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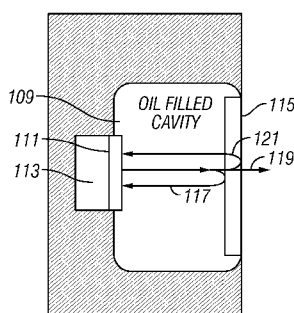
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(54) Title: EARLY KICK DETECTION IN AN OIL AND GAS WELL



(57) Abstract: An acoustic transducer on a downhole tool sends an acoustic wave through a sensor plate in contact with drilling fluid. Vibrations of the sensor plate are indicative of the impedance of the borehole plate that may be associated with gas influx. A processor analyzes the vibrations and uses an estimated Q of the vibrations to determine gas influx.



WO 2008/024807 A2

EARLY KICK DETECTION IN AN OIL AND GAS WELL

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5 BACKGROUND OF THE DISCLOSURE

1. Field of the Disclosure

[0001] This disclosure relates generally to oil and gas well logging tools. More particularly, this disclosure relates to tools and methods for identifying the influx of gas into the borehole in real-time during drilling operations

10

2. Description of the Related Art

[0002] Exploration for hydrocarbons commonly includes using a bottomhole assembly including a drill-bit for drilling a borehole in an earth formation. Drilling fluid or "mud" used in the drilling may vary in density or "mud weight" for a number of reasons. Such variations can result from changes in the quantity and density of cuttings (particles of formation); changes in the "mud program" at the surface, changes in temperature, etc. Variations in mud density also occur when gas or liquid enter the borehole from the formation. Such influx of formation fluids may likely be the result of formation overpressures or abnormally high pressures.

20

[0003] Pressure detection concepts are especially important in drilling. Not only does the drilling rate decrease with a high overbalance of mud pressure versus formation pressure, but also lost circulation and differential pressure sticking of the drill pipe can readily occur. More importantly, an underbalance of mud pressure versus formation pressure can cause a pressure "kick." A well may kick without forewarning. Balanced drilling techniques often require only a fine margin between effective pressure control and a threatened blowout. Additionally, there are situations where underbalance is maintained to avoid formation damage so that it is important to detect inflow of formation liquids into the borehole.

30

[0004] Some prior art techniques for detecting abnormal formation pressure are based on measurement of drilling parameters such as drilling rate, torque and drag; drilling mud parameters such as mud gas cuttings, flow line mud weight, pressure kicks, flow line temperature, pit level and pit volume, mud flow rate; shale cutting parameters

such as bulk density, shale factor, volume and size of cuttings. All of these suffer from the drawback that the measurements are not available in real-time as they must wait for the bottom hole fluid to reach the surface.

5 **[0005]** Other prior art methods for identifying possible kicks rely on density measurements of the borehole fluid. See, for example, US4492865 to *Murphy* et al, US4412130 to *Winters*, US6648083 to *Evans* et al., and US6768106 to *Gzara* et al. A drawback of methods that make density measurements is that gas must be present in sufficient quantities to affect the density of the mud, so that dissolved gas that may be
10 a precursor to a gas kick would not register with conventional density measuring devices. In addition, the density measurements made by the prior art devices are responsive to varying degrees to the density of the formation. They also require the use of a radioactive source - a safety hazard during drilling operations.

15 **[0006]** There is a need for a technique to measure the properties of the borehole fluid downhole with a single tool in order to detect kicks and inflow of formation liquids. The present disclosure satisfies this need.

SUMMARY OF THE DISCLOSURE

20

[0007] One embodiment of the disclosure is an apparatus for detection of gas influx in a borehole fluid during drilling operations. The apparatus includes a bottomhole assembly (BHA) configured to be conveyed in a borehole. The BHA includes at least one transducer assembly which has a sensor plate in contact with the borehole fluid
25 and a cavity disposed between a transducer and the sensor plate. The transducer is configured to generate acoustic vibrations in the sensor plate. The apparatus includes a processor configured to estimate from a signal indicative of the acoustic vibrations an impedance of the borehole fluid, and to use the estimated fluid impedance to provide an indication of the gas influx. The cavity may include a fluid having a
30 known density and compressional velocity. The signal indicative of the acoustic vibrations may be provided by the transducer and/or a receiver. A sensor plate may have an acoustic impedance selected to match an expected impedance of the borehole fluid. The processor may be configured to estimate the impedance of the borehole fluid by determining a quality factor of the acoustic vibrations. The processor may be

configured to provide the indication of gas influx using a table lookup. The apparatus may further include a device configured to measure a P-wave velocity in the borehole fluid, and wherein the processor may be configured to provide the indication of gas influx using a density derived from the estimated fluid impedance and the measured

5 P-wave velocity. The sensor plate may be made of a material selected from a polyamide, a polymethylpentene, pyrolitic graphite, titanium, and/or aluminum. The at least one transducer assembly may include a plurality of transducer assemblies in electrical communication.

