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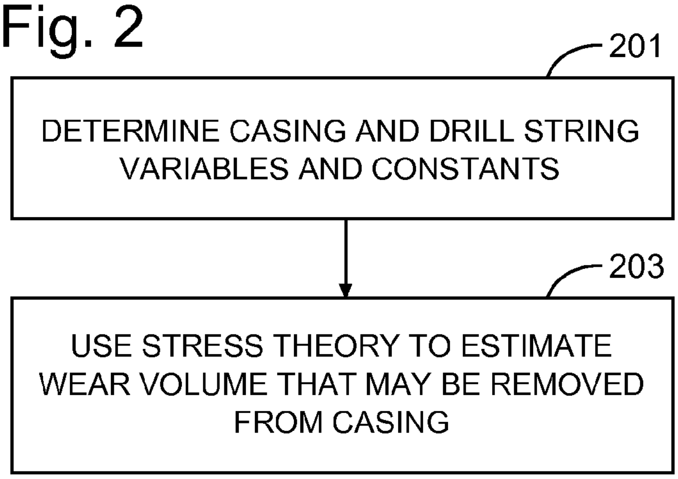
(54) Title: METHOD AND APPARATUS FOR CASING THICKNESS ESTIMATION

Fig. 2



(57) Abstract: Various embodiments include apparatus and methods to provide an estimation of casing wear. One method determines values of casing and drill string variables and constants. These constants and variables are used to dynamically generate an estimate of casing wear, based on a stress theory. The drilling operation can be halted when the estimate of casing wear reaches a predetermined value.

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METHOD AND APPARATUS FOR CASING THICKNESS ESTIMATION

BACKGROUND

[0001] Casing wear resulting from borehole drilling and back-reaming can have an impact on the integrity of the borehole casing, liner, and riser. The casing wear can be attributed to large bit footage, high rotating hours, and increased contact force between the drill string and the casing. A crescent-shaped groove, resulting from the casing wear, that exceeds allowable limits in the casing wall can jeopardize the casing integrity and cause the abandonment of a hole before reaching target depth. Tool joint wear can also result from the contact between the drill string and the casing.

BRIEF DESCRIPTION OF THE DRAWINGS

[0002] FIG. 1 shows an embodiment of a deformable casing pressed against a tool joint.

[0003] FIG. 2 illustrates a flowchart of an embodiment of a method for pre-planning of a drilling operation.

[0004] FIG. 3 illustrates a flowchart of an embodiment of a method for a real-time analysis of the drilling operation.

[0005] FIG. 4 illustrates a flowchart of an embodiment of a method for post-planning of the drilling operation.

[0006] FIG. 5 shows a block diagram of an embodiment of a system operable to perform casing thickness reduction estimation.

[0007] FIG. 6 wireline system implementation.

[0008] FIG. 7 drilling system implementation.

DETAILED DESCRIPTION

[0009] The following detailed description refers to the accompanying drawings that show, by way of illustration and not limitation, various embodiments in which the invention may be practiced. These embodiments are described in sufficient detail to enable those skilled in the art to practice these and other embodiments. Other embodiments may be utilized, and structural, logical, and electrical changes may be made to these embodiments. The various embodiments are not necessarily mutually exclusive, as some embodiments can be combined with one or more other embodiments to form new embodiments. The following detailed description is, therefore, not to be taken in a limiting sense.

[0010] Casing wear, sometimes appearing in the form of a crescent-shaped groove, can result from a large bit footage, high rotating hours, and/or increased contact force between the drill string tool joint and the casing. Hertzian contact mechanics can be used to identify the loading conditions that may cause deformation to begin in the casing.

[0011] FIG. 1 illustrates a rigid drill string tool joint 101 pressed against a deformable casing 103. During a drilling operation, the casing 103 can exhibit wear 105 from the drill string tool joint 101.

[0012] The rate of casing volume wear can be represented by:

$$\frac{dV}{dt} = 2\pi r_{tj} L \frac{dr}{dt} \qquad \text{(Eq. 1)}$$

where:

r_{tj} = radius of the tool joint,

L = drilling distance (ft) of the tool joint, and

dr/dt = rate of change in the radius due to wear with respect to time.

[0013] If δ represents the thickness of the casing that is worn from wear and differentiating with respect to time, t:

$$\frac{d\delta}{dt} = \frac{dr}{dt} \qquad \text{(Eq. 2)}$$

[0014] After substituting Eq. 2 into Eq. 1, Eq. 1 becomes:

$$\frac{dV}{dt} = 2\pi r_{tj} L \frac{d\delta}{dt} \qquad \text{(Eq. 3)}$$

[0015] Eq. 3 can be rearranged as:

$$\frac{dV}{dt} = 2\pi r_{tj} L \frac{d\delta}{d\theta} \frac{d\theta}{dt} \qquad \text{(Eq. 4)}$$

[0016] Given:

$$\frac{d\theta}{dt} = \varpi = 2\pi N \qquad \text{(Eq. 5)}$$

[0017] Substituting Eq. 5 into Eq. 4 yields:

$$\frac{dV}{dt} = \pi D_{tj} NL \frac{d\delta}{d\theta} \qquad \text{(Eq. 6)}$$

[0018] Assuming the rate of wear is uniform throughout the casing at different azimuthal angles, it can be assumed that the rate of wear at different angular positions is directly proportional to the maximum stress at the point of contact between the tool and the casing. So:

$$\frac{d\delta}{d\theta} = k\sigma_{max} \qquad \text{(Eq. 7)}$$

where k = a proportionality constant that depends on the casing material and a wear coefficient.

