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(57) Abstract: A disclosed drilling system includes a drill string assembly having subsystem inputs that control ROP and other performance parameters; and a processing system that provides automated uncertainty mitigation of a model for controlling the subsystem inputs. The drilling string assembly may include a BHA subsystem and a drill string that connects the BHA to a drilling rig subsystem and a fluid circulation subsystem. The processing system operates by: obtaining a drilling system model having interaction states representing how each subsystem input impacts the subsystem; characterizing an uncertainty for each interaction state; evaluating an influence of each interaction state's uncertainty on the performance parameters; calculating a net benefit for mitigating said model uncertainties; automatically mitigating said one or more model uncertainties when the net benefit exceeds a threshold, thereby improving the model of the drilling system; and controlling the subsystem inputs based on the model.

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DIRECTIONAL DRILLING WITH
AUTOMATIC UNCERTAINTY MITIGATION

BACKGROUND

Directional drilling is the process of steering a drill string, and hence the borehole. It can be achieved with a variety of drill string steering mechanisms, e.g., whipstocks, mud motors with bent-housings, jetting bits, adjustable gauge stabilizers, and rotary steering systems (RSS). Each of these mechanisms employs side force, bit tilt angle, or some combination thereof, to steer the drill string's forward and rotary motion. They may be used to avoid obstacles and reach desired targets, both of which may take various forms. For example a target may be specified in terms of an entry point to a formation, together with a desired entry vector. Both the entry point and vector may be specified as ranges or accompanied by acceptable tolerances. Some boreholes may even be associated with a series of such entry points and vectors.

Drillers generally employ careful trajectory planning not only to ensure that targets are reached and obstacles avoided, but also to limit curvature and tortuosity of the borehole. Such limits are needed to prevent the drill string and other tubulars from getting stuck, to avoid excessive friction, and to minimize casing wear.

Trajectory planning is generally subject to information uncertainty from a number of sources. For example, the drill string assembly continuously encounters formations whose precise properties are often not known in advance, but which affect the operation of the bit, or more precisely, affect the operating parameter ranges that induce bit whirl, stick-slip, vibration, and other undesirable behaviors, as well as affecting the relationship between those parameters and the rate of penetration ("ROP") or other measures of drilling performance. The drilling system model used to predict such behaviors might be mismatched with the physical drill string assembly. The formation heterogeneity may also be uncertain, as well as the precise positions of the formation boundaries and any detected formation anomalies. The operating parameters themselves may not be precisely known (e.g., rotations per minute (RPM), torque, hook load, weight on bit (WOB), downhole pressure, drilling fluid flow rate), whether due to inaccuracies in the control mechanisms or sensor noise. The steering mechanism may suffer from bit walk or other steering inaccuracies.

When faced with such uncertainties, drillers are often forced to adopt a conservative approach or suffer the consequences. Fortunately, many of the uncertainties can be reduced
and many drillers may choose to do so to achieve better drilling performance while maintaining the same safety margin. However, such uncertainty reduction comes at a cost that may be unjustifiable in view of the achievable performance gains, making it difficult for drillers to determine when and how to undertake uncertainty mitigation.

BRIEF DESCRIPTION OF THE DRAWINGS

Accordingly, there are disclosed herein directional drilling systems and methods employing stochastic path optimization of the operating parameters for drilling. In the drawings:

Fig. 1 is a schematic diagram of an illustrative well drilling environment.
Fig. 2 is a function-block diagram of a logging while drilling (LWD) system.
Figs. 3A-3D schematically illustrate various forms of drilling operation uncertainty.
Fig. 4 is a flow diagram of an illustrative directional drilling method.

It should be understood, however, that the specific embodiments given in the drawings and detailed description thereto do not limit the disclosure. On the contrary, they provide the foundation for one of ordinary skill to discern the alternative forms, equivalents, and modifications that are encompassed together with one or more of the given embodiments in the scope of the appended claims.

DETAILED DESCRIPTION

To provide context and facilitate understanding of the present disclosure, Fig. 1 shows an illustrative drilling environment, in which a drilling rig subsystem having a platform 102 supporting a derrick 104 with a traveling block 106 and motors for raising and lowering a drill string 108. A top-drive motor 110 supports and turns the drill string 108 as it is lowered into the borehole 112. The drill string's rotation, alone or in combination with the operation of a downhole motor, drives the drill bit 114 to extend the borehole. The drill bit 114 is one component of a bottomhole assembly (BHA) subsystem 116 that may further include a rotary steering system (RSS) 118 and stabilizer 120 (or some other form of steering assembly) along with drill collars and logging instruments. A fluid circulation subsystem employs a pump 122 to circulate drilling fluid through a feed pipe to the top drive 110, downhole through the interior of drill string 8, through orifices in the drill bit 114, back to the surface via the annulus around the drill string 108, and into a retention pit 124. The drilling fluid transports cuttings from the borehole 112 into the retention pit 124 and aids in maintaining the integrity of the borehole. An
upper portion of the borehole 112 is stabilized with a casing string 113 and the lower portion being drilled is open (uncased) borehole.

