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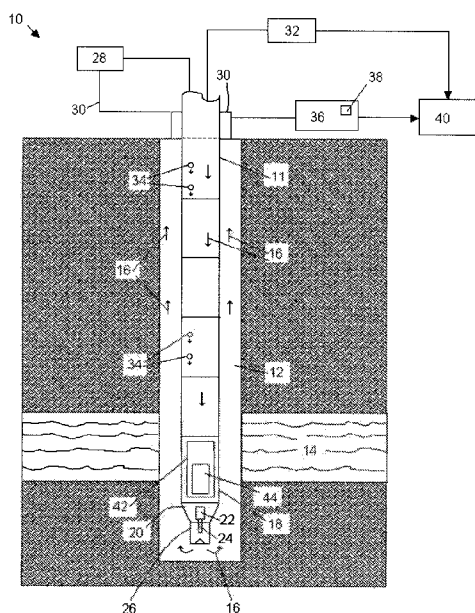


FIG. 1

(57) Abstract: An apparatus for estimating a parameter of a borehole disposed in an earth formation, the system includes: an injection unit configured to inject at least one radio frequency identification device (RFID) into a fluid configured to be disposed in the borehole; and a collection unit configured to receive at least a portion of the fluid, the collection unit comprising a detector that detects at least one of the at least one RFID and data contents thereof; wherein the detector provides output for estimating the parameter. A method for estimating a parameter of a borehole is also disclosed.

**SYSTEM AND METHOD FOR MONITORING VOLUME AND FLUID
FLOW OF A WELLBORE**

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BACKGROUND

5 **[0001]** During hydrocarbon drilling and recovery operations, a drilling fluid is injected into a drillstring as a wellbore is drilled through an earth formation or through pre-existing equipment installed in that borehole. The drilling fluid or “mud” circulates through the drillstring, exiting through orifices, also known as “nozzles” or “jets”, into the wellbore annulus. That drilling fluid then passes from the bottom of
10 the hole or exit point through the wellbore annulus between the wall of the hole and the outside diameter of the drillstring and then onwards to the surface where the returning fluid is recovered for treatment or disposal.

[0002] Material cut from the formation during drilling, known as drill cuttings, can be evaluated to determine various characteristics of the discreet layers of the formation
15 being penetrated, such as lithology, mineralogy including trace minerals, fossil or other organic content, petrophysical & geophysical characteristics, as well as any residual hydrocarbon, gas, or other fluid contents trapped in the pore space of the formation. In addition, the destruction of the formation by the drill bit or other drilling and hole enlarging tools results in the pore contents of the formation being
20 released into the mud as “mud gas”. Mud gas may be in liquid form under downhole pressure and temperature conditions, but the liquid form may change to gaseous form during the transition from the wellbore annulus to the atmospheric conditions at the surface. Examples of “mud gas” include hydrocarbons, such as the alkanes including methane, ethane, propane and others; “acidic” gases such as carbon dioxide and
25 hydrogen sulphide; and noble gases such as helium, nitrogen, argon, etc. Other fluids trapped in the pore spaces of the formation such as oil and water, which may contain salts such as chlorides, may influence characteristics such as other chemical components, temperature, pressure, weight and viscosity of the mud. Such evaluation of solids, liquids, gases and mud conditions is generally referred to as “mud logging”.

30 **[0003]** The volume of the wellbore annulus varies continuously while drilling progresses due to planned and incidental variations in wellbore diameter, changes in

- the drillstring configuration and its external diameters and lengths. The time to displace the contents of the wellbore annulus varies by the volumetric rate and location at which fluid is pumped into the drillstring, the quantity exiting the well and returning to the surface systems, the mud type and conditions, and any interactions
- 5 between the solids, liquids and gases from the formations penetrated or exposed in the wellbore, and the drilling fluid used to drill or complete the well. The individual times for solids, liquids and gases being displaced in a wellbore further varies by the density, shape, and surface and physio-chemical characteristics of the formation and the contents of its pore spaces.
- 10 **[0004]** Mud logging requires accurate knowledge of the annular volume in a wellbore in order to accurately reconstruct the lithological and formation fluid components at the drill bit, based on samples which are recovered over time from the drilling fluid at the surface. One method of quantifying the annular volume involves the use of “tracers”, i.e., non-reactive and detectable alien material inserted into the
- 15 drilling fluid at the surface during a pumping operation. The tracer is moved from the drillstring annulus into the wellbore annulus and then returns to the surface where it detected and /or recovered.
- [0005]** Current tracer technology involves adding a quantity of calcium carbide in the form of a “pill” that reacts to form acetylene in contact with water, or adding a stream
- 20 of acetylene or similar detectable alien gas, fluid or solid to the drilling fluid. The tracer is added at the surface, and its return is identified using a mud logging gas detection system or other sensors installed at the surface and in contact with the drilling fluid. An annular volume is estimated from the time duration between injector to detector, and the resultant volume displaced by the mud pumps during that
- 25 duration. The tracers may be recycled over several displacements of the annular volume until they become undetectable. However, this technique offers potential confusion about which tracers are actually being detected, compromising the accuracy of the volume estimate.

