61-72 may be loaded onto an auxiliary computer in data communication with the PLC 15, such as a desktop, server, laptop, netbook, tablet, or smart phone.

[0020] The drill string 4 may include a bottomhole assembly (BHA) 4b and a pipe string 4s. The pipe string 4s may include joints of drill pipe connected together, such as by threaded couplings. The BHA 4b may be connected to the pipe string 4s, such as by threaded couplings. The BHA 4b may include a drill bit 8, a stabilizer 9, a steerable drilling motor (ST MOT) 10, and a measurement while drilling (MWD) tool 11. The BHA members 8-11 may be interconnected, such as by threaded couplings. The drill bit 8 may be rotated 14m by the steerable drilling motor 10. The steerable drilling motor 10 may be a mud motor, such as a progressive cavity motor, operated by harnessing mechanical energy from hydraulic energy of drilling fluid 25d pumped through the BHA 4b. The steerable drilling motor 10 may have a deviated (aka bent) output shaft for directional drilling.

[0021] Alternatively, the drill string 4 may include coiled tubing and an orienter instead of the pipe string 4s.

[0022] The MWD tool 11 may include a mandrel having threaded couplings formed at each longitudinal end thereof, an electronics package mounted on the mandrel, a sensor package mounted on the mandrel, a housing connected to the mandrel to protect the packages, and a battery disposed between the housing and the mandrel. The electronics package may include a microcontroller, a clock, and an analog to digital converter. The electronics package and sensor package may be in electrical communication by leads, a bus, or integration on a printed circuit board. The sensor package may include an inclination sensor and an azimuth

sensor. The MWD electronics package may further include a modem in electrical communication with an uplink (not shown) for operation thereof to send measurements by the sensor package to the PLC 15. The uplink may be a mud pulser or a gap sub for sending the measurements via electromagnetic telemetry.

[0023] An upper end of the pipe string 4s may be connected to a quill of the top drive 6, such as by threaded couplings. The top drive 6 may include a motor for rotating 14t (Figure 8) the drill string 4. The top drive motor may be electric or hydraulic. A frame of the top drive 4 may be coupled to a rail (not shown) of the derrick 5d for preventing rotation thereof during rotation 14t of the drill string 4 and allowing for vertical movement of the top drive with a traveling block 7t of the rig hoist 7. The frame of the top drive 6 may be suspended from the derrick 5d by the traveling block 7t. The traveling block 7t may be supported by wire rope 7r connected at its upper end to a crown block 7c of the rig hoist 7. The wire rope 7r may be woven through sheaves of the blocks 7c,t and extend to drawworks 7d of the hoist 7 for reeling thereof, thereby raising or lowering the traveling block 7t relative to the derrick 5d.

[0024] The PCA 1p may include one or more blow out preventers (BOPs) and a flow cross. A housing of each BOP and the flow cross may each be interconnected and/or connected to a wellhead 16, such as by a flanged connection. The wellhead 16 may be mounted on a casing string 17 which has been deployed into the wellbore 2 drilled from a surface 18s of the earth and cemented into the wellbore. The casing string 17 may extend to a depth adjacent a bottom of an upper formation 18u. The upper formation 18u may be non-productive and a lower formation 18b may be a hydrocarbon-bearing reservoir.

[0025] Alternatively, the lower formation 18b may be non-productive (e.g., a depleted zone), environmentally sensitive, such as an aquifer, or unstable. Alternatively, the wellbore 2 may be subsea having a wellhead located adjacent to the waterline and the drilling rig 1r may be a located on a platform adjacent the wellhead. Alternatively, the wellbore 2 may be subsea having a wellhead located adjacent to the seafloor and the drilling rig 1r may be a located on an offshore drilling unit.

[0026] The fluid system 1f may include a mud pump 19, a drilling fluid reservoir, such as a pit 20 or tank, a solids separator, such as a shale shaker 21, a pressure sensor 22, one or more flow lines, such as a return line 23, a supply line 24, and a feed line. A first end of the return line 23 may be connected to the flow cross of the PCA 1p and a second end of the return line may be connected to an inlet of the shaker 21. A lower end of the supply line 24 may be connected to an outlet of the mud pump 19 and an upper end of the supply line may be connected to an inlet of the top drive 6. The pressure sensor 22 may be assembled as part of the supply line 24.

[0027] The pressure sensor 22 may be in data communication with the PLC 15 and may be operable to monitor standpipe pressure (SPP). The PLC 15 may also be in communication with a hook load detector (depicted by dotted line to crown block 7c) clamped to the wire rope 7r, and a position sensor of the drawworks 7d for monitoring depth of the drill bit 8. The PLC 15 may further be in communication with a torque sensor of the top drive 6 (depicted by dotted line to the top drive).

[0028] To extend the wellbore 2 from the casing shoe into the lower formation 18b, the mud pump 19 may pump the drilling fluid 25d from the pit 20, through the supply line 24, and to the top drive 6. The drilling fluid 25d may include a base liquid. The base liquid may be refined and/or synthetic oil, water, brine, or a water/oil emulsion. The drilling fluid 25d may further include solids dissolved or suspended in the base liquid, such as organophilic clay, lignite, and/or asphalt, thereby forming a mud.

[0029] The drilling fluid 25d may flow from the supply line 24 and into a bore of the pipe string 4s via the top drive 6. The drilling fluid 25d may flow down the pipe string 4s, through a bore of the BHA 4b, and exit the drill bit 8, where the fluid may circulate cuttings away from the bit and return the cuttings up an annulus 26 formed between an inner surface of the casing string 24 or wellbore 2 and an outer surface of the drill string 4. The returns 25r (drilling fluid 25d plus cuttings) may flow up the annulus 26, to the wellhead 16, and exit the wellhead through the flow cross of the PCA 1p. The returns 25r may continue through the return line 23. The returns 25r may then flow into the shale shaker 21 and be processed thereby to remove the

cuttings, thereby completing a cycle. As the drilling fluid 25d and returns 25r circulate, the drill bit 8 may be rotated 14m by the drilling motor 10 and lowered 14a by the traveling block 7c, thereby extending the wellbore 2 into the lower formation 18b. The pipe string 4s may be held rotationally stationary by the top drive 6 and inclination of the drill bit 8 by the motor 10 may cause drilling along a curved trajectory.

[0030] Figure 2 illustrates one method of operation of the stuck pipe warning system 3. Referring also to Figures 3A and 3B, at step 30, the stuck pipe warning system 3 may be manually initialized by analyzing historical data from similar wellbores drilled in the same or similar oilfields. The previously drilled wellbores may be selected based on having had stuck pipe incidents and the historical data may be analyzed to determine the root cause of each. Specific patterns in the historical data may be identified as leading indicators of stuck pipe. The leading indicators may include one or more parameters, such as torque, standpipe pressure, and hook load. The historical analysis may include reviewing deviations in the parameters from expected values determined by a model of the previously drilled wellbores.

[0031] From this analysis, allowable deviations of the parameters from the expected values may be determined. If the deviation is positive, it may be characterized as a maximum allowable deviation and if the deviation is negative, it may be characterized as a minimum allowable deviation. The historical data may also be analyzed to determine allowable rates of change of the parameters with respect to depth. The allowable deviations and rates of change may be determined for specific rig activities, such as rotary drilling, slide drilling, forward reaming (aka ream in), backward reaming, tripping of the drill string 4 into the wellbore 2, and tripping the drill string from the wellbore. Only some of the parameters may be applicable for certain rig activities.

[0032] The allowable deviations and rates of change may be selected from ranges varying between positive two and twenty-five percent and negative two and twenty-five percent depending on the parameter or rate of change of the parameter and the activity being performed. Specific values of the allowable deviations and

rates of change may be selected based upon parameters of the lower formation 18b, wellbore geometry, and parameters of the BHA 4b.

[0033] The historical analysis may further include assessing a stuck pipe risk threshold based on a cost-benefit analysis of the historical data and the type of well being drilled. For example, a higher threshold may be tolerated for a terrestrial wellbore as compared to a lower threshold for an offshore wellbore where the costs of stuck pipe may be far greater. The stuck pipe risk threshold may range between ten and fifty percent.

[0034] Alternatively, the historical analysis may be performed by a machine learning process, such as a neural network.

[0035] Once the allowable deviations and rates of change have been determined from the analysis of historical data, the allowable values may be provided to the PLC 15 for execution of operating steps 31-42.

[0036] Referring also to Figures 4A and 4B, at step 31, the PLC 15 may determine the rig activity that is about to be performed from configuration of the BHA 4b, whether the top drive 6 is being operated to rotate the drill string 4 or hold the drill string rotationally stationary, and/or whether the mud pump 19 is being operated to pump drilling fluid through the drill string. Once the PLC 15 has determined the activity, the PLC may form and select the location of sample windows for averaging the deviations and rates of changes. Averaging the deviations and rates of change may desensitize the stuck pipe warning system 3 to anomalies in the measured values and/or errors in the model.

[0037] As shown, each window has been sized at twenty-five feet (seven point six meters); however, the window size may be adjusted by the driller between a range of ten to fifty feet (three to fifteen point two meters). The location of the windows may be determined based on the activity to be performed. For forward activities, the windows may be above the current bit depth and for backward activities, the windows may be below the current bit depth. Once the activity has begun, the PLC 15 may refrain from steps 34-41 until enough measured

parameters have been collected to fill the windows. As the operating steps 31-42 are iterated by the PLC 15 during the activity, the PLC may move the sample windows with progression of the current depth.

[0038] Alternatively, the PLC 15 may prompt the driller to select the activity that is about to be performed.