[0019] Substituting Eq. 7 into Eq. 6 produces:

$$\frac{dV}{dt} = \pi D_{tj} NLkL\sigma_{max} \qquad \text{(Eq. 8)}$$

[0020] A tool joint can have a hard coating to prevent the associated drill pipe from touching the wellbore wall and causing excessive wear to the tool joint. However, the hard coating can cause wear in the casing that is typically referred to as “tool joint hard banding”. Contact stresses can be functions of tool joint geometry, material properties of tool joint hard banding, and/or the contact forces acting between the tool joint and the casing. A large number of cyclic contact stresses can cause excessive casing wear and tool joint wear. As a result, physical deterioration can occur on both of the engaged surfaces but may be more conspicuous in the weaker material (e.g., casing).

[0021] Because of the sliding velocity between the tool and the casing, elastohydrodynamic effects may be present in the casing element that can alter the stress distribution. Dynamic loading is another factor that can alter the stress at contact points between the tool and casing. Such dynamic loading can occur when the drill string vibrates and touches the casing with an impact loading instead of static loading.

[0022] Using a classical Hertzian approach, the maximum compressive stress at the point of contact between the casing and the tool joint can be expressed as:

$$\sigma_{\max} = 0.564\left[\frac{F_n \frac{(\rho_c - \rho_{tj})}{\rho_c \rho_{tj}}}{\left(\frac{1-\mu_c^2}{E_c}\right)+\left(\frac{1-\nu_{tj}^2}{E_{tj}}\right)}\right]^{\frac{1}{2}} \qquad \text{(Eq. 9)}$$

where:

F_n = normal load per unit width of the contacting element that is calculated based on the position of the drill string (e.g., inclination, azimuth),

ρ_c, ρ_{tj} = radii of curvature of casing and tool joint, respectively,

E_c , E_{tj} = modulii of elasticity of casing and tool joint, respectively, and

ν_c, ν_{tj} = Poisson's ratio of casing and tool joint, respectively.

[0023] Substituting Eq. 9 into Eq.8 yields:

$$\frac{dV}{dt} = \pi 0.564 D_{tj} NLkL\left[\frac{F_n \frac{(\rho_c - \rho_{tj})}{\rho_c \rho_{tj}}}{\left(\frac{1-\mu_c^2}{E_c}\right)+\left(\frac{1-\nu_{tj}^2}{E_{tj}}\right)}\right]^{\frac{1}{2}} \qquad \text{(Eq. 10)}$$

[0024] To evaluate the force, F_n, acting on the contact point, Eq. 10 can be integrated and the sliding distance replaced with a rotational speed in revolutions per minute (RPM). This results in the volume, V, that is removed per linear distance from the casing as a result of contact between the rotating drill string and the casing:

$$V = \pi 0.564 k F_n D_{tj} N L t \left[\frac{\frac{(\rho_c - \rho_{tj})}{\rho_c \rho_{tj}}}{\left(\frac{1-\mu_c^2}{E_c}\right) + \left(\frac{1-\nu_{tj}^2}{E_{tj}}\right)} \right]^{\frac{1}{2}} \text{ inches}^3/\text{feet} \quad \text{(Eq. 11)}$$

where:

N = rotary speed (revolutions per minute)

D_{tj} = tool-joint diameter (inches)

t = contact time (minutes)

[0025] The contact time, t, between the rotating drill string and the casing can be expressed by:

$$t = \frac{L \times L_{tj}}{ROP \times L_{dp}} \text{ min.} \quad \text{(Eq. 12)}$$

where L = drilling distance (depth in feet) so that:

L_{tj} = drilling distance (depth in feet) of the tool joint,

L_{dp} = drilling distance (depth in feet) of the drill string; and

ROP = rate of penetration into a geological formation in feet/minute

[0026] The volume removed per linear distance, as expressed by the model of Eq. 11, can be used in multiple modes of a drilling operation. These modes can include pre-planning for the drilling operation, real-time analysis of the drilling operation, and post-planning of the drilling operation.

[0027] FIG. 2 illustrates a flowchart of an embodiment of a method for pre-planning of a drilling operation. The casing and drill string variables and constants used to determine the casing wear, as described previously, can be determined 201. For example, these variables and constants may include the normal load per unit width of the contacting element that is calculated based on the position of the string (e.g., inclination, azimuth) (e.g., F_n), the radii of curvature of the casing and the tool joint (e.g., ρ_c, ρ_{tj}), the modulii of elasticity of casing and the tool joint of the drill string (e.g., E_c , E_{tj}), and the Poisson's ratio of the casing and the tool joint of the drill string (e.g., ν_c, ν_{tj}).

[0028] Using the above information, the casing wear estimation model illustrated in Eq. 11 can thus be used to determine 203 when the casing thickness is adequate and safe for drilling. The casing wear estimation model illustrated in Eq. 11 is based on stress theory to estimate the wear volume that may be removed from the casing during the drilling operation.

[0029] FIG. 3 illustrates a flowchart of an embodiment of a method for real-time analysis of the drilling operation to determine casing wear. Data from sensors in the drill string are read to monitor the drilling operation 301. The data can include the distance/depth of drilling, the rotational speed of the drill string, the ROP, and the length of the drill string. This data can be combined with variables and constants obtained during the pre-planning method, outlined previously, in order to dynamically update the casing wear estimation model illustrated in Eq. 11 303. This can provide a constant estimate of casing wear as the drilling operation is executed and, thereby, provide a safety factor during the drilling operation. If the safety factor reaches an undesired level (i.e., the safety factor indicates that the casing might be getting thinner than a thickness threshold for safe operation) the drilling operation can be stopped 305.

[0030] As an example of operation, a processor that is controlling the drilling operation can stop the drill when the safety factor reaches a predetermined level. In another operational embodiment, an indication provided by a controller can be used to inform a drill operator that the drilling operation should be stopped manually when the safety factor reaches the predetermined level.