SUMMARY

[0006] Disclosed is an apparatus for estimating a parameter of a borehole disposed in an earth formation, the system includes: an injection unit configured to inject at least one radio frequency identification device (RFID) into a fluid configured to be disposed in the borehole; and a collection unit configured to receive at least a portion of the fluid, the collection unit comprising a detector that detects at least one of the at least one RFID and data contents thereof; wherein the detector provides output for estimating the parameter.

[0007] Also disclosed is a method of estimating a parameter of a borehole disposed in an earth formation, the method includes: injecting at least one radio frequency identification device (RFID) in a fluid configured to be disposed in the borehole; circulating the fluid through the borehole and receiving at least a portion of the fluid in a collection unit; detecting at least one of the at least one RFID device and data contents thereof with a detector in the collection unit; and providing output from the detector for estimating the parameter.

BRIEF DESCRIPTION OF THE DRAWINGS

[0008] The following descriptions should not be considered limiting in any way. With reference to the accompanying drawings, like elements are numbered alike:

FIG. 1 depicts an embodiment of a well logging and/or drilling system;
FIG. 2 is a flow chart providing an exemplary method of measuring a fluid volume through a borehole; and
FIG. 3 is an illustration of a system for measuring a fluid volume through a borehole.

DETAILED DESCRIPTION OF THE INVENTION

[0009] Referring to **FIG. 1**, an exemplary embodiment of a well logging and/or drilling system **10** includes a drillstring **11** that is shown disposed in a borehole **12** that penetrates at least one earth formation **14** during a drilling, well logging and/or hydrocarbon production operation. The drillstring **11** includes a drill pipe, which may be one or more pipe sections or coiled tubing. The well drilling system **10** also

includes a bottomhole assembly (BHA) **18**. A borehole fluid **16** such as a drilling or completion fluid or drilling mud may be pumped through the drillstring **11**, the BHA **18** and/or the borehole **12**. The drilling or completion fluid is liquid and/or gaseous.

[0010] As described herein, “borehole” or “wellbore” refers to a single hole that makes up all or part of a drilled well. As described herein, “formations” refer to the various features and materials that may be encountered in a subsurface environment. Accordingly, it should be considered that while the term “formation” generally refers to geologic formations of interest, that the term “formations,” as used herein, may, in some instances, include any geologic points or volumes of interest (such as a survey area). Furthermore, various drilling or completion service tools may also be contained within this borehole or wellbore, in addition to formations. In addition, it should be noted that “drillstring” as used herein, refers to any structure suitable for lowering a tool through a borehole or connecting a drill bit to the surface, and is not limited to the structure and configuration described herein. For example, the drillstring **11** is configured as a hydrocarbon production string.

[0011] In one embodiment, the BHA **18** includes a drilling assembly having a drill bit assembly **20** and associated motors adapted to drill through earth formations. In one embodiment, the drill bit assembly **20** includes a steering assembly including a steering motor **22** configured to rotationally control a shaft **24** connected to a drill bit or drilling tool **26**. The shaft is utilized in drilling and milling operations to steer the drill bit **26** and the drillstring **11** through the formation **14** or through pre-existing drilling or completion service tools.

[0012] During drilling operations, the drilling fluid **16** is introduced into the drillstring **11** from a mud tank or “pit” **28** or other source of drilling fluid **16**, which may be liquid and/or gaseous, and is circulated under pressure through the drillstring **11**, for example via one or more mud pumps. The drilling fluid **16** passes into the drillstring **11** and is discharged at the bottom of the borehole through an opening in the drill bit or drilling tool **26**. The drilling fluid **16** circulates uphole between the drill string **11** and the borehole **12** and is discharged into, for example, the mud tank **28** via a return flow line **30**.