[0039] Referring also to Figures 5A and 5B, at step 32, the PLC 15 may input the predicted values from the model. The model may only generate predicted values at a relatively low frequency, such as once per one hundred feet (thirty point five meters). The PLC 15 may operate the operating steps at a much higher frequency, such as between one iteration every five feet (one point five meters) and one iteration every one inch (twenty-five millimeters). The PLC 15 may utilize sets of two predicted values at depths straddling the current depth for each parameter to interpolate a predicted value for the current depth.

[0040] At step 33, the PLC 15 may input the measured parameters from the rig sensors, such as torque from the sensor of the top drive 6, standpipe pressure from the pressure sensor 22, and hook load from the detector (depicted by dashed line to crown block 7c). Referring also to Figure 6A, at step 34, the PLC 15 may calculate deviations of the measured parameters from the respective predicted values using the formula shown therein. At step 35, the PLC 15 may average the calculated deviations with previously calculated deviations in the current window.

[0041] Referring also to Figure 6B, at step 36, the PLC 15 may apply weighting factors to the average deviations to obtain alert levels. To apply the weighting system, the PLC 15 may divide the average deviations by the respective allowable deviations to obtain deviation ratios. If each deviation ratio is less than one, the PLC 15 may assign the respective deviation a zero alert level. If each deviation ratio is greater than or equal to one and less than or equal to three, the PLC 15 may assign the respective deviation an alert level equal to the respective ratio. If each deviation ratio is greater than three, the PLC 15 may assign the respective deviation an alert level of three. This weighting system may give deviations that exceed the respective allowable deviation by a large margin greater weight than

those that only slightly exceed the respective allowable deviation while further desensitizing the stuck pipe warning system 3 to anomalies in the measured values and/or errors in the model.

[0042] Referring also to Figure 6C, at step 37, in preparation for calculating the rates of change (ROCs), the PLC 15 may average the measured parameters with respective previously measured parameters in the current window. Still referring also to Figure 6C, at step 38, the PLC 15 may calculate rates of change of the average measured parameters in the current window from the respective average measured parameters in the previous window using the formula shown therein (see also Figure 4B). The rates of change calculations may not utilize the predicted values from the model, thereby further desensitizing the stuck pipe warning system 3 from errors in the model.

[0043] Referring also to Figure 6D, at step 39, the PLC 15 may apply weighting factors to the rates of change to obtain alert levels. To apply the weighting system, the PLC 15 may divide the rates of change by the respective allowable rates of change to obtain ROC ratios. If each ROC ratio is less than one, the PLC 15 may assign the respective rate of change a zero alert level. If each ROC ratio is greater than or equal to one and less than or equal to three, the PLC 15 may assign the respective rate of change an alert level equal to the respective ratio. If each ROC ratio is greater than three, the PLC 15 may assign the respective rate of change an alert level of three. This weighting system may give rates of change that exceed the respective allowable rates of change by a large margin greater weight than those that only slightly exceed the respective allowable rate of change.

[0044] Referring also to Figure 6E, at step 40, the PLC 15 may sum the alert levels of the deviations with the alert levels of the rates of change and divide by the maximum alert level to obtain the stuck pipe risk using the formula shown therein. The maximum alert level may simply be the maximum alert level for each deviation and rate of change (three as shown for each in Figures 6B and 6D) times the number of deviations and rates of change (four shown in Figures 3A and 3B for slide drilling), such as equaling twelve for slide drilling. Consolidation of the deviations and rates of change to one stuck pipe risk value may facilitate

comprehension of the risk by the driller.

[0045] At step 41, the PLC 15 may compare the stuck pipe risk to the risk threshold obtained from the historical analysis at step 30 and may alert the driller should the stuck pipe risk exceed the threshold. The alert may be audible and/or visible. The alert may include suggested remedial action, such as lowering bottom hole pressure, performing a cleanout operation, lessening weight on bit, and/or tripping the drill string 4 to reconfigure the BHA 4b. The PLC 15 may also display the stuck pipe risk as a plot on the driller's console (Figure 7).

[0046] At step 42, the PLC 15 may store the results in a database for further analysis. The storage may be especially useful if a stuck pipe event does occur. The PLC 15 may then return to step 32 and continue iteration in real time until the activity has been completed. Once the activity has been completed, the PLC 15 may return to step 31 for a further activity, such as rotary drilling.

[0047] Figure 8 illustrates rotary drilling of the wellbore 2 using the drilling system 1. Once the BHA 4b has reached the desired trajectory, a mode of the drilling system 1 may be shifted from slide drilling to rotary drilling by operation of the top drive 6 to rotate 14t the pipe string 4s, thereby negating the curvature effect of the motor 10 and straightening the drilling trajectory (aka corkscrew path). The PLC 15 may detect the shift to rotary drilling and return to step 31 for monitoring the stuck pipe risk during the rotary drilling of the wellbore 2.

[0048] Figure 9 illustrates tripping the drill string 4 from the wellbore 2. Once the wellbore 2 has been drilled to total depth, drilling may be halted by stopping rotation 14t of the pipe string 4s by the top drive 6, stopping lowering 14a of the traveling block 7t, stopping injection of the drilling fluid 25d, and removing weight from the drill bit 8. The drill string 4 may be supported from the rig floor 5f. The quill may be disconnected from the pipe string 4s and a pipe handler 6h of the top drive 6 operated in conjunction with tongs (not shown) and the traveling block 7t to disassemble and retrieve 14r the drill string 4 from the wellbore 2. The PLC 15 may detect the drilling stoppage and operation of the pipe handler 6h and return to step 31 for monitoring the stuck pipe risk during retrieval 14r of the drill string 4

from the wellbore (aka tripping out).

[0049] Figure 10 illustrates reaming of the wellbore using the drilling system. Once the (drilling) BHA 4b has been retrieved to the rig floor 5f, the BHA 4b may be disassembled and replaced by a reaming BHA. The reaming BHA may include the drill bit 8, a rotary steerable system (RSS) 12, and an underreamer 13. The reaming BHA members 8, 12, 13 may be interconnected, such as by threaded couplings. A downlink (not shown) may be added to the fluid handling system 1f for communication with a controller of the RSS 12.

[0050] The pipe string 4s may be connected to the reaming BHA and further assembly thereof used to deploy 14a the reaming BHA into the wellbore 2 (aka tripping in). The PLC 15 may detect operation of the pipe handler 6h and return to step 31 for monitoring the stuck pipe risk during deployment of the reaming BHA into the wellbore.

[0051] The RSS 12 may include a mandrel having threaded couplings formed at each longitudinal end thereof and a housing having an actuator and a plurality of levers spaced therearound, such as three spaced at one hundred twenty degree intervals. The housing may be supported from the mandrel by bearings such that the housing may remain rotationally stationary relative to the mandrel. The actuator may include a hydraulic pump driven by relative rotation between the housing and the mandrel and a piston connected to each lever, a cylinder keeping each piston, and a manifold selectively providing fluid communication between each piston and the pump for extension or retraction of the respective lever. The RSS controller may receive steering instructions from the PLC 15 and operate one or more of the levers to point the bit 8 along the instructed path.

[0052] Alternatively, the RSS 17 may be a push type. Alternatively, the RSS 17 may be used to slide drill and rotary drill the wellbore 2 instead of the steering motor 10.

[0053] The reaming BHA may be lowered 14a into the lower formation 18b until a heel of the wellbore 2 is reached. The quill may then be connected to the upper

end of the pipe string 4s, drilling fluid 25d injected through the pipe string and the reaming BHA and the top drive 6 operated to rotate the pipe string 4s. Arms of the underreamer may extend in response to injection of the drilling fluid through the reaming BHA and lowering 14a of the pipe string 4s may resume, thereby forward reaming the wellbore 2 (aka reaming in). The PLC 15 may detect the shift to forward reaming and return to step 31 for monitoring the stuck pipe risk during the reaming in of the wellbore 2.

[0054] Once the drill bit 8 reaches a toe of the wellbore 2, movement of the reaming BHA may be reversed to pull the reaming BHA along the wellbore, thereby backward reaming the wellbore (aka back reaming). The PLC 15 may detect the shift to backward reaming and return to step 31 for monitoring the stuck pipe risk during the back reaming of the wellbore 2.

[0055] Once the wellbore 2 has been back reamed to the heel thereof, the reaming may be halted by stopping rotation 14t of the pipe string 4s by the top drive 6, stopping raising 14r of the traveling block 7t, and stopping injection of the drilling fluid 25d. The pipe string 4s may be supported from the rig floor 5f. The quill may be disconnected from the pipe string 4s and the pipe handler 6h operated in conjunction with tongs (not shown) and the traveling block 7t to disassemble and retrieve 14r the pipe string 4s and reaming BHA from the wellbore 2. The PLC 15 may detect the reaming stoppage and operation of the pipe handler 6h and return to step 31 for monitoring the stuck pipe risk during retrieval 14r of the pipe string 4s and reaming BHA from the wellbore 2.

[0056] Alternatively, the wellbore 2 may only be forward reamed or reversed reamed but not both.

[0057] Figure 11 illustrates reaming a liner string 50 into the wellbore 2 using the drilling system 1. Once the wellbore 2 has been reamed, the liner string 50 may be assembled using the drilling rig 1r and a work string used to deploy the liner string into the wellbore 2. The liner string 50 may include a polished bore receptacle (PBR) 51, a packer 52, a hanger 53, a mandrel 54 for carrying the hanger and packer, joints of liner 55, a float collar 56, and a reamer shoe 57. The mandrel 54,

liner joints 55, float collar 56, and reamer shoe 57 may be interconnected, such as by threaded couplings. The work string may include the pipe string 4s and a liner deployment assembly (LDA) 58. An upper end of the LDA 58 may be connected to a lower end of the pipe string 4s, such as by threaded couplings. The LDA 58 may also be releasably connected to the mandrel 54.