[0031] FIG. 4 illustrates a flowchart of an embodiment of a method for post-planning of the drilling operation. After the drilling operation, the casing wear can be measured 401. Logs of data from the drilling operation can be accessed to gather statistical data regarding the drilling operation 403. This data can include the distance of drilling, the rotational speed of the drill string, as well as other data. The casing wear estimation model can be updated for future use 405 using the actual measured wear and the log data.

[0032] In various embodiments, a non-transitory machine-readable storage device can comprise instructions stored thereon, which, when performed by a machine, cause the machine to perform operations, the operations comprising one or more features similar to or identical to features of methods and techniques related to performing an estimation of casing wear. These operations include any one or all of the operations forming the methods shown in FIGs. 2-4. The physical structure of such instructions may be operated on by one or more processors.

[0033] A machine-readable storage device, herein, is a physical device that stores data represented by physical structure within the device. Examples of non-transitory machine-readable storage devices can include, but are not limited to, read only memory (ROM), random access memory (RAM), a magnetic disk storage device, an optical storage device, a flash memory, and other electronic, magnetic, and/or optical memory devices.

[0034] In various embodiments, a system can comprise a controller (e.g., processor) and a memory unit arranged such that the processor and the memory unit are configured to perform one or more operations in accordance with techniques to perform the estimation of casing wear that are similar to or identical to methods taught herein. The system can include a communications unit to receive data generated from one or more sensors disposed in a wellbore. The one or more sensors can include a fiber optic sensor, a pressure sensor, a drill string rotational sensor, or a strain gauge to provide monitoring of drilling and production associated with the wellbore. A processing unit may be structured to perform processing techniques similar to or identical to the techniques discussed herein. Such a processing unit may be arranged as an integrated unit or a distributed unit. The processing unit can be disposed at the surface of a wellbore to analyze data from operating one or more measurement tools downhole. The processing unit can be disposed downhole in as part of a sonde (e.g., in a wireline application) or a downhole tool, as part of a drill string (see FIGs. 6-7 below).

[0035] Figure 5 depicts a block diagram of features of an embodiment of an example system 500 operable to perform related to performing the estimation of casing wear. The system 500 can include a controller 525, a memory 535, an electronic apparatus 565, and a communications unit 540. The controller 525 and the memory 535 can be realized to manage processing schemes as described herein.

[0036] The memory 535 can be realized as one or more non-transitory machine-readable storage devices having instructions stored thereon. The instructions, when performed by a machine, can cause the machine to perform operations, the operations comprising the performance of estimating casing wear as taught herein. The controller 525 and the memory 535 can also be arranged to operate the one or more evaluation tools 505 to acquire measurement data as the one or more evaluation tools 505 are operated.

[0037] The processing unit 520 may be structured to perform the operations to manage processing schemes that include estimating casing wear in a manner similar to or identical to embodiments described herein. The system 500 may also include one or more evaluation tools 505 having one or more sensors 510 operable to make casing measurements with respect to a wellbore. The one or more sensors 510 can include, but are not limited to, a fiber optic sensor, a pressure sensor, or a strain gauge to provide monitoring drilling and production associated with the wellbore.

[0038] Electronic apparatus 565 can be used in conjunction with the controller 525 to perform tasks associated with taking measurements downhole with the one or more sensors 510 of the one or more evaluation tools 505. The communications unit 540 can include downhole communications in a drilling operation. Such downhole communications can include a telemetry system.

[0039] The system 500 can also include a bus 527. The bus 527 can provide electrical conductivity among the components of the system 500. The bus 527 can include an address bus, a data bus, and a control bus, each independently configured. The bus 527 can also use common conductive lines for providing one or more of address, data, or control, the use of which can be regulated by the controller 525.

[0040] The bus 527 may include network capabilities. The bus 527 can include optical transmission medium to provide optical signals among the various components of system 500. The bus 527 can be configured such that the components of the system 500 are distributed. Such distribution can be arranged between downhole components such as one or more sensors 510 of the one or more evaluation tools 505 and components that can be disposed on the surface of a well. Alternatively, various of these components can be co-located such as on one or more collars of a drill string, on a wireline structure, or other measurement arrangement (e.g., see FIGs. 6-7).

[0041] In various embodiments, peripheral devices 545 can include displays, additional storage memory, and/or other control devices that may operate in conjunction with the controller 525 and/or the memory 535. In an embodiment, the controller 525 can be realized as one or more processors. The peripheral devices 545 can be arranged to operate in conjunction with display unit(s) 555 with instructions stored in the memory 535 to implement a user interface to manage the operation of the one or more evaluation tools 505 and/or components distributed within the system 500. Such a user interface can be operated in conjunction with the communications unit 540 and the bus 527 and can provide for control and command of operations in response to analysis of the completion string or the drill string. Various components of the system 500 can be integrated to perform processing identical to or similar to the processing schemes discussed with respect to various embodiments herein.

[0042] FIG. 6 illustrates a wireline system 664 embodiment. FIG. 7 illustrates a drilling rig system 764 embodiment. During a drilling operation of the well 712, as illustrated in FIG. 7, it may be desirable to estimate the casing wear.

[0043] The system 664 of FIG. 6 may comprise portions of a tool body 670 as part of a wireline logging operation that can include one or more sensors 600. The system of FIG. 7 may comprise a downhole measurement tool 724, as part of a downhole drilling operation, that can also include one or more sensors 700.

[0044] FIG. 6 shows a drilling platform 686 that is equipped with a derrick 688 that supports a hoist 690. Drilling of oil and gas wells is commonly carried out using a string of drill pipes connected together so as to form a drilling string that is lowered through a rotary table 610 into a wellbore or borehole 612. Here it is assumed that the drilling string has been temporarily removed from the borehole 612 to allow a wireline logging tool body 670, such as a probe or sonde, to be lowered by wireline or logging cable 674 into the borehole 612. Typically, the tool body 670 is lowered to the bottom of the region of interest and subsequently pulled upward at a substantially constant speed.