[0013] The system 10 includes a tracer system for calculating a circulation time of the drilling fluid 16 through the borehole 12, which is in turn utilized to calculate the fluid volume. In one embodiment, an effective volume of the drillstring 11 and the borehole 12 is calculated using the time duration taken from injection to detection and
5 the volume displaced by the mud pumps during that duration. As used herein, the fluid may include drilling fluid 16 which may be liquid or gaseous, as well as any combination of gases, hydrocarbons and cuttings or millings from the drill bit and the formation 14, and is accordingly referred to hereafter as “borehole fluid” 16.

[0014] The tracer system includes an injection unit 32 including at least one Radio
10 Frequency Identification Device (“RFID”) 34. The RFID 34 has known characteristics and may potentially be a plurality of RFIDs of the same or different sizes. The injection unit 32, in one embodiment, is disposed at a surface location, such as in fluid communication with a suction tank included in a drilling rig connected to the drillstring 11. In other embodiments, the injection unit 32 is
15 configured to inject the RFID 34 at any selected location along the length of the drillstring 11.

[0015] In one embodiment, the RFID 34 is in the nano-scale. In another embodiment, the RFID 34 is a microelectromechanical system device (“MEMS”) incorporated in a MEMS system. For example, a MEMS system includes a plurality of MEMS devices
20 each incorporating an RFID 34. Such MEMS particles are referred to as “smart dust”. Using a plurality of RFIDs 34, such as in a smart dust system, with different signatures and particle sizes enables a more complete annular profile and displacement rates to be mapped.

[0016] In one embodiment, the MEMS devices are sensors configured to measure
25 physico-chemical properties of the drillstring 11, the borehole 12 and/or the formation 14, and carry data corresponding to these properties to a surface detection system. Examples of such physico-chemical properties include pressure, temperature and chemical composition.

[0017] In one embodiment, the MEMS devices or smart dust are incorporated into a
30 fluid additive configured to be injected into a drilling or completion fluid or other

borehole fluid. In this embodiment, the smart dust is included in the fluid additive prior to injection into the borehole fluid.

5 [0018] The tracer system further includes a collection unit 36 that receives at least a portion of the borehole fluid 16. A detector 38 is disposed within the collection unit 36 and includes an antenna and suitable electronics to emit an electromagnetic detection signal into the borehole fluid 16. In one embodiment, the detector 38 is disposed at any suitable location, such as on the return flow line 30. In this embodiment, the collection unit 36 forms a portion of the return flow line 30, and the detector detects the RFID 34 as it passes through the return flow line 30.

10 [0019] Each RFID 34 includes a processing chip or other electronics unit and an antenna configured to receive the detection signal and emit a return signal identifying the RFID 34. For example, each RFID 34 is programmed with a unique identification number or batch number that is sent to the detector 38 in the return signal. The data associated with the return signal, in one embodiment, is transmitted to a suitable
15 processor such as a surface processing unit 40. The processor identifies the detected RFID 34, calculates a circulation time from the difference between the time that the RFID 34 is injected into the drilling fluid 16 and the time that the RFID 34 is detected.

[0020] In one embodiment, the tracer system and/or the BHA 18 are in
20 communication with the surface processing unit 40. In one embodiment, the surface processing unit 40 is configured as a surface drilling control unit which controls various production and/or drilling parameters such as rotary speed, weight-on-bit, fluid flow parameters, pumping parameters and others and records and displays real-time drilling performance and/or formation evaluation data. In addition, the surface
25 processing unit may be configured as a tracer system control unit and control the injection of the RFID 34 remotely. The BHA 18 and/or the tracer system incorporates any of various transmission media and connections, such as wired connections, fiber optic connections, wireless connections and mud pulse telemetry.

[0021] In one embodiment, the surface processing unit 40 includes components as
30 necessary to provide for storing and/or processing data collected from the injection unit 32 and/or the collection unit 36. Exemplary components include, without

limitation, at least one processor, storage, memory, input devices, output devices and the like.

[0022] The BHA 18, in one embodiment, includes a downhole tool 42. In one embodiment, selected components of the tracer system are incorporated into the downhole tool 42, such as the injection unit 32, to allow the travel time of the fluid between the drill bit assembly 20 and the surface to be calculated.