[0058] The liner string 50 may be lowered 14a into the wellbore 2 until the reamer shoe 57 reaches the lower formation 18b. The quill may then be connected to the upper end of the pipe string 4s, drilling fluid 25d injected through the work string and the liner string 50 and the top drive 6 operated to rotate 14t the work string and the liner string. Lowering 14a of the liner string 50 may resume, thereby reaming the liner string into the wellbore 2. The PLC 15 may detect the shift to liner reaming and return to step 31 for monitoring the stuck pipe risk during the reaming of the liner string 50 into the wellbore 2. The PLC 15 may utilize the allowable deviations and rates of change for reaming by the reaming BHA for reaming of the liner string.

[0059] Alternatively, separate allowable deviations and rates of change may be determined for the liner reaming during the analysis of the historical data.

[0060] Once the reamer shoe 57 reaches a depth in the wellbore 2 adjacent to the toe, a setting plug (not shown), such as a ball, may be launched and pumped down the pipe string 4s to the LDA 58. The setting plug may land in a seat of the LDA 58 and continued pumping may increase pressure in the pipe string 4s and an upper bore of the LDA 58 until the liner hanger 53 is set and the LDA is released from the liner string 50. The setting plug may then be released from the seat and stowed in a catcher of the LDA 58. A cement pump (not shown) may be operated to pump cement slurry (not shown) from a mixer (not shown) and into the pipe string 4s via a cement head (not shown). Once a desired quantity of cement slurry has been injected into the pipe string 4s, the cement head may be operated to launch a cementing plug, such as a dart (not shown).

[0061] The mud pump 19 may then be operated to pump chaser fluid (not shown) into the pipe string 4s, thereby driving the dart and cement slurry through

the pipe string and into a bore of the liner string 50 until the dart seats in a wiper plug (not shown) of the LDA 58. Continued pumping of the chaser fluid may increase pressure to release the wiper plug from the LDA 58 and drive the cement slurry, wiper plug, and dart, down the liner string bore. The cement slurry may be driven through the float collar 56 and reamer shoe 57 and into the annulus until the wiper plug bumps the float collar. Pumping of the chaser fluid may then cease and the float collar 56 may close to prevent back flow of the cement slurry into the liner string bore. The LDA 58 may then be operated to set the packer 52 by articulation of the pipe string 4s. The work string may then be retrieved to the rig 1r and the drilling system 1 dispatched from the well site.

[0062] Alternatively, the stuck pipe warning system 3 may be used to run a casing or liner string into the wellbore 2 instead of reaming the liner string 50. Alternatively, the stuck pipe warning system 3 may be used to drill a casing or liner string into the lower formation 18 instead of slide and rotary drilling the lower formation. Alternatively, the stuck pipe warning system 3 may be used in a workover or intervention operation in the wellbore 2.

[0063] Figure 12 illustrates an alternative embodiment of the stuck pipe warning system. In this embodiment, the predicted values may be calculated from the measured parameters using commercially available engineering software, such as Weatherford's OneSync Monitoring™. A continuous time-based prediction for the predicted values may be generated from real-time measured values for each parameter, such as torque, standpipe pressure, and hook load while accounting for changes in flow rate, weight on bit, revolutions per minute, and rig activity.

[0064] At step 60, the stuck pipe warning system may be manually initialized from the historical analysis in the same manner as step 30, discussed above. From the historical analysis, allowable deviations of the measured parameters from the expected values may be determined. The historical data may also be analyzed to determine allowable rates of change of the parameters with respect to time using the relationship between the bit velocity, depth, and time, where bit velocity multiplied by time equals a depth. The allowable deviations and rates of change may be determined for specific rig activities, such as rotary drilling, slide drilling,

forward reaming (aka ream in), backward reaming, tripping of the drill string 4 into the wellbore 2, and tripping the drill string 4 from the wellbore 2. Only some of the parameters may be applicable for certain rig activities.

[0065] The allowable deviations and rates of change may be selected in the same manner as discussed above, with respect to step 30. Alternatively, the allowable rates of change of the parameters may be modified to accommodate for changes in an input parameter such as rotation speed, flow rate, or revolutions per minute. The allowable rates of change may be modified by multiplying by an average value of a selected input parameter over a short period of time (e.g. fifteen seconds) and dividing by an average value of the same input parameter over a longer period of time (e.g. one minute).

[0066] The stuck pipe risk threshold may be assessed in the same manner as discussed above, with respect to step 30.

[0067] Once the allowable deviations and rates of change have been determined from the analysis of the historical data, the allowable values may be provided to the PLC 15 for execution of the operating steps 61-72.

[0068] At step 61, the PLC 15 may determine the rig activity that is about to be performed, in the same manner as step 31.

[0069] Alternatively, the PLC 15 may prompt the driller to select the activity that is about to be performed.

[0070] At step 62, the PLC may input the measured parameters from the rig sensors, such as torque from the sensor of the top drive 6, standpipe pressure from the pressure sensor 22, and hook load from the detector (depicted by dashed line to crown block 7c) into the OneSync Monitoring™ software. At step 63, the OneSync Monitoring™ software may calculate predicted values from the respective measured parameters. The PLC 15 may input the predicted values from the OneSync Monitoring™ software.

[0071] Steps 64-72 may be carried out in the same manner as steps 34-42

discussed above. The PLC 15 may then return to step 62 and continue iteration in real time until the activity has been completed. Once the activity has been completed, the PLC 15 may return to step 61 for a further activity, such as rotary drilling.

[0072] The stuck pipe warning system of Figure 12 may be operated during wellbore operations such as rotary drilling, slide drilling, forward reaming (aka ream in), backward reaming, tripping of the drill string 4 into the wellbore 2, and tripping the drill string 4 from the wellbore 2, in the same manner discussed above with respect to the stuck pipe warning system of Figure 2, as shown in Figures 1 and 8-11.

[0073] While the foregoing is directed to embodiments of the present disclosure, other and further embodiments of the disclosure may be devised without departing from the basic scope thereof, and the scope of the invention is determined by the claims that follow.

Claims:

1. A method of performing an operation in a wellbore, comprising:
performing the operation in the wellbore from a rig; and
while performing the operation, repeatedly:
 - inputting one or more predicted values from a model of the wellbore;
 - inputting one or more measured parameters from one or more sensors of the rig;
 - calculating a deviation of each measured parameter from a respective predicted value;
 - applying a first weighting factor to each calculated deviation to obtain a respective alert level;
 - calculating a rate of change of each measured parameter from a parameter previously measured by the respective sensor;
 - applying a second weighting factor to each calculated rate of change to obtain a respective alert level; and
 - adding the alert levels and dividing the sum thereof by a maximum alert level to obtain a stuck pipe risk.
2. The method of claim 1, wherein:
 - the method further comprises analyzing historical data from previously drilled wellbores to obtain one or more allowable deviations and one or more allowable rates of change, and
 - the weighting factors are applied using the respective allowable deviations and allowable rates of change.
3. The method of claim 2, wherein:
 - each of the allowable deviations range between an absolute value of 2-25%, and
 - each of the allowable rates of change range between an absolute value of 2-25%.

4. The method of claim 2, wherein:
 - the parameters comprise hook load and standpipe pressure,
 - each of the allowable deviations and allowable rates of change for hook load are negative, and
 - each of the allowable deviations and allowable rates of change for standpipe pressure are positive.
5. The method of claim 2, wherein:
 - the historical data is further analyzed to obtain a risk threshold, and
 - the method further comprises:
 - comparing the stuck pipe risk to the risk threshold; and
 - alerting a driller if the stuck pipe risk exceeds the risk threshold.
6. The method of claim 2, wherein:
 - a deviation ratio is calculated to apply the weighting factor to each calculated deviation,
 - a rate of change ratio is calculated to apply the weighting factor to each calculated rate of change,
 - a weighting factor of 0 is assigned for each alert level if the respective ratio is less than 1,
 - a weighting factor for each alert level equal to the respective ratio is assigned if the respective ratio is greater than or equal to 1 and less than or equal to 3, and
 - a weighting factor of 3 is assigned for each alert level if the respective ratio is greater than 3.
7. The method of claim 1, wherein:
 - the method further comprises averaging each calculated deviation with respective previously calculated deviations in a current sample window;
 - each weighting factor is applied to the respective average calculated deviation.

8. The method of claim 7, wherein:
 - each previously measured parameter is an average of respective previously measured parameters in a previous sample window,
 - the method further comprises averaging each measured parameter with respective previously measured parameters in the current sample window, and
 - each rate of change is calculated using the respective averages of the respective measured parameters in the sample windows.
9. The method of claim 1, further comprising displaying a plot of the stuck pipe risk on a driller's console.
10. The method of claim 1, further comprising interpolating the predicted values to a current depth of the downhole operation.
11. The method of claim 1, wherein:
 - the rig is a drilling rig, and
 - the downhole operation is drilling the wellbore.
12. The method of claim 11, wherein:
 - the downhole operation is slide drilling, and
 - the measured parameters comprise hook load and standpipe pressure.
13. The method of claim 11, wherein:
 - the downhole operation is rotary drilling, and
 - the measured parameters comprise hook load, torque, and standpipe pressure.
14. The method of claim 1, wherein:
 - the rig is a drilling rig,
 - the downhole operation is tripping a drill string from or into the wellbore, and
 - the measured parameters comprise hook load.