The drill collars in the BHA subsystem 116 are typically thick-walled steel pipe sections that provide weight and rigidity for the drilling process. The thick walls are also convenient sites for installing logging instruments that measure downhole conditions, various drilling parameters, and characteristics of the formations penetrated by the borehole. Among the drilling parameters typically monitored downhole are measurements of weight on bit (WOB), downhole pressure, and vibration or acceleration. Further downhole measurements may include torque and bending moments at the bit and at other selected locations along the BHA.

The BHA subsystem 116 typically further includes a navigation tool having instruments for measuring tool orientation (e.g., multi-component magnetometers and accelerometers) and a control sub with a telemetry transmitter and receiver. The control sub coordinates the operation of the various logging instruments, steering mechanisms, and drilling motors, in accordance with commands received from the surface, and provides a stream of telemetry data to the surface as needed to communicate relevant measurements and status information. A corresponding telemetry receiver and transmitter module is located on or near the drilling platform 102 to complete the telemetry link. The most popular telemetry technique modulates the flow of drilling fluid to create pressure pulses that propagate along the drill string ("mud-pulse telemetry or MPT"), but other known telemetry techniques are suitable. Much of the data obtained by the control sub may be stored in memory for later retrieval, e.g., when the BHA 116 physically returns to the surface.

A surface interface 126 serves as a hub for communicating via the telemetry link and for communicating with the various sensors and control mechanisms on the platform 102 of the drilling rig subsystem. A data processing system (shown in Fig. 1 as a tablet computer 128) communicates with the surface interface 126 via a wired or wireless link 130, collecting and processing measurement data to generate logs and other visual representations of the acquired data and the derived models to facilitate analysis by a user. In at least some embodiments, the user may further employ the data processing system to send commands downhole to control the steering mechanism and/or to adjust the surface operating parameters. Representative surface operating parameters include: hook load, torque, rotations per minute (RPM), and rate of penetration (ROP).

The data processing system may take many suitable forms, including one or more of: an embedded processor, a desktop computer, a laptop computer, a central processing facility, and a
virtual computer in the cloud. In each case, software on a non-transitory information storage medium may configure the processing system to carry out the desired processing, modeling, and display generation.

To assist the driller with steering the borehole along a desired trajectory, the BHA 116 may acquire various types of measurement data including multi-component measurements of the earth's magnetic field and gravitational field at each of a series of survey points (or "stations") along the length of the borehole. The survey points are typically those positions where the navigation tool is at rest, e.g., where drilling has been halted to add lengths of drill pipe to the drill string. The gravitational and magnetic field measurements reveal the slope ("inclination") and compass direction ("azimuth") of the borehole at each survey point. When combined with the length of the borehole between survey points (as measureable from the length added to the drill string), these measurements enable the location of each survey point to be determined using known techniques such as, e.g., the tangential method, the balanced tangential method, the equal angle method, the cylindrical radius of curvature method, or the minimum radius of curvature method, to model intermediate trajectories between survey points. When combined together, these intermediate trajectories form an overall borehole trajectory that may be, for example, compared with a desired trajectory or used to estimate relative positions of any desired targets and known obstacles.

Also among the various types of measurement data that may be acquired by the BHA 116 are caliper measurements, i.e., measurements of the borehole's diameter, optionally including the borehole's cross-sectional shape and orientation, as a function of position along the borehole. Such measurements may be combined with the trajectory information to model fluid flows, hole cleaning, frictional forces on the drill string, and stuck pipe probabilities.

Fig. 2 is a function-block diagram of an illustrative directional drilling system. One or more downhole tool controllers 202 collect measurements from a set of downhole sensors 204, preferably but not necessarily including navigational sensors, drilling parameter sensors, and formation parameter sensors, to be digitized and stored, with optional downhole processing to compress the data, improve the signal to noise ratio, and/or to derive parameters of interest from the measurements.

A telemetry system 208 conveys at least some of the measurements or derived parameters to a processing system 210 at the surface, the uphole system 210 collecting, recording, and processing measurements from sensors 212 on and around the rig in addition to the telemetry information from downhole. Processing system 210 generates a display on
interactive user interface 214 of the relevant information, e.g., measurement logs, borehole trajectory, and recommended drilling parameters to optimize a trajectory subject to target tolerances, limits on tortuosity, and information uncertainty. The processing system 210 may further accept user inputs and commands and operate in response to such inputs to, e.g., control the operating parameters of the surface rig and transmit commands via telemetry system 208 to the tool controllers 202. Such commands may alter the settings of the steering mechanism 206.