- 10 **[0008]** One embodiment of the present disclosure is a method of detecting a gas influx from the formation during drilling of a borehole. The method includes conveying a BHA including at least one transducer assembly into the borehole. A transducer on a first side of the cavity in the transducer assembly is used to generate acoustic vibrations in a sensor plate on a second side of the cavity, the sensor plate being in
- 15 contact with the borehole fluid. The method further includes estimating from a signal indicative of the acoustic vibrations an impedance of the borehole fluid, and using the estimated fluid impedance to provide an indication of the gas influx. The method may further include having a fluid with a known density and knowing compressional velocity in the cavity. The signal indicative of the acoustic vibrations may be
- 20 provided using the transducer and/or a receiver. The method may further include selecting a material for the sensor plate that has an acoustic impedance which matches an expected impedance of the borehole fluid. Estimation of the impedance of the borehole fluid may be done by determining a quality factor of the acoustic vibrations. A table lookup may be used to provide the indication of gas influx. The method may
- 25 further include measuring a P-wave velocity in the borehole fluid, and providing the indication of gas influx may further use a density derived from the estimated fluid impedance and the measured P-wave velocity. The method may further include electing a material for the sensor plate from a polyamide, a polymethylpentene, pyrolitic graphite, titanium, and/or aluminum. The method may further include
- 30 providing an absorptive backing on a backside of the transducer to reduce reflections. A plurality of transducer assemblies in electrical communication may be used. Providing the indication of gas influx may further include providing an alarm signal when the estimated fluid impedance changes by more than a specified threshold value relative to the estimated fluid impedance in an earlier interval.

[0009] Another embodiment of the disclosure is a computer readable medium for use with an apparatus for detecting a gas influx from the formation during drilling of a borehole. The apparatus includes a bottomhole assembly configured to be conveyed
5 in a borehole, a transducer assembly on the BHA that includes a sensor plate in contact with the borehole fluid, and a cavity between a transducer and the sensor plate, the transducer being configured to generate acoustic vibrations in the sensor plate. The medium includes instructions that enable a processor to estimate from a signal indicative of the acoustic vibrations an impedance of the borehole fluid, and
10 use the estimated fluid impedance to provide an indication of the gas influx. The medium may include a ROM, an EPROM, a flash memory and/or an optical disk

BRIEF DESCRIPTION OF THE DRAWINGS

[0010] The present disclosure is best understood with reference to the accompanying
15 figures in which like numerals refer to like elements and in which:

FIG. 1 (Prior Art) shows a measurement-while-drilling tool suitable for use with the present disclosure;

FIG. 2 is a cross sectional view of a measurement sub of the present disclosure;

20 FIG. 3 is a detailed sectional view of the acoustic transducer in Figure 2;

FIGS. 4a and 4b show exemplary signals using the acoustic transducer of Figure 2 when the impedance of the borehole fluid is (a) close to that of the sensor plate, and (b) different from that of the sensor plate;

FIG. 5 (prior art) shows modeled bulk moduli of fluid mixtures as a function
25 of density using a model of Batzle & Wang as calculated in the thesis of Terra Bulloch; and

FIG. 6 shows an embodiment of the disclosure in which a plurality of acoustic transducers are disposed along the drill collar.