15. The method of claim 1, wherein:
 - the rig is a drilling rig, and
 - the downhole operation is reaming in or back reaming the wellbore, and
 - the measured parameters comprise hook load, torque, and standpipe pressure.
16. The method of claim 1, wherein:
 - the rig is a drilling rig, and
 - the downhole operation is running a casing or liner string into the wellbore.
17. The method of claim 1, further comprising calculating the one or more predicted values for the model from the one or more measured parameters.
18. The method of claim 2, further comprising modifying the one or more rates of change to account for changes in rotation speed, flow rate, or revolutions per minute during the operation.
19. A method of performing an operation in a wellbore from a rig, comprising:
 - measuring one or more parameters using one or more sensors of the rig;
 - obtaining one or more predicted values from a model of the wellbore;
 - calculating a deviation of each measured parameter from a respective predicted value;
 - applying a first weighting factor to each calculated deviation to obtain a respective first alert level;
 - calculating a rate of change of each measured parameter from a parameter previously measured by the respective sensor;
 - applying a second weighting factor to each calculated rate of change to obtain a respective second alert level; and
 - adding the first and second alert levels and dividing the sum thereof by a maximum alert level to obtain a stuck pipe risk.

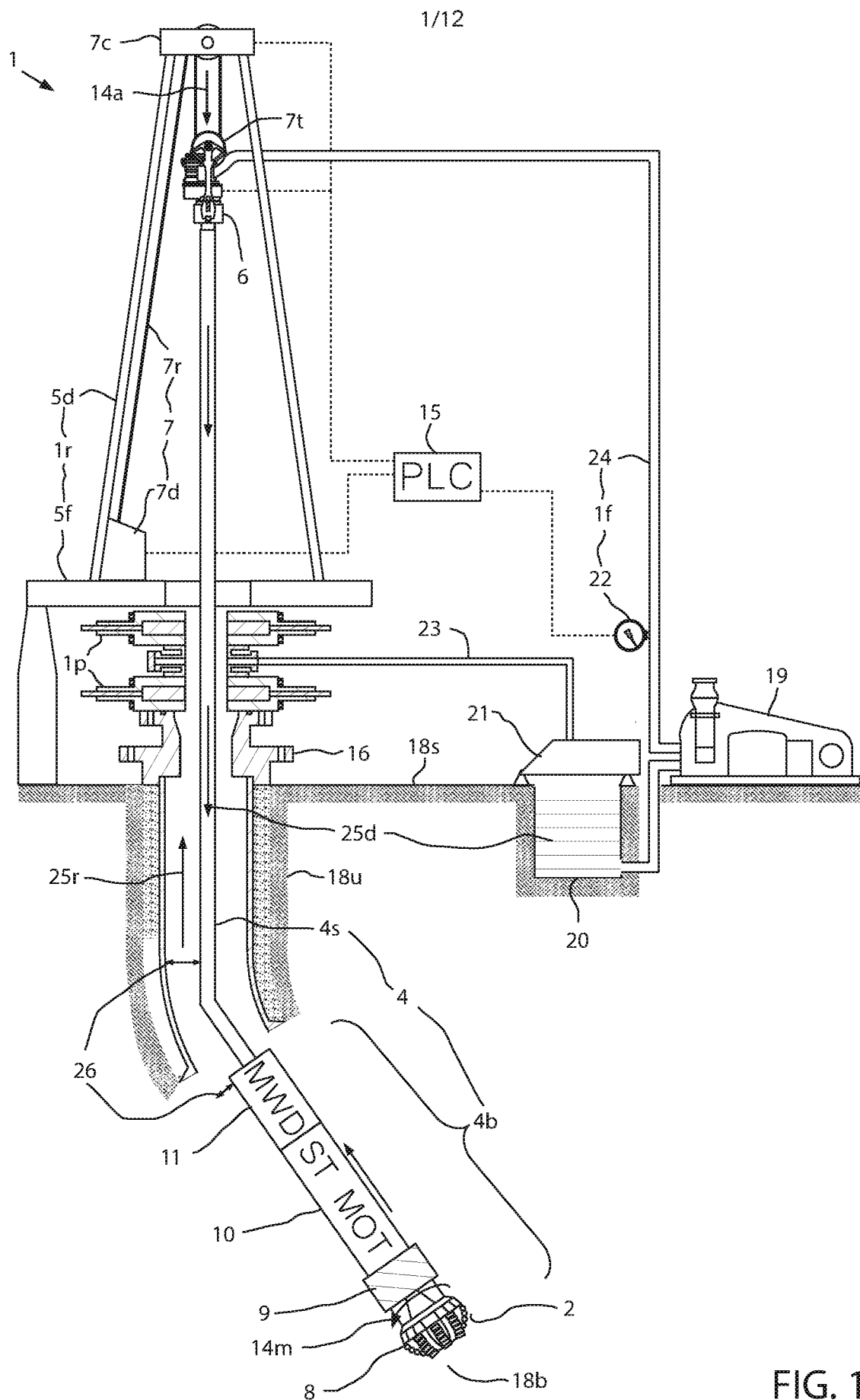
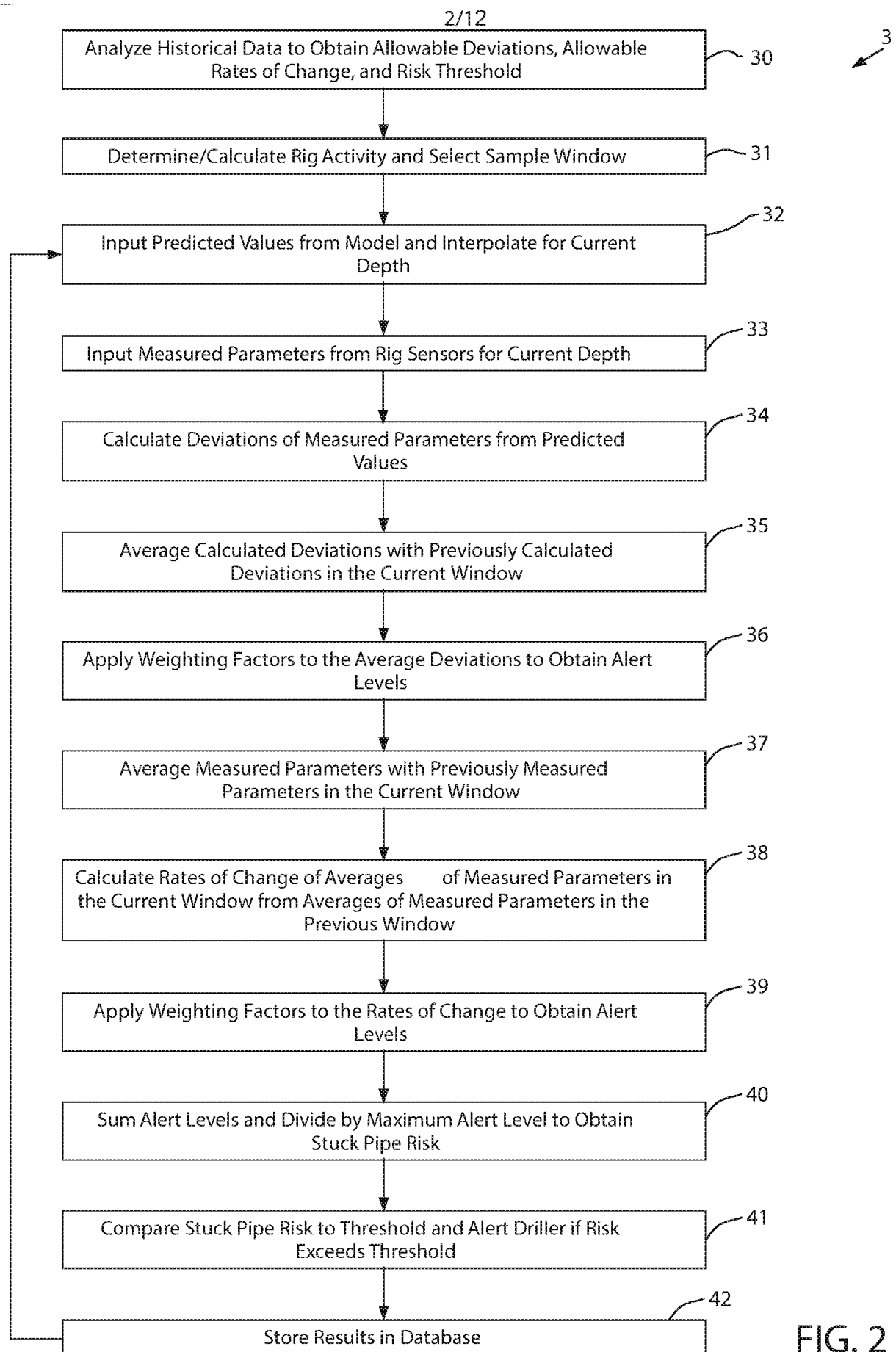


FIG. 1



3/12

Activity	Allowable Hook Load (HL) Deviation	Allowable Torque (TQ) Deviation	Allowable Standpipe Pressure (SPP) Deviation
Rotary Drill	-2% to -25%	2% to 25%	2% to 25%
Slide Drill	-2% to -25%	N/A	2% to 25%
Ream In	-2% to -25%	2% to 25%	2% to 25%
Back Ream	2% to 25%	2% to 25%	2% to 25%
Trip In	-2% to -25%	N/A	N/A
Trip Out	2% to 25%	N/A	N/A