[0045] During the drilling of the nearby ranging well, measurement data can be communicated to a surface logging facility 692 for storage, processing, and/or analysis. The logging facility 692 may be provided with electronic equipment 654, 696, including processors for various types of signal processing, which may be used by the casing wear estimation model.

[0046] FIG. 7 shows a system 764 that may also include a drilling rig 702 located at the surface 704 of a well 706. The drilling rig 702 may provide support for a drill string 708. The drill string 708 may operate to penetrate a rotary table for drilling a borehole 712 through subsurface formations 714. The drill string 708 may include a Kelly 716, drill pipe 718, and a bottom hole assembly 720, perhaps located at the lower portion of the drill pipe 718.

[0047] The bottom hole assembly 720 may include drill collars 722, a downhole tool 724, and a drill bit 726. The drill bit 726 may operate to create a borehole 712 by penetrating the surface 704 and subsurface formations 714. The downhole tool 724 may comprise any of a number of different types of tools including MWD (measurement while drilling) tools, LWD tools, and others.

[0048] During drilling operations, the drill string 708 (perhaps including the Kelly 716, the drill pipe 718, and the bottom hole assembly 720) may be rotated by the rotary table. In addition to, or alternatively, the bottom hole assembly 720 may also be rotated by a motor (e.g., a mud motor) that is located downhole. The drill collars 722 may be used to add weight to the drill bit 726. The drill collars 722 may also operate to stiffen the bottom hole assembly 720, allowing the bottom hole assembly 720 to transfer the added weight to the drill bit 726, and in turn, to assist the drill bit 726 in penetrating the surface 704 and subsurface formations 714.

[0049] During drilling operations, a mud pump 732 may pump drilling fluid (sometimes known by those of skill in the art as “drilling mud”) from a mud pit 734 through a hose 736 into the drill pipe 718 and down to the drill bit 726. The drilling fluid can flow out from the drill bit 726 and be returned to the surface

704 through an annular area 740 between the drill pipe 718 and the sides of the borehole 712. The drilling fluid may then be returned to the mud pit 734, where such fluid is filtered. In some embodiments, the drilling fluid can be used to cool the drill bit 726, as well as to provide lubrication for the drill bit 726 during drilling operations. Additionally, the drilling fluid may be used to remove subsurface formation 714 cuttings created by operating the drill bit 726.

[0050] In some embodiments, the system 764 may include a display 796 to present casing wear information and sensor responses as measured by the sensors 700. This information can be used in steering the drill bit 726 during the drilling operation. The system 764 may also include computation logic, such as processors, perhaps as part of a surface logging facility 792, or a computer workstation 754, to receive signals from transmitters and receivers, and other instrumentation.

[0051] It should be understood that the apparatus and systems of various embodiments can be used in applications other than those described above. The illustrations of systems 664, 764 are intended to provide a general understanding of the structure of various embodiments, and they are not intended to serve as a complete description of all the elements and features of apparatus and systems that might make use of the structures described herein.

[0052] Although specific embodiments have been illustrated and described herein, it will be appreciated by those of ordinary skill in the art that any arrangement that is calculated to achieve the same purpose may be substituted for the specific embodiments shown. Various embodiments use permutations and/or combinations of embodiments described herein. It is to be understood that the above description is intended to be illustrative, and not restrictive, and that the phraseology or terminology employed herein is for the purpose of description. Combinations of the above embodiments and other embodiments will be apparent to those of skill in the art upon studying the above description.

CLAIMS

What is claimed is:

1. A method comprising:

determining values of casing and drill string variables and constants;

generating an estimate of casing wear based on the variables and constants;

determining when the estimate of casing wear has reached a threshold; and

stopping a drilling operation based on the estimate of casing wear reaching the threshold.

2. The method of claim 1, wherein determining the casing and drill string variables and constants comprises determining a load per unit width of a contacting element, a radii of curvature of the casing and a tool joint of the drill string, a modulii of elasticity of the casing and the tool joint of the drill string, and a Poisson's ratio of the casing and the tool joint of the drill string.

3. The method of claim 2, further comprising calculating the load per unit width of the contacting element based on an inclination and azimuth of the drill string.

4. The method of claim 2, further comprising estimating the casing wear by:

$$V = \pi 0.564 k F_n D_{tj} N L t \left[\frac{\dfrac{\left(\rho_c - \rho_{tj}\right)}{\rho_c \rho_{tj}}}{\left(\dfrac{1-\mu_c^2}{E_c}\right) + \left(\dfrac{1-v_{tj}^2}{E_{tj}}\right)} \right]^{\frac{1}{2}} \text{ inches}^3\text{/feet}$$

where N = rotary speed (revolutions per minute), D_{tj} = tool-joint diameter (inches), t = contact time (minutes), ρ_c, ρ_{tj} = radii of curvature of the casing and the tool joint, respectively, E_c , E_{tj} = modulii of elasticity of the casing and the tool joint, respectively, and $\nu_c, \nu_{tj} =$ Poisson's ratio of the casing and the tool joint, respectively.

5. The method of claim 4, further comprising determining the contact time, t, by $t = \frac{L \times L_{tj}}{ROP \times L_{dp}}$ minutes, where L = drilling distance (feet), L_{tj} = drilling distance of the tool joint (feet), L_{dp} = drilling distance of the drill string (feet); and ROP = rate of penetration into a geological formation (feet/minute).