The software that executes on processing systems 128 and/or 210, addresses the information uncertainty that is typically encountered in the drilling process. Prior to the borehole's completion there are many unknowns, including the environmental uncertainties (e.g., formation properties and boundary locations) and operational uncertainties (e.g., optimal values of operating parameters). If taking an approach that neglects the issue of uncertainty (e.g., the model is presumed accurate, and a fixed schedule is presumed for all events), drillers may use unsuitable operating parameters and/or follow trajectories having undue risk for high tortuosity, stuck pipe, poor formation contact, and rework.

As discussed in greater detail below, the software estimates the level of uncertainty in a drilling system and identifies the source(s). Moreover, the software determines the net value of reducing uncertainty from those sources, and automatically manages the process of uncertainty mitigation. Uncertainty exists in all control systems, whether in the form of sensor noise, model inaccuracies, changes to the physical system, communication delays, or other forms. Control systems are preferably designed to be robust and handle at least some level of uncertainty, though the greater the amount of uncertainty, the more negatively such accommodation affects performance. As field personnel are not expected to have control system design experience, the software is preferably configured to automatically manage the uncertainty by: estimating how much uncertainty exists, determining the sources and the sizes of their contributions, examining the net value of reducing those contributions, and then suitably mitigating those contributions.

Fig. 3A illustrates a first type of uncertainty in the form of a behavior map as a function of RPM and WOB. Marked on the axes are the maximum design WOB 302 and the maximum design RPM 304, defining a WOB parameter range 306 and RPM parameter range 308. Within this range, the processing system has modeled the drilling operation to determine the likelihood of undesirable stick-slip behavior. Due to uncertainties in properties of the formation rock and in how well the drill string model matches the actual drill string, the regions are associated with
probabilities derived from a probability distribution \( p_0 \). Region 310 represents the "good" region, where probability of stick-slip behavior is very low, e.g., less than 10%. Regions 312, 314, and 316 represent regions of increasing probability, with region 316 being the highest probability, e.g., higher than 90%. These regions are expected to vary for different formation properties, different inclinations, different degrees of bit wear, and with different degrees of model mismatch as additional information is obtained and the model is refined.

Fig. 3B illustrates a second type of uncertainty known as "bit walk". Fig. 3B shows a straight "ideal" borehole 320 that the driller seeks to extend along a straight trajectory from end point 322. Even under such idealized circumstances, the actual trajectory 324 may wander off track due to imbalances in the bit-rock interaction forces. The rate at which this occurs exhibits a degree of uncertainty that is often represented by a Gaussian probability distribution \( p_i \), which can be defined in terms of a mean and variance, which may vary with the operating parameters. The mean and variance can be derived by statistical methods, e.g. hypothesis test.

Fig. 3C illustrates a third type of uncertainty. A borehole 330 has been drilled to a point 331 within a formation bed 332 adjacent to a reservoir 334. The driller seeks to extend the borehole along a trajectory below and parallel to the reservoir boundary. However, because the borehole 330 has not yet reached the boundary, the precise boundary position remains uncertain. If the borehole turns too soon (because the driller believes the boundary is at position 336, while it is actually at position 338), the borehole may miss the reservoir until corrective action can be taken. The boundary position uncertainty may be represented by a Gaussian probability distribution \( p_2 \) with a variance that may vary based on how close point 331 is to the boundary.

Fig. 3D illustrates other types of uncertainty. Operating parameter uncertainties 340, represented as having a probability distribution \( p_3 \), arise from causes such as measurement noise. Inaccuracies in the navigational sensors cause uncertainty in the precise location and shape of the borehole trajectory 342, represented here as having a probability distribution \( p_4 \). The degree and distribution of heterogeneity in the formation may also be treated as probabilistic distribution \( p_5 \).

Automated drilling systems may optimize different performance parameters, e.g., ROP, circulation efficiency, downhole pressure, and drilling direction. In some embodiments, an automated drilling system is an integrated combination of multiple control subsystems for different aspects of the drilling system. For example, it may include a surface drilling control subsystem, fluid circulation control subsystem, and BHA control subsystem. The surface
drilling control subsystem may control the surface inputs (e.g., torque and hook load). The fluid circulation control subsystem may control the fluid properties (e.g., density, viscosity, and flow rate). The BHA control subsystem may control geometry (e.g., tool face orientation and bend angle) and bit-rock interaction (e.g., fluid force and flow distribution).