FIG. 3A



30

Activity	Allowable HL Rate of Change	Allowable TQ Rate of Change	Allowable SPP Rate of Change
Rotary Drill	-2% to -25%	2% to 25%	2% to 25%
Slide Drill	-2% to -25%	N/A	2% to 25%
Ream In	-2% to -25%	2% to 25%	2% to 25%
Back Ream	2% to 25%	2% to 25%	2% to 25%
Trip In	-2% to -25%	N/A	N/A
Trip Out	2% to 25%	N/A	N/A

FIG. 3B

4/12

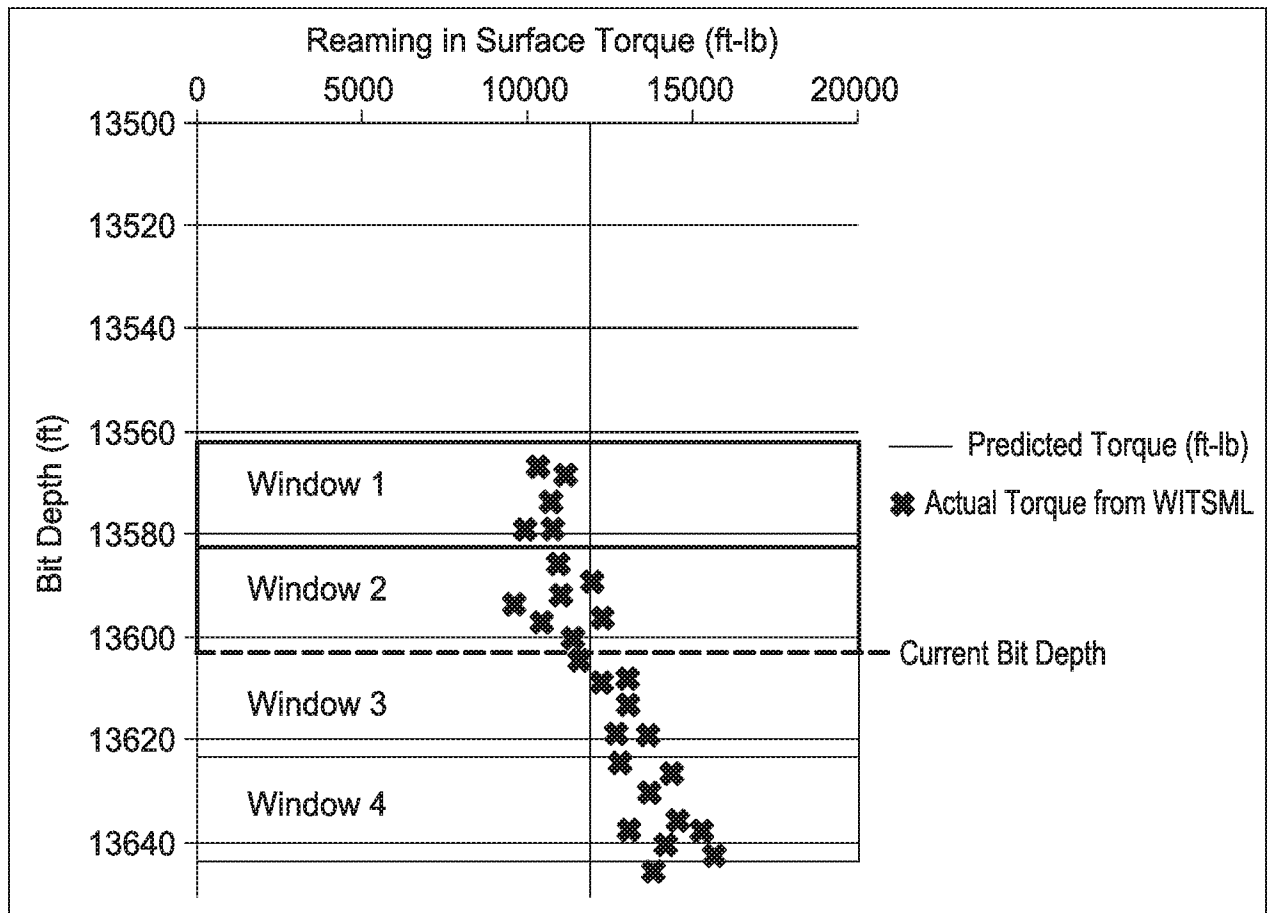


FIG. 4A

Rig Activity	Maximum Allowable Deviation	Rate of Change
Slide Drill	[Deviation_Window 2]	$\frac{[MVG_AVG_Window\ 2] - [MVG_AVG_Window\ 1]}{[MVG_AVG_Window\ 1]}$
Rotary Drill	[Deviation_Window 2]	$\frac{[MVG_AVG_Window\ 2] - [MVG_AVG_Window\ 1]}{[MVG_AVG_Window\ 1]}$
Ream In	[Deviation_Window 2]	$\frac{[MVG_AVG_Window\ 2] - [MVG_AVG_Window\ 1]}{[MVG_AVG_Window\ 1]}$
Back Ream	[Deviation_Window 3]	$\frac{[MVG_AVG_Window\ 4] - [MVG_AVG_Window\ 3]}{[MVG_AVG_Window\ 3]}$
Trip In	[Deviation_Window 2]	$\frac{[MVG_AVG_Window\ 2] - [MVG_AVG_Window\ 1]}{[MVG_AVG_Window\ 1]}$
Trip Out	[Deviation_Window 3]	$\frac{[MVG_AVG_Window\ 4] - [MVG_AVG_Window\ 3]}{[MVG_AVG_Window\ 3]}$

FIG. 4B

5/12

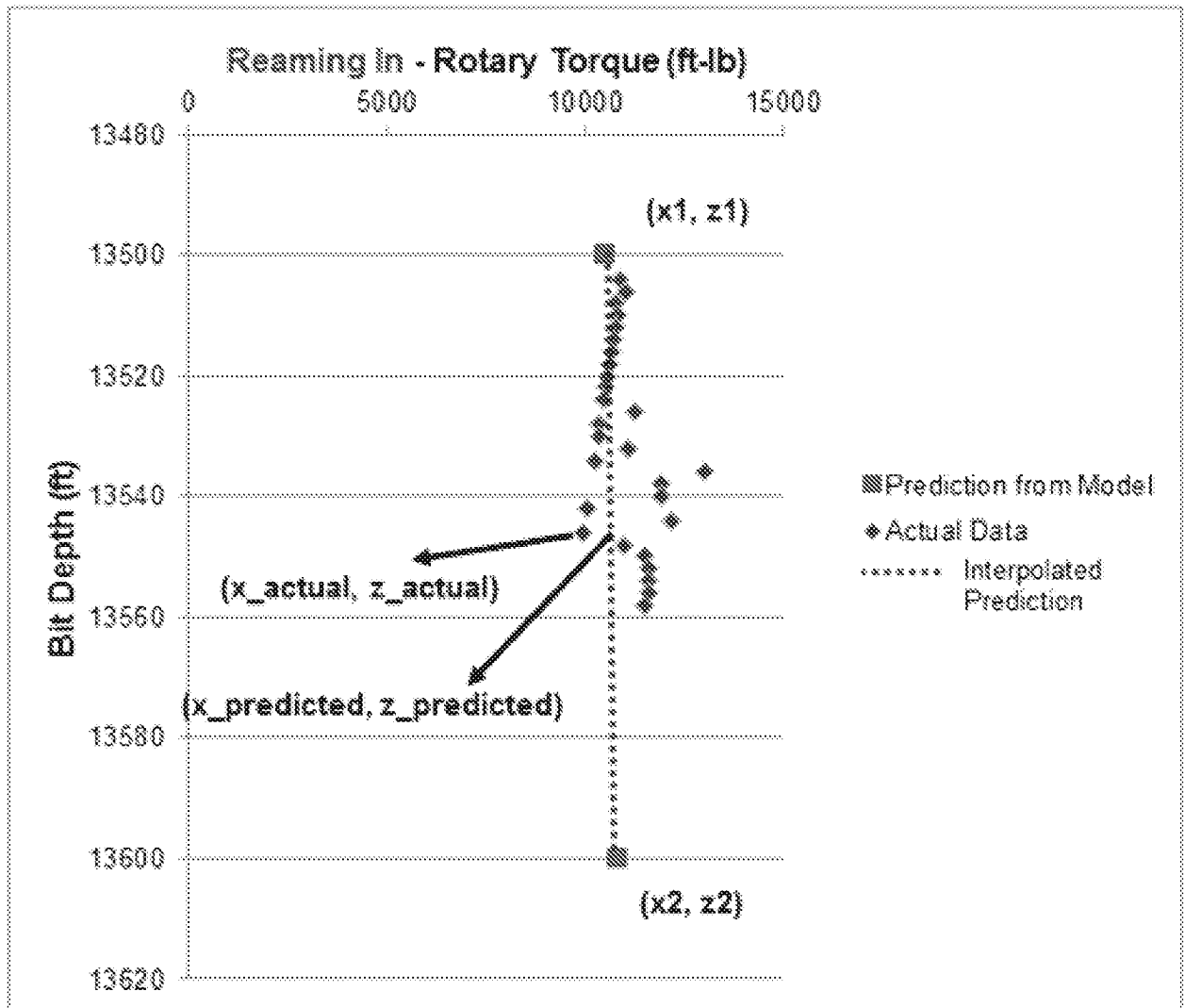


FIG. 5A

32, 33

$$x_{\text{predicted}} = x_1 + \left(\frac{x_2 - x_1}{z_2 - z_1} \right) z_{\text{actual}}$$

where $z_1 < z_{\text{actual}} < z_2$

FIG. 5B

6/12

34

$$Deviation = \left(\frac{x_{actual} - x_{predicted}}{x_{predicted}} \right) \times 100$$