DETAILED DESCRIPTION OF THE DISCLOSURE

30 [0011] Fig. 1 shows a schematic diagram of a drilling system 10 with a drillstring 20 carrying a drilling assembly 90 (also referred to as the bottom-hole assembly, or "BHA") conveyed in a "wellbore" or "borehole" 26 for drilling the wellbore. The drilling system 10 includes a conventional derrick 11 erected on a floor 12 which

supports a rotary table **14** that is rotated by a prime mover such as an electric motor (not shown) at a desired rotational speed. The drillstring **20** includes a tubing such as a drill pipe **22** or a coiled-tubing extending downward from the surface into the borehole **26**. The drillstring **20** is pushed into the wellbore **26** when a drill pipe **22** is
5 used as the tubing. For coiled-tubing applications, a tubing injector, such as an injector (not shown), however, is used to move the tubing from a source thereof, such as a reel (not shown), to the wellbore **26**. The drill bit **50** attached to the end of the drillstring breaks up the geological formations when it is rotated to drill the borehole **26**. If a drill pipe **22** is used, the drillstring **20** is coupled to a drawworks **30** via a
10 Kelly joint **21**, swivel **28**, and line **29** through a pulley **23**. During drilling operations, the drawworks **30** is operated to control the weight on bit, which is an important parameter that affects the rate of penetration. The operation of the drawworks is well known in the art and is thus not described in detail herein.

15 **[0012]** During drilling operations, a suitable drilling fluid **31** from a mud pit (source) **32** is circulated under pressure through a channel in the drillstring **20** by a mud pump **34**. The drilling fluid passes from the mud pump **34** into the drillstring **20** via a desurger (not shown), fluid line **38** and Kelly joint **21**. The drilling fluid **31** is discharged at the borehole bottom **51** through an opening in the drill bit **50**. The
20 drilling fluid **31** circulates uphole through the annular space **27** between the drillstring **20** and the borehole **26** and returns to the mud pit **32** via a return line **35**. The drilling fluid acts to lubricate the drill bit **50** and to carry borehole cutting or chips away from the drill bit **50**. A sensor **S₁** typically placed in the line **38** provides information about the fluid flow rate. A surface torque sensor **S₂** and a sensor **S₃** associated with the
25 drillstring **20** respectively provide information about the torque and rotational speed of the drillstring. Additionally, a sensor (not shown) associated with line **29** is used to provide the hook load of the drillstring **20**.

[0013] In one embodiment of the disclosure, the drill bit **50** is rotated by only rotating
30 the drill pipe **22**. In another embodiment of the disclosure, a downhole motor **55** (mud motor) is disposed in the drilling assembly **90** to rotate the drill bit **50** and the drill pipe **22** is rotated usually to supplement the rotational power, if required, and to effect changes in the drilling direction.

[0014] In an exemplary embodiment of **Fig. 1**, the mud motor **55** is coupled to the drill bit **50** via a drive shaft (not shown) disposed in a bearing assembly **57**. The mud motor rotates the drill bit **50** when the drilling fluid **31** passes through the mud motor **55** under pressure. The bearing assembly **57** supports the radial and axial forces of the drill bit. A stabilizer **58** coupled to the bearing assembly **57** acts as a centralizer for the lowermost portion of the mud motor assembly.

[0015] In one embodiment of the disclosure, a drilling sensor module **59** is placed near the drill bit **50**. The drilling sensor module contains sensors, circuitry and processing software and algorithms relating to the dynamic drilling parameters. Such parameters typically include bit bounce, stick-slip of the drilling assembly, backward rotation, torque, shocks, borehole and annulus pressure, acceleration measurements and other measurements of the drill bit condition. A suitable telemetry or communication sub **72** using, for example, two-way telemetry, is also provided as illustrated in the drilling assembly **90**. The drilling sensor module processes the sensor information and transmits it to the surface control unit **40** via the telemetry system **72**.

[0016] The communication sub **72**, a power unit **78** and an MWD tool **79** are all connected in tandem with the drillstring **20**. Flex subs, for example, are used in connecting the MWD tool **79** in the drilling assembly **90**. Such subs and tools form the bottom hole drilling assembly **90** between the drillstring **20** and the drill bit **50**. The drilling assembly **90** makes various measurements including the pulsed nuclear magnetic resonance measurements while the borehole **26** is being drilled. The communication sub **72** obtains the signals and measurements and transfers the signals, using two-way telemetry, for example, to be processed on the surface. Alternatively, the signals can be processed using a downhole processor in the drilling assembly **90**.

[0017] The surface control unit or processor **40** also receives signals from other downhole sensors and devices and signals from sensors **S₁-S₃** and other sensors used in the system **10** and processes such signals according to programmed instructions provided to the surface control unit **40**. The surface control unit **40** displays desired drilling parameters and other information on a display/monitor **42** utilized by an operator to control the drilling operations. The surface control unit **40** typically

includes a computer or a microprocessor-based processing system, memory for storing programs or models and data, a recorder for recording data, and other peripherals. The control unit **40** is typically adapted to activate alarms **44** when certain unsafe or undesirable operating conditions occur.