Although these control sub-systems are often treated separately, they are closely coupled. For example, ROP is affected by the surface inputs, the fluid properties, and the bit-rock interactions. The fluid circulation efficiency is affected by the ROP, the fluid properties, and drilling direction (e.g., the inclination angle). Downhole pressure is affected by the ROP, RPM, and the fluid properties. The drilling direction is affected by the ROP, the BHA geometry and the bit-rock interaction.

This close coupling makes it difficult for the control subsystems to maintain their effectiveness in the presence the various forms of uncertainty. For example, in a formation where the bit behavior exhibits a high variance, the subsystem coupling may introduce random dynamics with a broad frequency spectrum that overlaps with that of the reference signals used for feedback control. Such overlap reduces the control subsystem's tracking capability and degrades its effectiveness. Although robust control techniques (e.g. an H\textsubscript{\infty} controller) can be adopted to solve the control problem under uncertainties, the coupled uncertainties may require an overly conservative solution that compromises the drilling efficiency.

Accordingly, the software that executes on processing systems 128 and/or 210 implements an adaptive method for analyzing system sensitivity to uncertainty and providing suitable uncertainty mitigation. The software determines the sensitivity of an overall performance index (e.g., some combination of ROP, circulation efficiency, bottomhole pressure, and drilling path error) with respect to each subsystem. The software then uses the sensitivity analysis results to determine the severity of each uncertainty contribution. Suitably severe contributions are identified and reduced to improve the overall system performance in an efficient manner.

Fig. 4 is a flowchart of an illustrative method that may be implemented by the software. The method begins in block 402, with the processing system retrieving the available historical and real time drilling data, including logs of the system's input parameters (e.g., hook load, topdrive torque, pump rate, pump pressure, choke opening, BHA tool face orientation, etc.), the reference signal measurements (e.g., ROP, RPM, bit behavior, etc.), and measured formation properties. The processing system may also retrieve expected data (e.g., formation models and drilling system models to provide estimated responses to programmable inputs).
General empirical data on the drilling system design and behavior may also be gathered and employed to customize the drilling system model and aid in analyzing sources of uncertainty.

In block 404 the software-configured processing system identifies a comprehensive model for the drilling system. The model may be based on empirical data, real-time drilling data, or derived from first principles. The processing system then decomposes the comprehensive model into a group of interacting subsystem models. Alternatively the subsystem models are identified directly from the data and provided to the software. Each of the subsystem models expresses one of the performance parameters in terms of some subset of the inputs and an internal state.

The comprehensive drilling model can be expressed as:

\[ X = F(X, U) \]
\[ Y = G(X) \quad (1) \]

where \( X' \) is a vector of subsequent internal states, which is a function of the current state vector \( X \) and the system inputs \( U \). \( Y \) is a vector of the system outputs, which are a function of the current state vector \( X \). \( Y \) may include ROP, circulation efficiency, downhole pressure, and drilling direction. While the functions are generally nonlinear, the drilling process changes slowly in the short term, enabling the model to be linearized for control purposes:

\[ X' = AX + BU \]
\[ Y = CX \quad (2) \]

where \( A, B, \) and \( C \) are matrices. The linearized equation can be broken down in terms of subsystem interaction states:

\[ x'_y = a_y x_y + b_y u_j \]
\[ y_i = \sum_j y_j = c_y x_y \quad (3) \]

where \( x_y \) is the interaction state reflecting the impact of input \( u \) on subsystem \( i \), which yields subsystem output \( y \), as the combination of contributions from the interaction states for that subsystem. For example, the interaction dynamics between the mud circulation system and the surface drilling system are captured by the interaction states (representing, e.g., position and speed) that reflect the impact of inputs for the mud circulation system (e.g., the pump pressure, flow rate and choke opening).

When uncertainties are considered, the linearized subsystem equations become

\[ x'_y = (a_y + \Delta_y) x_y + b_y u_j + v_y \]
\[ y_i = \sum_j y_j + w_i = \sum_j c_y x_j + w_i \quad (4) \]
where $\Delta_i$ is the interaction model uncertainty due to, e.g. the model inaccuracy and incomplete information, $v_y$ denotes the uncertainties that impact the interaction states, for example the uncertainties associated with the rock surface profile or a formation anomaly, and $w_i$ denotes the measurement uncertainties which are from the sensing noise or estimation error (when the outputs cannot be directly measured).

In blocks 406 and 408, the processing system characterizes the uncertainties associated with the model, the interaction states, and the output measurements. The characterization yields a probability distribution function for each of the uncertainties, which may be derived from historical data, set based on empirical evidence, or obtained by system characterization.