FIG. 6A

36

(Calculated Deviation) / (Allowable)	Less than 1	Between 1 and 3	Greater than 3
Alert Level	0	(Calculated Deviation) / (Allowable)	3

FIG. 6B

37, 38

$$ROC = \frac{MVG \text{ AVG Window } 2 - MVG \text{ AVG Window } 1}{MVG \text{ AVG Window } 1} \times 100$$

FIG. 6C

39

(Calculated ROC) / (Allowable)	Less than 1	Between 1 and 3	Greater than 3
Alert Level	0	(Calculated ROC) / (Allowable)	3

FIG. 6D

40

$$Stuck \text{ Pipe Risk} = \frac{\text{Sum of all Alert Levels}}{\text{Maximum Alert Level}} \times 100$$

FIG. 6E

7/12

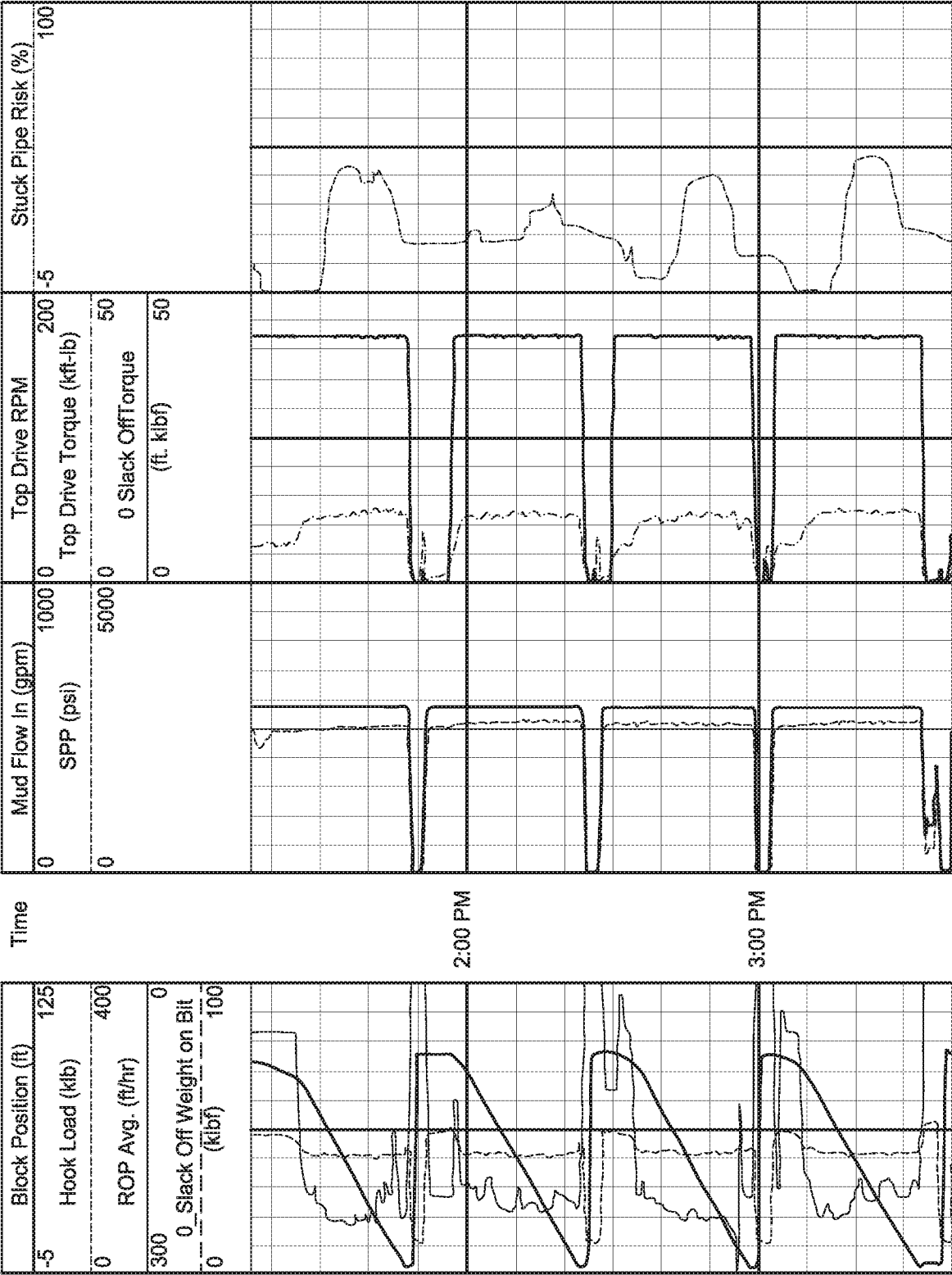


FIG. 7

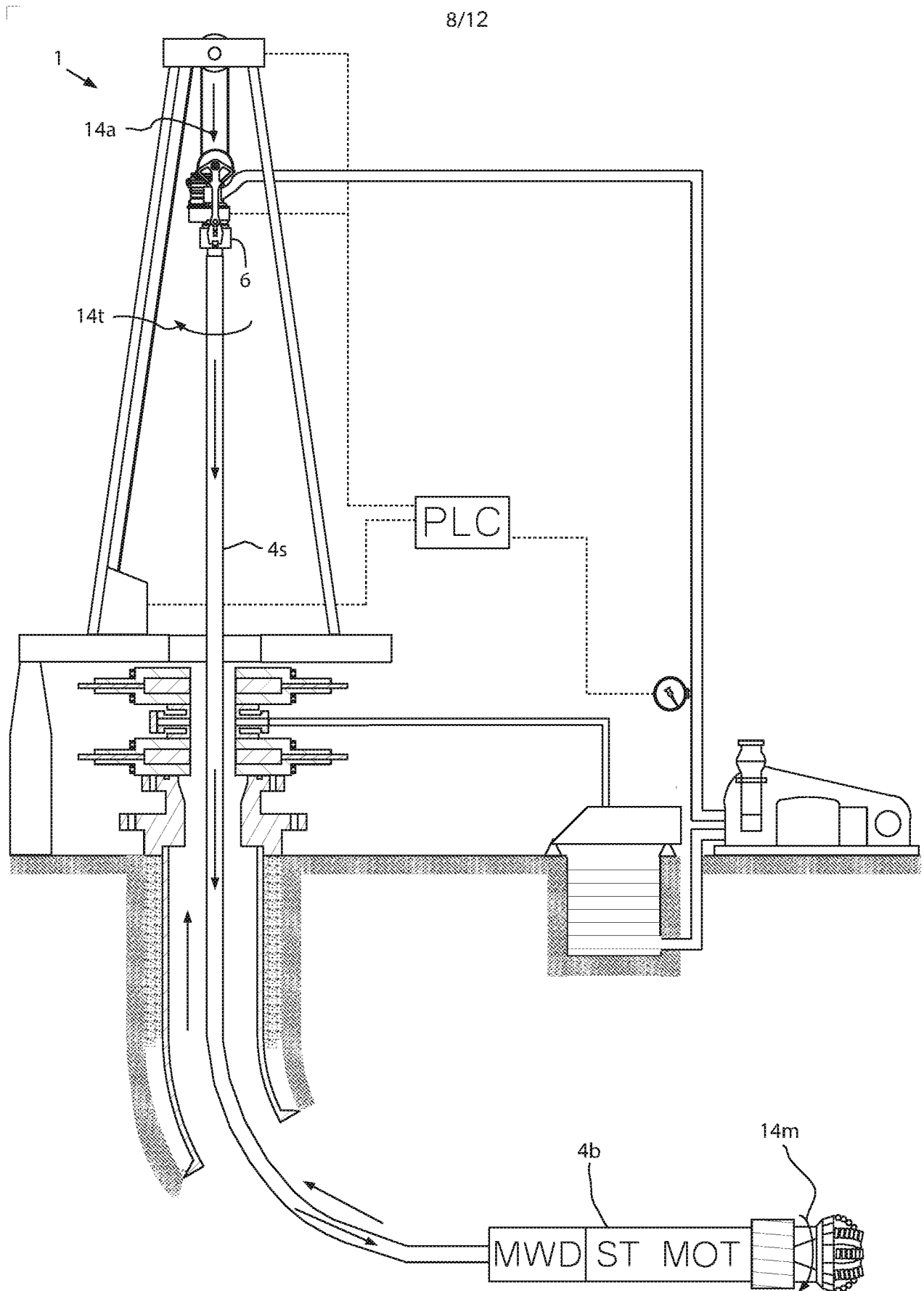


FIG. 8

9/12

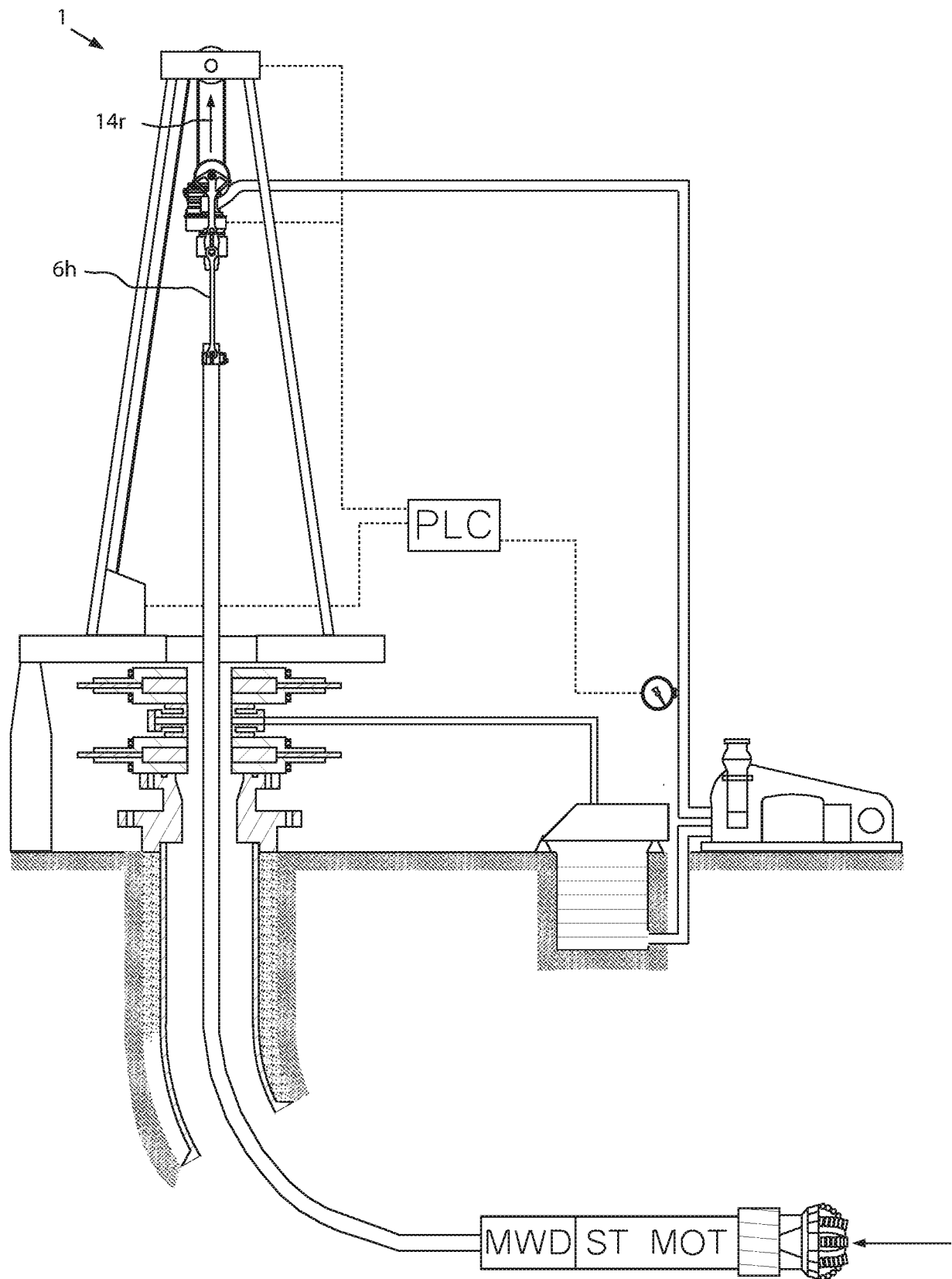


FIG. 9

10/12

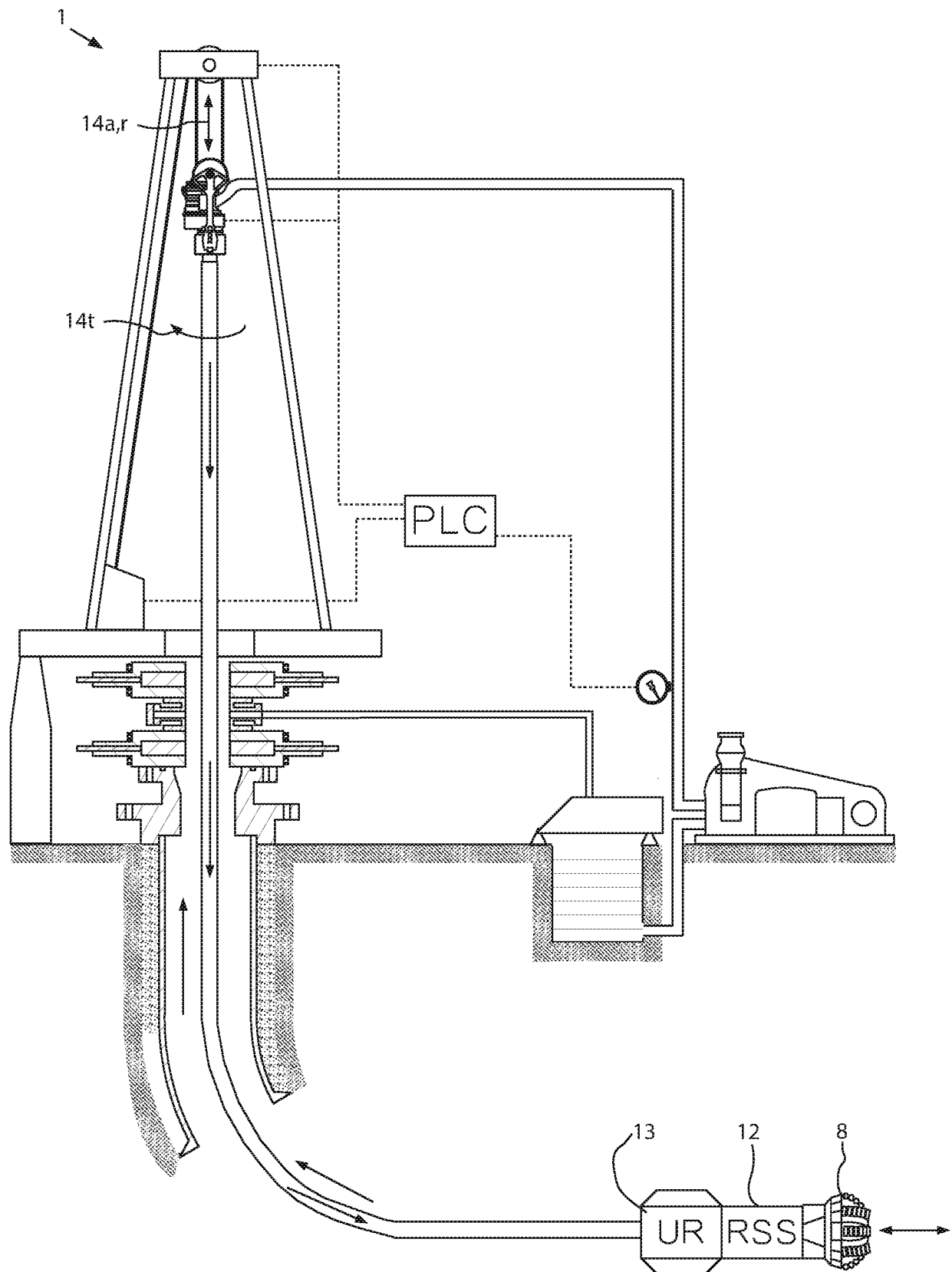


FIG. 10

11/12

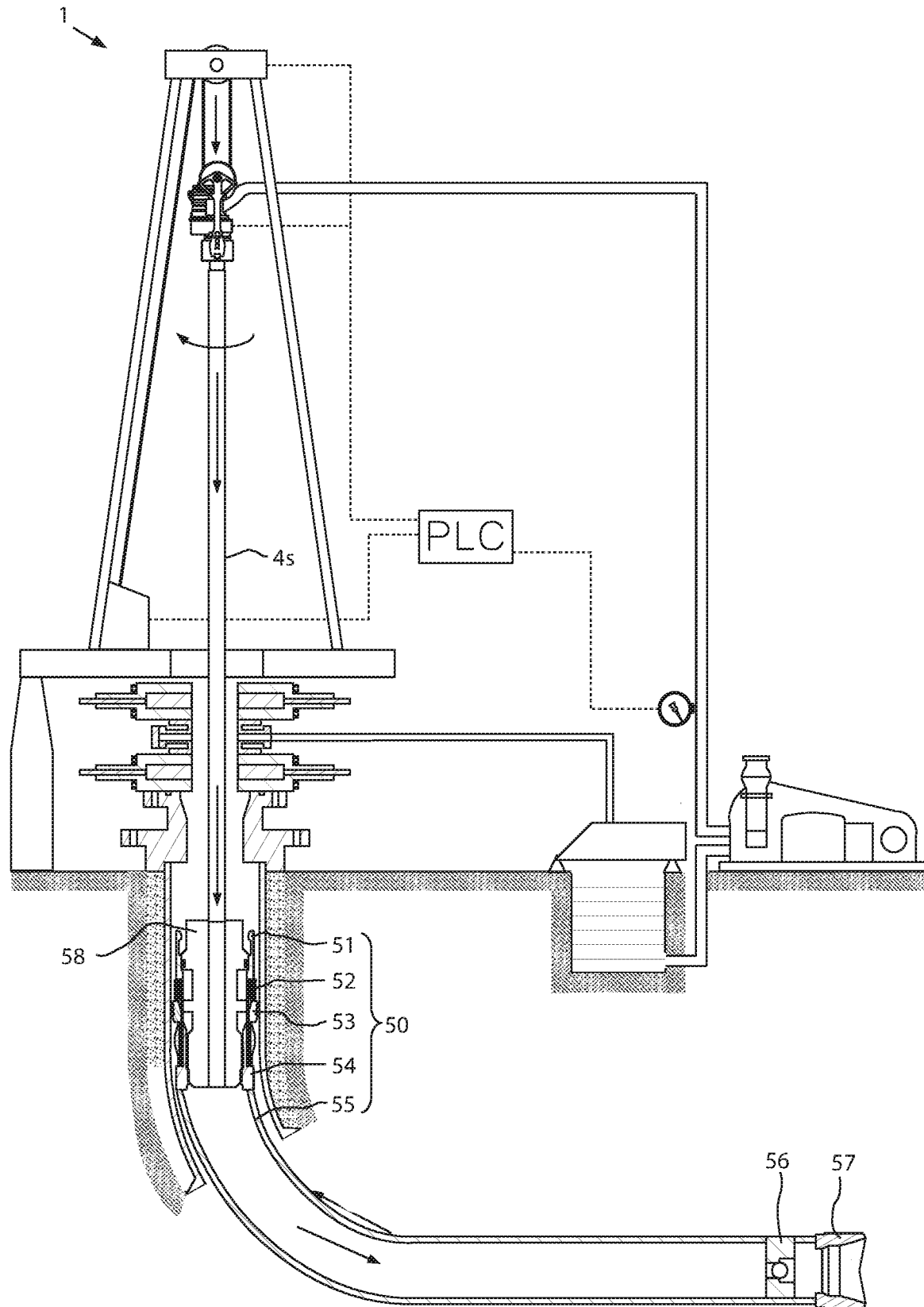


FIG. 11

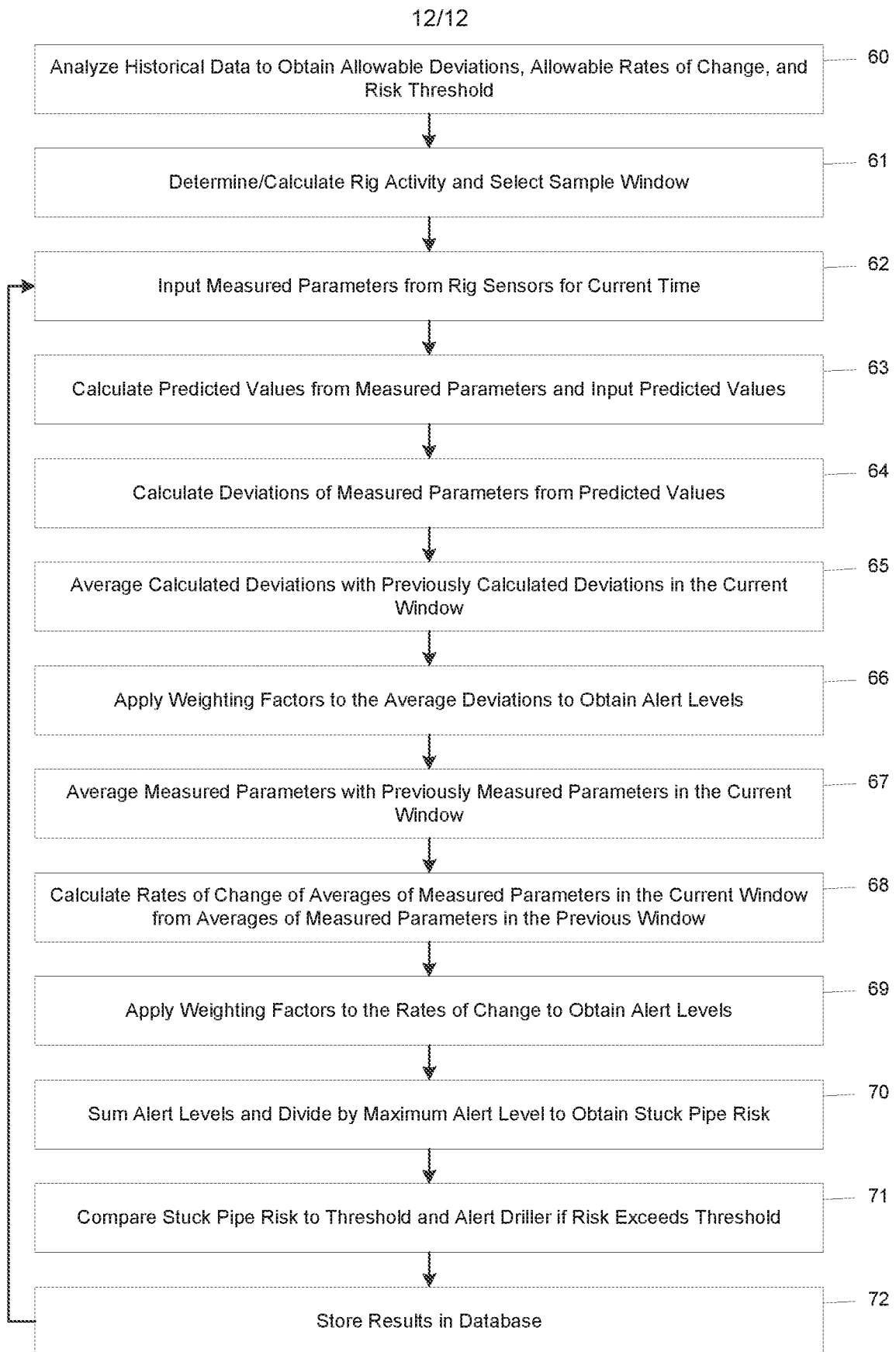


FIG. 12

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2016/037842

A. CLASSIFICATION OF SUBJECT MATTER
INV. E21B44/00
ADD.

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

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B

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

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

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 2015/134257 A1 (ERGE ONEY [US] ET AL) 14 May 2015 (2015-05-14) paragraphs [0024] - [0036], [0053], [0054]; claims 4,5	1-19