[0023] In one embodiment, the downhole tool 42 includes one or more sensors or receivers 44 to measure various properties of the borehole environment, including the formation 14 and/or the borehole 12. Such sensors 44 include, for example, nuclear magnetic resonance (NMR) sensors, resistivity sensors, porosity sensors, gamma ray sensors, seismic receivers and others. Such sensors 44 are utilized, for example, in logging processes such as measurement-while-drilling (MWD) and logging-while-drilling (LWD) processes.

[0024] Although the tracer system is described in conjunction with the drillstring 11, the tracer system may be used in conjunction with any structure suitable to be lowered into a borehole, such as a production string or a wireline.

[0025] FIG. 2 illustrates a method 50 of measuring a fluid volume through a borehole. The method 50 is used in conjunction with the tracer system and the surface processing unit 40, although the method 50 may be utilized in conjunction with any suitable combination of processors and systems incorporating RFID devices. The method 50 includes one or more stages 51, 52, 53, 54 and 55. In one embodiment, the method 50 includes the execution of all of stages 51-55 in the order described. However, certain stages may be omitted, stages may be added, or the order of the stages changed.

[0026] In the first stage 51, the drillstring 11 is introduced into the borehole 12 and borehole fluid 16 is introduced into the drillstring 11.

[0027] In the second stage 52, at least one RFID 34 is injected into the borehole fluid 16 from the injection unit 32. A location and time of the injection is noted and, in one embodiment, transmitted to a suitable processor.

[0028] In the third stage 53, the borehole fluid 16 is circulated through the drillstring 11 and returns to the surface through the borehole 12. A portion of the borehole fluid 16 is collected by the collection unit 36. At this point, the borehole fluid 16 may include drill bit cuttings, water, gas, hydrocarbons, formation material and/or other materials.

[0029] In the fourth stage 54, the RFID 34 is detected in the collection unit 36. In one embodiment, the time of detection is noted and transmitted to the processor.

[0030] In the fifth stage 55, a circulation time between injecting the at least one RFID 34 and detecting the at least one RFID 34 is calculated, and a borehole fluid volume is calculated based on the circulation time. This volume may include the volume of fluid within the drillstring 11 and/or the annular volume of fluid between the drillstring 11 and the walls of the borehole 12. For example, if the flow rate of fluid introduced into the borehole 12 is known, such as the volumetric flow of fluid through a mud pump, the circulation time of the RFID 34 is used to determine a total fluid volume in the borehole 12.

[0031] Referring to FIG. 3, there is provided a system 60 for measuring the time taken for a fluid volume to be displaced through a borehole and/or calculating a volume of the drillstring 11 and/or the wellbore 12. The system may be incorporated in a computer 61 or other processing unit capable of receiving data from the injection unit 32 and/or the detector 38. Exemplary components of the system 60 include, without limitation, at least one processor, storage, memory, input devices, output devices and the like. As these components are known to those skilled in the art, these are not depicted in any detail herein.

[0032] Generally, some of the teachings herein are reduced to instructions that are stored on machine-readable media. The instructions are implemented by the computer 61 and provide operators with desired output.

[0033] The systems and methods described herein provide various advantages over prior art techniques. In contrast to calcium carbide tracers, the tracers described herein do not need to be introduced on a well rig floor, and can rather be introduced into a rig's suction tank or from downhole sources within the drillstring or bottom hole assembly automatically and/or remotely without the need for human manual

intervention. In addition, tracers described herein can be differentiated by size, physical characteristics or electronic characteristics, eliminating any confusion as to which tracers are being detected. These tracers may also be able to measure and carry data to reflect the ambient environment through which they have passed.

- 5 [0034] In support of the teachings herein, various analyses and/or analytical components may be used, including digital and/or analog systems. The system may have components such as a processor, storage media, memory, input, output, communications link (wired, wireless, pulsed mud, optical or other), user interfaces, software programs, signal processors (digital or analog) and other such components
- 10 (such as resistors, capacitors, inductors and others) to provide for operation and analyses of the apparatus and methods disclosed herein in any of several manners well-appreciated in the art. It is considered that these teachings may be, but need not be, implemented in conjunction with a set of computer executable instructions stored on a computer readable medium, including memory (ROMs, RAMs), optical (CD-
- 15 ROMs), or magnetic (disks, hard drives), or any other type that when executed causes a computer to implement the method of the present invention. These instructions may provide for equipment operation, control, data collection and analysis and other functions deemed relevant by a system designer, owner, user or other such personnel, in addition to the functions described in this disclosure.
- 20 [0035] Further, various other components may be included and called upon for providing aspects of the teachings herein. For example, a sample line, sample storage, sample chamber, sample exhaust, filtration system, pump, piston, power supply (e.g., at least one of a generator, a remote supply and a battery), vacuum supply, pressure supply, refrigeration (i.e., cooling) unit or supply, heating
- 25 component, motive force (such as a translational force, propulsional force or a rotational force), magnet, electromagnet, sensor, electrode, transmitter, receiver, transceiver, controller, optical unit, electrical unit or electromechanical unit may be included in support of the various aspects discussed herein or in support of other functions beyond this disclosure.
- 30 [0036] Elements of the embodiments have been introduced with either the articles “a” or “an.” The articles are intended to mean that there are one or more of the elements. The terms “including” and “having” and their derivatives are intended to be inclusive