In block 410, the software causes the processing system to analyze the system sensitivity to uncertainty, i.e., to quantify the impact of the uncertainties associated with each sub-system to the overall system's performance. Various suitable methods exist for this analysis. In at least some embodiments, the software implements a Monte Carlo simulation to analyze the system's sensitivity to disturbance and uncertainties in the absence of explicit inputs (i.e., $\xi$ is taken as being equal to zero). Using the probability distributions derived in blocks 406 and 408, the software randomly samples $A_y$, $v_y$, $w_i$, and initial states $x_{i,y}$. For each set of samples, the software determines a subsequent state $x_{i,y}'$ (again, assuming a zero input), and the corresponding interaction state outputs $y_{i,y}$ calculated from that subsequent state. The probability distributions for interaction state outputs $y_{i,y}$ and subsystem outputs $y_i$ are then characterized, e.g., using histograms.

Based on equation (4), the output distribution of $y$, will be a convolution of the distributions for $y_{i,y}$ and $w_i$. Because the subsystem outputs must be maintained within an operational envelope, excessive degrees of uncertainty may limit operating parameters to a suboptimal range of values. The performance loss of the system as compared with that achievable with optimized operating parameter values may be used to evaluate the benefits of uncertainty mitigation. Those subsystems having interaction state output distributions with high variances are the primary contributors to the variance in the subsystem output distribution and may be prioritized for mitigation. The Monte Carlo-based sensitivity analysis can also be applied to the (nonlinear) comprehensive drilling model incorporating uncertainty:

$$X' = [F + A](X, U, V)$$
$$Y = G(X, W)$$

(5)

Alternatively, or in addition, the software may incorporate the feedback control function into the sensitivity analysis. From equation (4) the open-loop transfer function in the
Laplace domain is:

\[ G_s = \frac{b_y c_y}{s-a_y} \]

Augmenting equation (4) with the feedback equation

\[ u_j = k_{ij} - r_i \] (7)

(where \( r_i \) is the desired value for output \( y_i \), and \( k_{ij} \) is the feedback error gain for input \( u_j \)) yields a closed loop transfer function of

\[ H_s = \frac{k_{ij} \cdot (G_s + \Delta_s)}{1 + k_{ij} \cdot (G_s + \Delta_s)} \].

This closed loop transfer function remains stable so long as there is no complex right-hand plane (RHP) value of the Laplace variable \( s \) for which the denominator is zero. This criterion can be restated in terms of ensuring that the contour around the right half of the complex plane (which represents all values of \( s \) having a non-negative real part), when mapped through the function \( k_{ij} \cdot (G_s + \Delta_s) \), does not enclose \(-1+0/\) This mapped contour, known as the Nyquist plot, is a function of \( k_{ij} \) and \( G_s \) for a given value of model uncertainty \( \Delta_s \). Assuming the contour does not enclose \(-1+0/\), the margin of stability is the shortest distance between this contour and \(-1+0/\), or

\[ m = \min_{\omega} \| G_s + A \| \] (9)

When there is no model uncertainty, the Nyquist plot correspond to interaction state \( x_{ij} \) can be accurately determined and the margin of stability readily calculated. When the model uncertainty \( \Delta_{x_s} \) is present, its range blurs the contour of the original Nyquist plot into band of possible contours. For a given error gain \( k_{ij} \), the range of the uncertainty \( \Delta_{x_s} \) determines the system's margin of stability. If the range of uncertainty is large enough to eliminate the stability margin, the error gain \( k_{ij} \) must be reduced if stability is to be guaranteed, yet such reductions translate into a performance loss. Alternatively, mitigation may be performed to reduce the range of uncertainty and perhaps enable an increase in the error gain.

In block 412 the software configures the processing system to determine the net benefit of reducing the various uncertainties. As part of this block, the processing system accounts for the effort required to reduce the various uncertainties. Such uncertainty reduction may take various forms, each of which may have a (temporary) adverse impact on the drilling performance, as measured by ROP, circulation efficiency, downhole pressure, drilling direction, bit wear or other performance parameters. For example, to reduce the interaction
model uncertainties \( \Delta y \), a system identification process may be executed to re-characterize the drilling model, e.g., by applying systematic perturbations to the various inputs and observing the responses of the subsystems and changes to the overall system behavior. The perturbations may need to cover a significant portion of the operating ranges for the inputs at a range of frequencies to adequately reduce the interaction model uncertainties, significantly reducing the time spent near the optimum operating point during the process.