T	----- Kent Salminen ET AL: "IADC/SPE-178888-MS Stuck Pipe Prediction Using Automated Real-Time Modeling and Data Analysis", IADC / SPE Drilling Conference and Exhibition 2016, 3 March 2016 (2016-03-03), XP055297477, Retrieved from the Internet: URL:https://www.onepetro.org/download/conf erence-paper/SPE-178888-MS?id=conference-p aper/SPE-178888-MS [retrieved on 2016-08-24] ----- -/-	1-19



Further documents are listed in the continuation of Box C.



See patent family annex.

* Special categories of cited documents :

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

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

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

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

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search

25 August 2016

Date of mailing of the international search report

21/09/2016

Name and mailing address of the ISA/

European Patent Office, P.B. 5818 Patentlaan 2
NL - 2280 HV Rijswijk
Tel. (+31-70) 340-2040,
Fax: (+31-70) 340-3016

Authorized officer

Beran, Jiri

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2016/037842

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	WO 2015/060865 A1 (LANDMARK GRAPHICS CORP [US]) 30 April 2015 (2015-04-30) paragraphs [0022], [0023] -----	1-19
A	US 2014/122047 A1 (SALDIVAR JUAN LUIS [US] ET AL) 1 May 2014 (2014-05-01) paragraphs [0024] - [0032] -----	1-19
A	WO 2013/066746 A1 (LANDMARK GRAPHICS CORP [US]) 10 May 2013 (2013-05-10) paragraphs [0032] - [0038], [0045] - [0048]; figures 2,5,6 -----	1-19
A	US 6 401 838 B1 (REZMER-COOPER IAIN [US]) 11 June 2002 (2002-06-11) column 5, line 7 - column 6, line 46; figure 8B -----	1-19
A	WO 03/089758 A1 (HUTCHINSON MARK W [US]) 30 October 2003 (2003-10-30) paragraphs [0040] - [0045] -----	1-19