6. The method of claim 1, further comprising reading data from downhole sensors during the drilling operation.

7. The method of claim 6, wherein determining when the estimate of casing wear has reached the threshold comprises:

dynamically updating the estimate of the casing wear in substantially real time using the data read from the downhole sensors; and

comparing each updated estimate of casing wear to the threshold.

8. A non-transitory machine-readable storage device having instructions stored thereon, which, when performed by a machine, cause the machine to perform operations, the operations comprising the method of claim 1.

9. A method comprising:

determining casing and drill string variables and constants comprising at least one of a load per unit width of a contacting element, a radii of curvature of the casing and a tool joint of a drill string, a modulii of elasticity of the casing and the tool joint of the drill string, and a Poisson's ratio of the casing and the tool joint of the drill string;

generating a first estimate of casing wear prior to conducting a first drilling operation;

conducting the first drilling operation and dynamically generating a second estimate of casing wear based on at least one of the variables and constants and downhole data;

determining when the second estimate of casing wear has reached a predetermined value; and

halting the first drilling operation based on the second estimate of casing wear reaching or exceeding the predetermined value.

10. The method of claim 9, further comprising reading the downhole data from sensors coupled to the drill string.

11. The method of claim 9, further comprising:

measuring actual casing wear after conducting the first drilling operation; and

updating the first estimate of casing wear, prior to conducting a second drilling operation, based on the measured actual casing wear.

12. The method of claim 11, further comprising updating the first estimate of casing wear based on reading drilling data from logs of the first drilling operation.

13. The method of claim 9, wherein generating the second estimate is based on a formula which embodies Hertzian contact mechanics.

14. A system comprising:

a sensor; and

a controller coupled to the sensor and configured to estimate casing wear during a drilling operation in response to a stress theory that dynamically generates the estimate of casing wear based on data received from the sensor and at least one of a load per unit width of a contacting element, a radii of curvature of the casing and a tool joint of a drill string, a modulii of elasticity of the casing and the tool joint of the drill string, and a Poisson’s ratio of the casing and the tool joint of the drill string determined prior to conducting the drilling operation.

15. The system of claim 14, further comprising a communications unit to receive data generated from the sensor disposed in a wellbore.

16. The system of claim 14, wherein the sensor includes one or more sensors comprising a fiber optic sensor, a pressure sensor, and/or a strain gauge to monitor drilling or production conditions associated with the wellbore.

17. The system of claim 14, wherein the controller is further configured to stop the drilling operation when the dynamically generated estimate of casing wear reaches a predetermined value.

18. The system of claim 17, wherein the predetermined value is indicated when the casing is thinner than a thickness threshold determined by a safety factor.

19. The system of claim 14, wherein the controller is further configured to access logs of statistical data associated with the drilling operation to gather statistical data regarding the drilling operation.

20. The system of claim 19, wherein the statistical data comprises a distance of drilling and/or a rotational speed of a drill string.

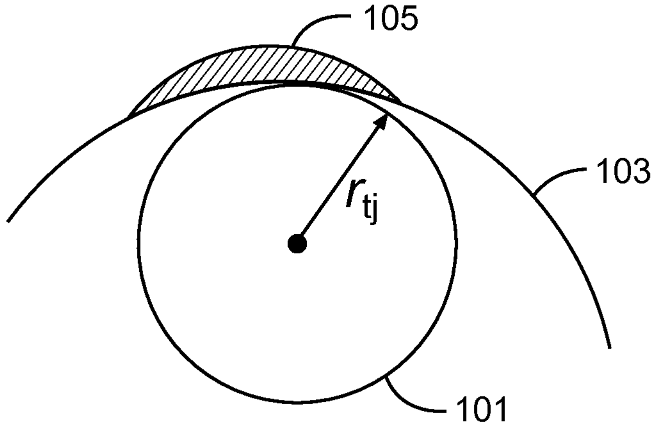

105
103
r_{tj}
101

Fig. 1

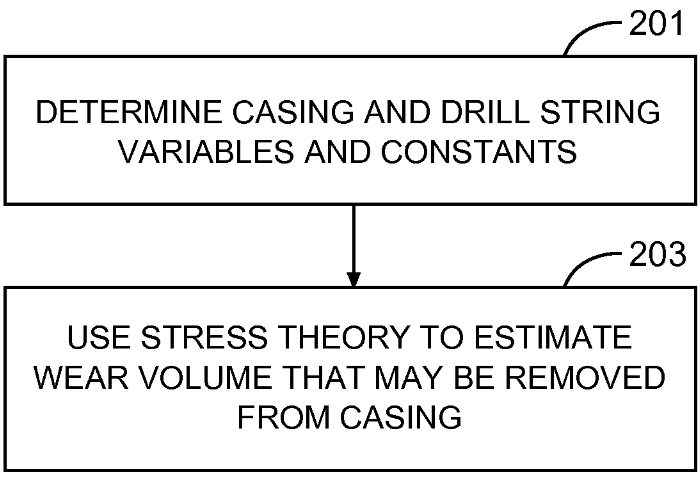

201
DETERMINE CASING AND DRILL STRING VARIABLES AND CONSTANTS
203
USE STRESS THEORY TO ESTIMATE WEAR VOLUME THAT MAY BE REMOVED FROM CASING