As another example, the input uncertainties \( v_{ij} \) that may be associated with the rock surface profile or formation anomalies may be mitigated by collecting and analyzing logging while drilling (LWD) data for the formation. Often such data collection involves a pause in drilling and/or a regulation of fluid flow to enable effective mud-pulse telemetry (MPT). As still another example, the measurement uncertainties \( w_i \) may be mitigated with the installation of additional or improved sensors, which typically requires a temporary cessation of drilling operations.

The processing system further estimates the improvement in drilling performance that the contemplated uncertainty mitigation would be expected to produce, e.g., by enabling the use of a more aggressive feedback error gain, or by enabling the use of more optimal operating parameter values. An adjustable time frame may be employed for evaluating this improvement, on the grounds that the improvement is temporary due to the expected gradual increase of uncertainties during operations. For example, uncertainties such as frictional effects with the wellbore will change as the mud properties change and as the wellbore profile changes. Therefore the benefit phase for improvement in such uncertainties may be limited to the next several hundred feet of drilling, instead of the remaining well path. The net benefit may be expressed as:

\[
N = \int_{t-T_i}^{t-T_2} \text{improvement} \, dt - \int_{t-T_i}^{t-T_2} \text{loss} \, dt + \text{benefit} - \text{cost}
\]  

(10)

where \( t \) is the current time, \( T_i \) is the time required for mitigation ("mitigation phase"), \( T_2 \) is the adjustable time frame for evaluating the improvement ("benefit phase"), \( \text{improvement} \) is the square root of a weighted sum of squares of changes to the performance parameters (e.g., ROP, bit wear rate, path error, risk of non-productive time) after the uncertainty mitigation relative to pre-mitigation performance, \( \text{loss} \) is the square root of the same weighted sum for changes to the performance parameters during the uncertainty mitigation, \( \text{benefit} \) is the sum of non-time based benefits achieved by the mitigation (e.g., diagnostics value), and \( \text{cost} \) is the sum of non-time based costs required for the mitigation (e.g., new sensors, non-productive time to be incurred). The improvement and loss may be calculated using a subset of the performance
parameters, or higher weights may be assigned to those parameters considered more critical.

The net benefit function may be evaluated using a model (which could be either deterministic or probabilistic model) of the uncertainty mitigation technique on the operational inputs and the estimated uncertainty reduction with the drilling process over the benefit phase. For example, to reduce the uncertainty in the rock/bit model by using system identification over a specified operational space (perhaps by mapping of the torque input to ROP with a specified discretization for steady state input), the amount of time to achieve this can be determined. Where multiple mitigation techniques may be applied jointly, the software calculates the net benefit for each combination and identifies the combination yielding the maximum net benefit.

In block 414, the software-configured processing system determines whether the net benefit exceeds a threshold (e.g., zero), and if not, the processing system employs the existing model in block 416 for continued drilling. For example, dynamics of bit-rock interactions may be the largest sources of model uncertainties, yet mitigation might often require ROP reductions that are too substantial for the mitigation to be justified. Accordingly, the existing uncertainty ranges are used to set the control gains $k_j$ as needed to provide the desired margin for stability. Where the system is subject to high uncertainties, the control gain would be low, and where the uncertainties are low, the control gain can be more aggressive without losing the stability.

Otherwise, where mitigation is justified, the processing system in block 418 recommends or initiates mitigation of the uncertainties that provide the maximum net benefit. The software may include experiment design techniques for system identification, enabling the processing system to automate the uncertainty mitigation. The system (or subsystem) model is re-calibrated, multiple sensor measurements (including repeated measurements or redundant sensors) are fused, and/or equipment is replaced/upgraded, thereby reducing the selected uncertainties. In block 420, the drilling proceeds with reduced uncertainties, providing a greater margin of stability or enabling the use of more aggressive control gains to maintain the same margin of stability while enhancing drilling system performance.

As drilling proceeds with block 416 or 420, the software-configured processing system collects additional data in block 424 to augment the data from block 402. The processing system repeats blocks 404-424 with the gradually increasing data set to provide automated uncertainty mitigation for the drilling process. This systematic approach to automated uncertainty analysis and mitigation is suitable for field use with operators to optimize
performance with little or no experience in drilling control systems.

Accordingly, the embodiments disclosed herein include:

Embodiment A: A drilling method that comprises: obtaining a model of a drilling
system having subsystem inputs that control one or more performance parameters of the
drilling system, said model having interaction states that each represent one of said subsystem
input's impact on a subsystem of the drilling system; estimating a probability distribution of a
model uncertainty for each interaction state; evaluating an influence of each interaction state's
model uncertainty on each of said performance parameters; calculating a net benefit for
mitigating one or more of said model uncertainties; automatically mitigating said one or more
model uncertainties when the net benefit exceeds a threshold, thereby improving the model of
the drilling system; and controlling the drilling system based on the model.