such that there may be additional elements other than the elements listed. The conjunction “or” when used with a list of at least two terms is intended to mean any term or combination of terms.

5 [0037] One skilled in the art will recognize that the various components or technologies may provide certain necessary or beneficial functionality or features. Accordingly, these functions and features as may be needed in support of the appended claims and variations thereof, are recognized as being inherently included as a part of the teachings herein and a part of the invention disclosed.

10 [0038] While the invention has been described with reference to exemplary embodiments, it will be understood by those skilled in the art that various changes may be made and equivalents may be substituted for elements thereof without departing from the scope of the invention. In addition, many modifications will be appreciated by those skilled in the art to adapt a particular instrument, situation or material to the teachings of the invention without departing from the essential scope
15 thereof. Therefore, it is intended that the invention not be limited to the particular embodiment disclosed as the best mode contemplated for carrying out this invention, but that the invention will include all embodiments falling within the scope of the appended claims.

CLAIMS

- 1 1. An apparatus for estimating a parameter of a borehole disposed in an
2 earth formation, the system comprising:
3 an injection unit configured to inject at least one radio frequency identification
4 device (RFID) into a fluid configured to be disposed in the borehole; and
5 a collection unit configured to receive at least a portion of the fluid, the
6 collection unit comprising a detector that detects at least one of the at least one RFID
7 and data contents thereof;
8 wherein the detector provides output for estimating the parameter.
- 1 2. The apparatus of claim 1, further comprising a processor in operable
2 communication with at least one of the injection unit and the detector, the processor
3 configured to calculate a circulation time between injection of the at least one RFID
4 into the borehole fluid and detection of the at least one RFID by the detector and to
5 calculate a volume of the borehole.
- 1 3. The apparatus of claim 1, wherein the collection unit is located at a
2 surface location.
- 1 4. The apparatus of claim 1, wherein the at least one RFID is a plurality
2 of RFIDs.
- 1 5. The apparatus of claim 4, wherein each RFID in the plurality is a
2 microelectromechanical system (MEMS) device.
- 1 6. The apparatus of claim 4, wherein each RFID in the plurality is
2 configured to emit a unique identification signal to the detector.
- 1 7. The apparatus of claim 1, wherein the injection unit is disposed in at
2 least one of a surface location and a downhole location.
- 1 8. The apparatus of claim 1, further comprising a bottomhole assembly
2 (BHA) including a drill bit assembly, the bottomhole assembly incorporating the
3 injection unit therein.

1 9. The apparatus of claim 1, wherein the parameter is an annular volume
2 between a borehole assembly and the borehole, the borehole assembly being
3 configured to be disposed along a length of the borehole and to receive the fluid
4 therein.

1 10. The apparatus of claim 1, further comprising a return conduit located at
2 a surface location and in fluid communication with an annular portion of the borehole.

1 11. The apparatus of claim 10, wherein the collection unit forms a selected
2 portion of the return conduit and the detector is disposed on the selected portion.

1 12. The apparatus of claim 1, wherein the collection unit comprises an
2 antenna and an electronics unit configured to emit an electromagnetic detection signal
3 into the collection unit.

1 13. The apparatus of claim 12, wherein the at least one RFID comprises a
2 processing unit and an antenna configured to receive the detection signal and emit a
3 return signal identifying the at least one RFID and data contents thereof.

1 14. A method of estimating a parameter of a borehole disposed in an earth
2 formation, the method comprising:
3 injecting at least one radio frequency identification device (RFID) in a fluid
4 configured to be disposed in the borehole;
5 circulating the fluid through the borehole and receiving at least a portion of the
6 fluid in a collection unit;
7 detecting at least one of the at least one RFID and data contents thereof with a
8 detector in the collection unit; and
9 providing output from the detector for estimating the parameter.