Fig. 2

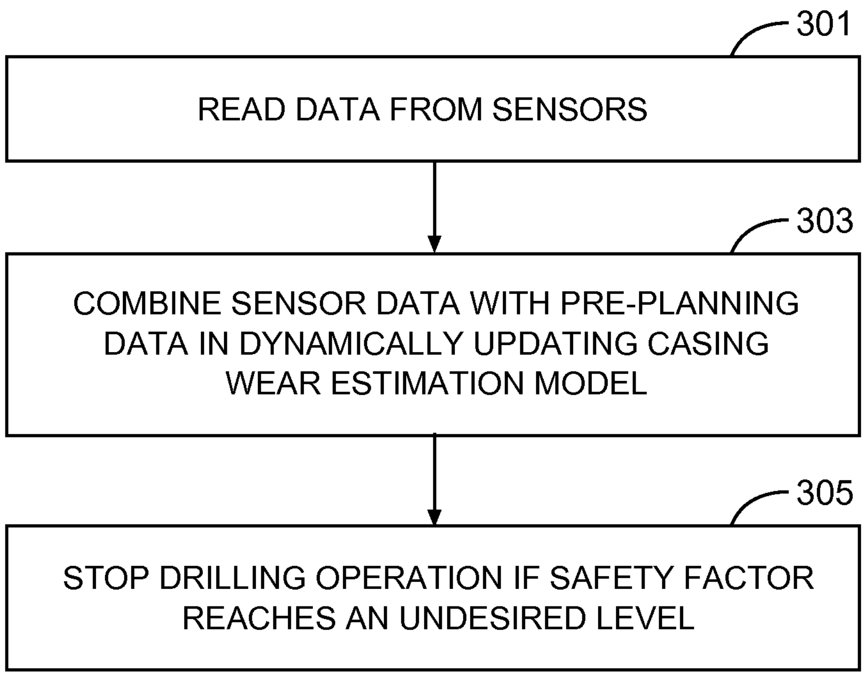

301
READ DATA FROM SENSORS
303
COMBINE SENSOR DATA WITH PRE-PLANNING DATA IN DYNAMICALLY UPDATING CASING WEAR ESTIMATION MODEL
305
STOP DRILLING OPERATION IF SAFETY FACTOR REACHES AN UNDESIRED LEVEL

Fig. 3

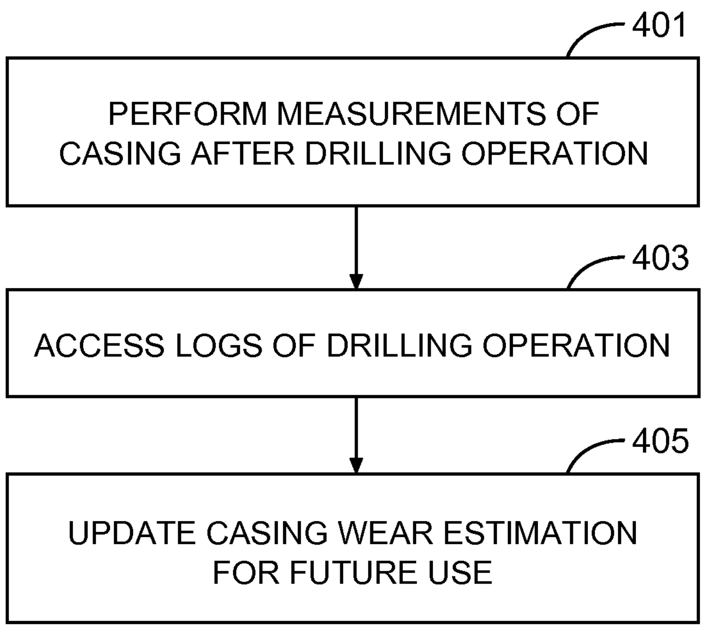
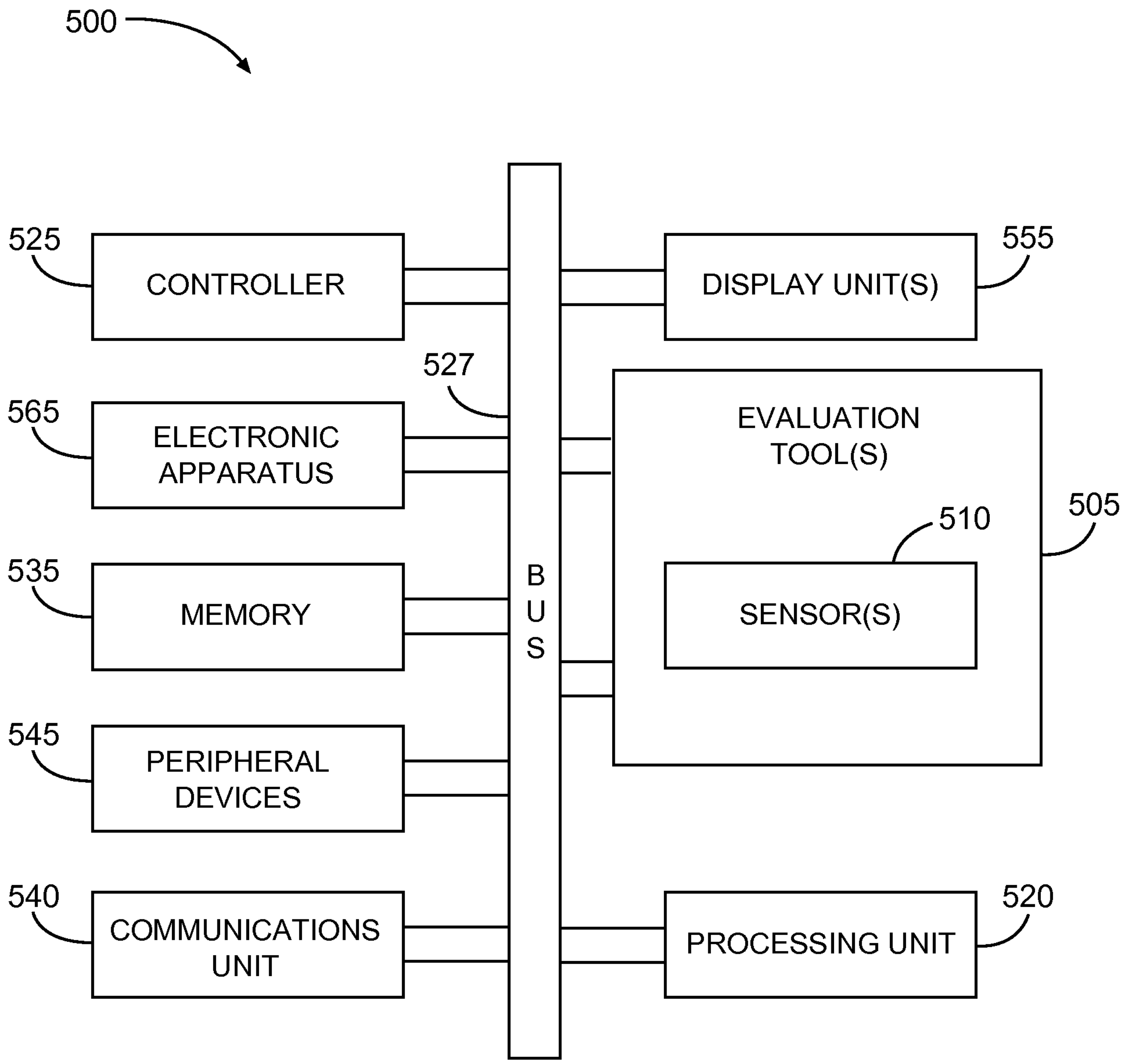