Embodiment B: A drilling system that comprises: a drilling assembly having subsystem
inputs that control one or more performance parameters of the drilling system; and a processing
system that provide automated uncertainty mitigation of a model for controlling the drilling
assembly. The drilling assembly includes: a bottomhole assembly (BHA) subsystem with a
steerable drill bit; and a drill string that connects the BHA subsystem to a drilling rig subsystem
and a fluid circulation subsystem. The processing system provides uncertainty mitigation by:
obtaining a model of the drilling system, said model having interaction states that each
represent an impact of one of said subsystem inputs on one of: the BHA subsystem, the drilling
rig subsystem, and the fluid circulation subsystem; estimating a probability distribution of a
model uncertainty for each interaction state; evaluating an influence of each interaction state's
model uncertainty on each of said performance parameters; calculating a net benefit for
mitigating one or more of said model uncertainties; automatically mitigating said one or more
model uncertainties when the net benefit exceeds a threshold, thereby improving the model of
the drilling system; and controlling the subsystem inputs based on the model.

Each of the foregoing embodiments may further include any of the following additional
elements alone or in any suitable combination: 1. The model further accounts for subsystem
input uncertainties and performance parameter measurement uncertainties. 2. The model is
expressible as

\[ x'_y = (a_y + \Delta_y)x_y + b_y u_j + v_y \]

\[ y_i = \sum_j y_j + w_i = \sum_j c_y x_y + w_i \]

where\( j \) is the subsystem input index, \( u_j \) is the subsystem input, \( i \) is the performance parameter
index, \( y \) is the performance parameter, \( x_y \) is the interaction state, \( v_y \) is the subsystem input
uncertainty, $\Delta_{s \sigma}$ is the interaction model uncertainty, $w_i$ is the performance parameter measurement uncertainty, and model coefficients are $a_y$, $b_y$, and $c_y$. 3. Said performance parameters comprise one or more of: rate of penetration (ROP); circulation efficiency, bottomhole pressure, drilling path error, and bit wear. 4. The subsystem inputs include one or more of: hook load, topdrive torque, rotation rate (RPM), pump rate, pump pressure, choke opening, tool face orientation, and fluid viscosity. 5. Said net benefit accounts for performance parameter degradation during a mitigation process and duration of the mitigation process. 6. Said net benefit further accounts for achievable performance parameter improvements. 7. The achievable performance parameter improvements are determined based on maintaining a margin of stability. 8. The threshold is zero.

Numerous other modifications, equivalents, and alternatives, will become apparent to those skilled in the art once the above disclosure is fully appreciated. It is intended that the following claims be interpreted to embrace all such modifications, equivalents, and alternatives where applicable.
WHAT I CLAIMED IS:

1. A drilling method that comprises:
   - obtaining a model of a drilling system having subsystem inputs that control one or more performance parameters of the drilling system, said model having interaction states that each represent one of said subsystem input's impact on a subsystem of the drilling system;
   - estimating a probability distribution of a model uncertainty for each interaction state;
   - evaluating an influence of each interaction state's model uncertainty on each of said performance parameters;
   - calculating a net benefit for mitigating one or more of said model uncertainties;
   - automatically mitigating said one or more model uncertainties when the net benefit exceeds a threshold, thereby improving the model of the drilling system; and
   - controlling the drilling system based on the model.

2. The method of claim 1, wherein the model further accounts for subsystem input uncertainties and performance parameter measurement uncertainties.

3. The method of claim 2, wherein the model is expressible as
   \[ x_j' = (a_j + \Delta_j)x_j + b_j u_j + v_j \]
   \[ y_i = \sum_j x_j' + w_i = \sum_j c_{ij} x_j' + w_i \]
   where \( j \) is the subsystem input index, \( x_j \) is the subsystem input, \( i \) is the performance parameter index, \( y_i \) is the performance parameter, \( x_j' \) is the interaction state, \( v_j \) is the subsystem input uncertainty, \( A_y \) is the interaction model uncertainty, \( w_i \) is the performance parameter measurement uncertainty, and model coefficients are \( a_j, b_j, \) and \( c_{ij} \).

4. The method according to any of claims 1-3, wherein said performance parameters comprise one or more of: rate of penetration (ROP); circulation efficiency, bottomhole pressure, drilling path error, and bit wear.

5. The method according to any of claims 1-3, wherein the subsystem inputs include one or more of: hook load, topdrive torque, rotation rate (RPM), pump rate, pump pressure, choke opening, tool face orientation, and fluid viscosity.

6. The method according to any of claims 1-3, wherein said net benefit accounts for performance parameter degradation during a mitigation process and duration of the mitigation process.