A	US 2014/077963 A1 (DANKERS STEPHAN [DE] ET AL) 20 March 2014 (2014-03-20) paragraphs [0032] - [0045]; figures 2,3 -----	1-19

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No

PCT/US2016/037842

Patent document cited in search report	Publication date	Patent family member(s)	Publication date
US 2015134257 A1	14-05-2015	AU 2014348760 A1 CA 2930541 A1 US 2015134257 A1 WO 2015073489 A1	02-06-2016 21-05-2015 14-05-2015 21-05-2015
WO 2015060865 A1	30-04-2015	AU 2013403353 A1 CA 2925113 A1 DE 112013007532 T5 GB 2534729 A SG 11201602213R A US 2016239754 A1 WO 2015060865 A1	14-04-2016 30-04-2015 07-07-2016 03-08-2016 30-05-2016 18-08-2016 30-04-2015
US 2014122047 A1	01-05-2014	NONE	
WO 2013066746 A1	10-05-2013	AR 088612 A1 AU 2012332905 A1 CA 2852765 A1 CN 104024572 A EP 2773848 A1 US 2014110167 A1 WO 2013066746 A1	25-06-2014 29-05-2014 10-05-2013 03-09-2014 10-09-2014 24-04-2014 10-05-2013
US 6401838 B1	11-06-2002	GB 2372129 A US 6401838 B1	14-08-2002 11-06-2002
WO 03089758 A1	30-10-2003	AU 2003223424 A1 AU 2003224831 A1 AU 2003230798 A1 CA 2482912 A1 CA 2482922 A1 CA 2482931 A1 EA 200601067 A1 EA 200601068 A1 EA 200601069 A1 EA 200601070 A1 EP 1502003 A2 EP 1502004 A1 EP 1502005 A1 US 2005087367 A1 WO 03089751 A2 WO 03089758 A1 WO 03089759 A1	03-11-2003 03-11-2003 03-11-2003 30-10-2003 30-10-2003 30-10-2003 27-10-2006 27-10-2006 27-10-2006 27-10-2006 02-02-2005 02-02-2005 02-02-2005 28-04-2005 30-10-2003 30-10-2003 30-10-2003
US 2014077963 A1	20-03-2014	GB 2525316 A US 2014077963 A1 WO 2014043467 A1	21-10-2015 20-03-2014 20-03-2014