401
PERFORM MEASUREMENTS OF CASING AFTER DRILLING OPERATION
403
ACCESS LOGS OF DRILLING OPERATION
405
UPDATE CASING WEAR ESTIMATION FOR FUTURE USE

Fig. 4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CONTROLLER
555
DISPLAY UNIT(S)
527
565
ELECTRONIC APPARATUS
EVALUATION TOOL(S)
510
505
535
MEMORY
B U S
SENSOR(S)
545
PERIPHERAL DEVICES
540
COMMUNICATIONS UNIT
520
PROCESSING UNIT

Fig. 5

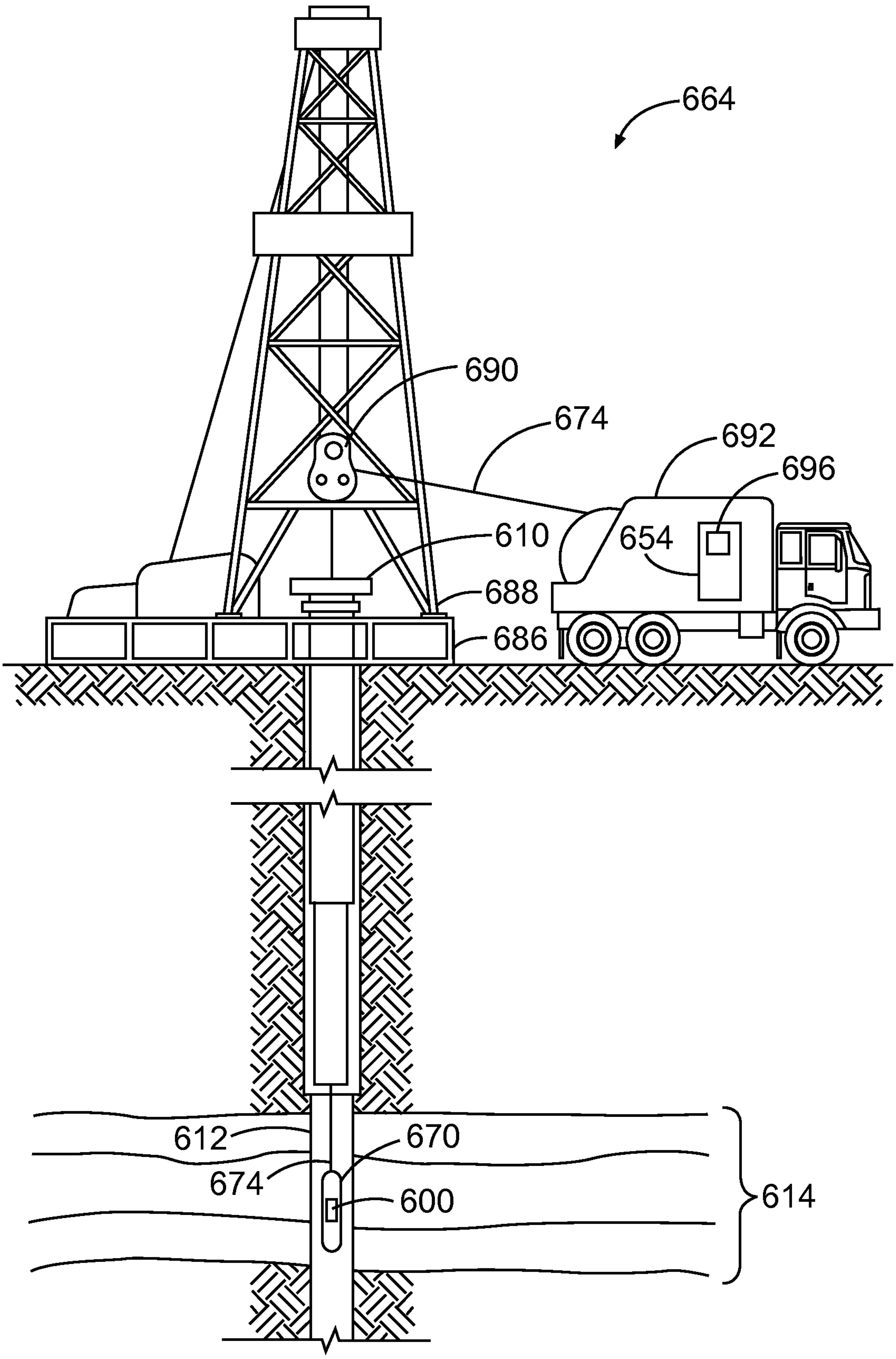

Fig. 6

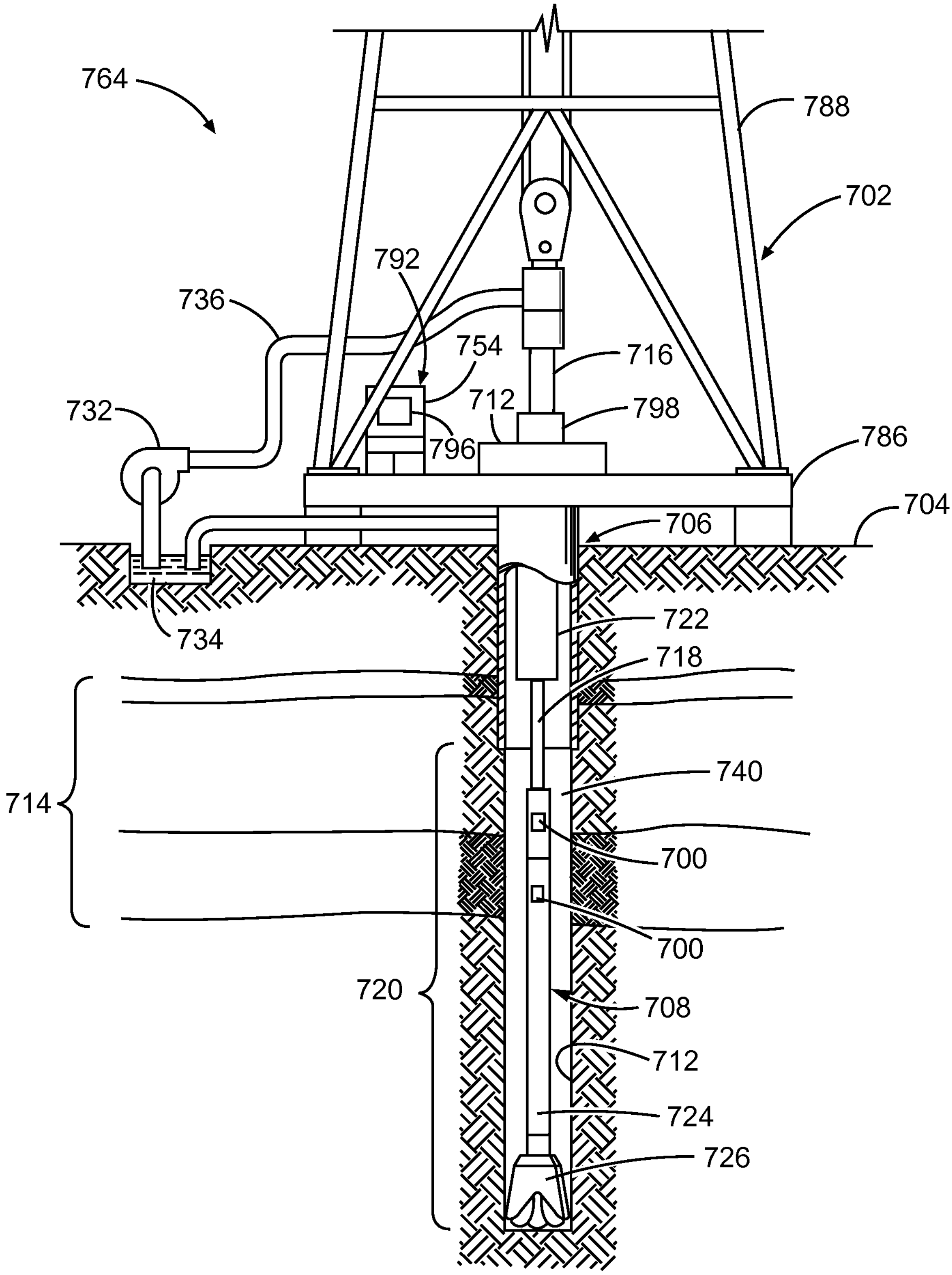
764
788
702
792
736
754
716
712
798
732
796
786
704
706
734
722
718
740
714
700
700
720
708
712
724
726

Fig. 7

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2014/010041

A. CLASSIFICATION OF SUBJECT MATTER

E21B 12/02(2006.01)i, E21B 47/024(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 12/02; E21B 7/00; E21B 25/16; G01N 27/72; E21B 47/022; G01N 3/56; E21B 7/04; G01V 1/40; E21B 17/00; E21B 47/024

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:casing thickness, casing wear, estimation, sensor, controller, and stress theory

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 4573540 A (DELLINGER et al.) 04 March 1986 See column 3, line 45 - column 4, line 57.	1,6-7
Y		8-12,14-20
A		2-5,13
Y	US 2010-0037675 A1 (HANNAHS et al.) 18 February 2010 See paragraphs [0005]-[0006], [0028], [0033], [0040] and figures 1, 4.	8-12,14-20
A	US 2010-0044110 A1 (BANGRU et al.) 25 February 2010 See paragraphs [0041]-[0045] and figure 2.	1-20
A	US 6316937 B1 (EDENS, BRIAN WADE) 13 November 2001 See column 4, line 59 - column 6, line 55, claims 1-5, and figures 1, 3-4.	1-20
A	US 7346455 B2 (WARD et al.) 18 March 2008 See column 8, line 5 - column 10, line 13, column 14, lines 37-54, claim 23, and figures 1-2, 13.	1-20

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

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
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"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
20 October 2014 (20.10.2014)

Date of mailing of the international search report
20 October 2014 (20.10.2014)

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