7. The method of claim 6, wherein said net benefit further accounts for achievable performance parameter improvements.
8. The method of claim 7, wherein the achievable performance parameter improvements are determined based on maintaining a margin of stability.

9. The method according to any of claims 1-3, wherein the threshold is zero.

10. A drilling system that comprises:
    a drilling assembly having subsystem inputs that control one or more performance parameters of the drilling system, the drilling assembly including:
        a bottomhole assembly (BHA) subsystem with a steerable drill bit; and
        a drill string that connects the BHA subsystem to a drilling rig subsystem and a fluid circulation subsystem; and
    a processing system that provides automated uncertainty mitigation of a model for controlling the drilling assembly by:
        obtaining a model of the drilling system, said model having interaction states that each represent an impact of one of said subsystem inputs on one of: the BHA subsystem, the drilling rig subsystem, and the fluid circulation subsystem;
        estimating a probability distribution of a model uncertainty for each interaction state;
        evaluating an influence of each interaction state's model uncertainty on each of said performance parameters;
        calculating a net benefit for mitigating one or more of said model uncertainties;
        automatically mitigating said one or more model uncertainties when the net benefit exceeds a threshold, thereby improving the model of the drilling system; and
        controlling the subsystem inputs based on the model.

11. The system of claim 10, wherein the model further accounts for subsystem input uncertainties and performance parameter measurement uncertainties.

12. The system of claim 11, wherein the model is expressible as

    \[ x'_j = (a_j + \Delta_y) x_j + b_j u_j + v_j \]
    \[ y_i = \sum_j^x y_j + w_i = \sum_j^c y_j x_j + w_i \]

where \( j \) is the subsystem input index, \( u_j \) is the subsystem input, \( i \) is the performance parameter index, \( y_i \) is the performance parameter, \( x_j \) is the interaction state, \( v_j \) is the subsystem input uncertainty, \( \Delta_y \) is the interaction model uncertainty, \( w_i \) is the performance parameter measurement uncertainty, and model coefficients are \( a_j, b_j, \) and \( c_j \).

13. The system according to any of claims 10-12, wherein said performance parameters comprise one or more of: rate of penetration (ROP); circulation efficiency, bottomhole...
pressure, drilling path error, and bit wear.

14. The system according to any of claims 10-12, wherein the subsystem inputs include one or more of: hook load, topdrive torque, rotation rate (RPM), pump rate, pump pressure, choke opening, tool face orientation, and fluid viscosity.

15. The system according to any of claims 10-12, wherein said net benefit accounts for performance parameter degradation during a mitigation process and duration of the mitigation process.

16. The system of claim 15, wherein said net benefit further accounts for achievable performance parameter improvements.

17. The system of claim 16, wherein the achievable performance parameter improvements are determined based on maintaining a margin of stability.

18. The system according to any of claims 10-12, wherein the threshold is zero.
Fig. 4

START

1. Obtain available drilling data and expected data

2. Identify drilling model, subsystems & interactions

3. Characterize state and interaction uncertainties

4. Characterize measurement uncertainties

5. Analyze system sensitivity to each uncertainty

6. Determine cost & benefit for mitigating each uncertainty

7. Sufficient benefit detected? (Y/N)
   - Y: Drill with existing model
   - N: Mitigate selected uncertainties

8. Collect more data

9. Drill with improved model
### A. CLASSIFICATION OF SUBJECT MATTER

E21B 7/06(2006.01)i, E21B 41/00(2006.01)i, E21B 44/00(2006.01)i

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

### B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
E21B 7/06; G05B 13/04; G06F 17/10; E21B 44/00; E21B 47/022; E21B 47/12; E21B 7/04; E21B 41/00

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

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
eKOMPASS(KIPO internal) & Keywords: directional drilling, model uncertainty, mitigation, evaluation, subsystem input, interaction state, net profit, performance parameter

### C. DOCUMENTS CONSIDERED TO BE RELEVANT

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<th>Relevant to claim No.</th>
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<td>US 2016-0290118 (HALLIBURTON ENERGY SERVICES, INC.) 06 Oct 2016 See paragraphs [0044] - [0049], claim 1, and figure 1.</td>
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Further documents are listed in the continuation of Box C. See patent family annex.

- **A** Special categories of cited documents:
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  - "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
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- **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: 28 April 2017 (28.04.2017)

Date of mailing of the international search report: 01 May 2017 (01.05.2017)

Name and mailing address of the ISA/KR
International Application Division
Korean Intellectual Property Office
189 Cheongsa-ro, Seo-gu, Daejeon, 35208, Republic of Korea

Facsimile No. +82-42-481-8578

Authorized officer: LEE, Jong Kyung
Telephone No. +82-42-481-3360

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