1 15. The method of claim 14, further comprising introducing a drillstring
2 into the borehole and introducing the fluid into the drillstring.

1 16. The method of claim 15, wherein circulating comprises circulating the
2 fluid through the drillstring and the borehole.

- 1 15. The method of claim 16, further comprising measuring a circulation
2 time between injecting the at least one RFID and detecting the at least one RFID and
3 estimating a volume of the borehole using the circulation time.
- 1 16. The method of claim 15, wherein the volume is an annular volume
2 between the drillstring and the borehole.
- 1 17. The method of claim 14, wherein the at least one RFID device is
2 injected at a location selected from at least one of a surface location and a downhole
3 location.
- 1 18. The method of claim 14, wherein the collection unit is in fluid
2 communication with a return conduit located at a surface location and in fluid
3 communication with an annular portion of the borehole.
- 1 19. The method of claim 18, wherein the detector is disposed on a portion
2 of the return conduit.
- 1 20. The method of claim 14, wherein the detecting comprises emitting an
2 electromagnetic detection signal into the collection unit and causing the at least one
3 RFID device to emit a return signal for identifying at least one of the at least one
4 RFID and the data contents thereof.

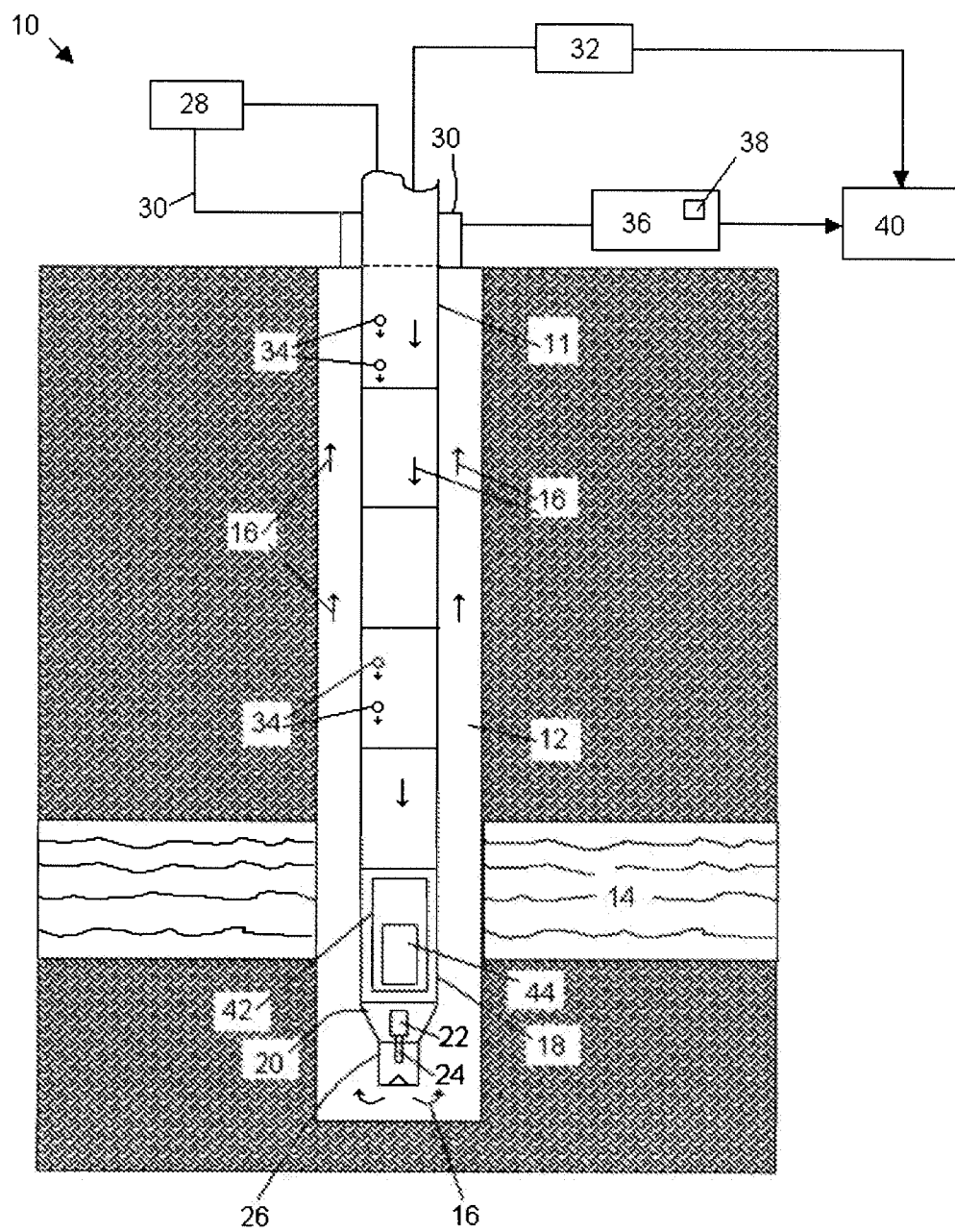


FIG. 1

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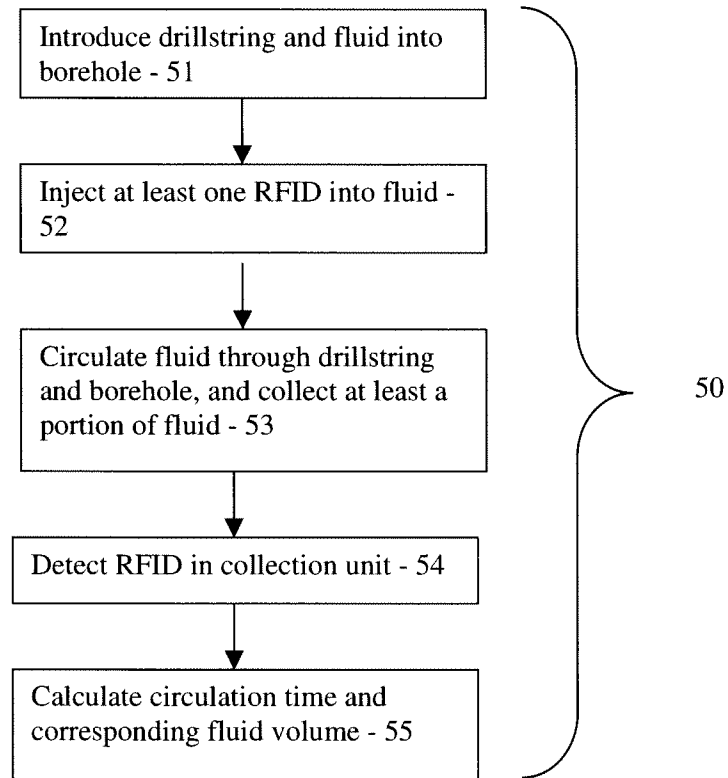


FIG. 2

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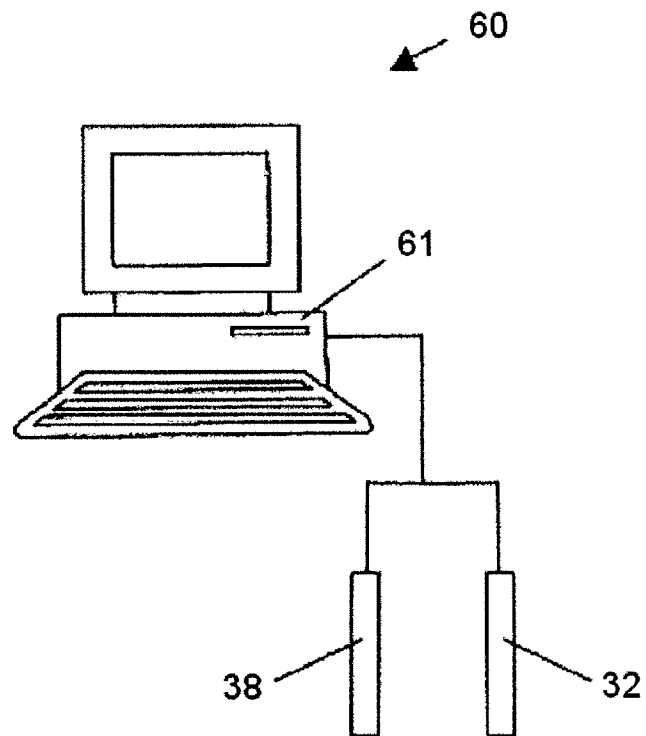


FIG. 3