5

[0018] Turning now to **Fig. 2**, a cross-section of an acoustic sub that can be used for determining the formation density is illustrated. The drill collar is denoted by **103** and the borehole wall by **101**. An acoustic transducer assembly **107** is positioned inside the drill collar.

10

[0019] As shown in **Fig. 3**, the acoustic transducer assembly includes an fluid-filled cavity **109**. An acoustic transducer **111** such as a piezoelectric transducer is positioned at one side of the cavity **109**. On the other side of the cavity **109** is a sensor plate **115**. The cavity is filled with a fluid with known density and compressional wave velocity. The plate **115** has a known thickness, compressional

15

[0020] As shown in **Fig. 3**, activation of the transducer generates acoustic waves in the fluid. Exemplary raypaths resulting from the excitation are shown in **Fig. 3**. The ray path **117**, for example, corresponds to an acoustic wave that is reflected from the inner wall of the sensor plate. The raypath **121** corresponds to an acoustic wave that is reflected from the outer surface of the sensor plate while raypath **119** corresponds to a wave that passes into the borehole fluid in the annulus between the BHA and the borehole wall. The transducer **111** is provided with an absorptive backing **113** with an impedance that closely matches that of the transducer so as to reduce reflections from the back side of the transducer. In the example shown, a single transducer acts as both a transmitter and as a receiver, though this is not to be construed as limitation to the disclosure: separate acoustic transmitters and receivers may be used.

25

[0021] The present disclosure relies on the signals recorded by excitation of the transducer as an indication of gas in the borehole fluid. Free gas in the borehole fluid has three main effects on the acoustic properties of the fluid. The first effect is a reduction in density of the fluid. A more important effect is the dramatic reduction in the bulk modulus of the fluid (and hence the acoustic velocity). This is the

30

phenomenon that is the basis for the so-called “bright spot” effect in hydrocarbon exploration wherein the presence of gas in a reservoir can produce strong reflections on seismic data. Basically, in a gas-liquid mixture, the average compressibility (the reciprocal of bulk modulus which is linearly related to the square of the acoustic velocity) is obtained by a weighted average of the compressibilities of the two fluids. The third effect that may be observed is the attenuation of the wave that actually propagates into the borehole and may be reflected by the borehole wall. However, by the time actual gas bubbles appear in the borehole at depth, it may be on the verge of a blowout. Accordingly, an objective of the disclosure is to determine the pressure kicks before gas comes out of solution in the borehole fluid.

[0022] Invasion of formation fluids into the borehole is usually the result of the formation pore pressure exceeding the fluid pressure in the borehole. This may be a harbinger of a blowout and remedial action is necessary. Due to the difference in the density and P-wave velocity of the borehole mud and the density and P-wave velocity of formation fluid, this influx is detectable. Specifically, the effect of invasion is to lower the bulk modulus and density of the fluid in the borehole. This translates into a change in the impedance of the mud.

[0023] Fig. 5 shows an example of a cross-plot of modeled bulk modulus versus density for a three phase mixture. The example is from *Bulloch* (Michigan Technological University M.S. Thesis) using a model proposed by *Batzle* et al. The curve 191 is for an oil-water mixture for different fluid saturations, the curve 193 is for a three phase mixture of oil, water and gas, and the curve 195 is for a gas-water mixture. For the present disclosure, the model of *Batzle* et al. may be used with appropriate parameters for drilling fluid, live oil (oil with dissolved gas) and dead oil. This is not to be construed as a limitation of the present disclosure and other models for predicting the elastic properties of fluid mixtures may be used. *Han & Batzle* shows correlations of velocity and density to API gravity, Gas-Oil Ratio (GOR), Gas gravity and *in situ* pressure and temperatures. This is an example of another model that may be used with the method of the present disclosure. In practice, the empirical cross-plots may be stored in the form of a table and a table lookup performed to determine the presence of gas in the borehole fluid.

[0024] Such a model may also be used for predicting the properties of a mixture of drilling mud and formation fluid. The net result of a fluid influx is to change the impedance of the borehole fluid.

5 [0025] Those versed in the art and having benefit of the present disclosure would recognize that if the impedance of the fluid is matched to that of the plate, then reverberations of the plate caused by excitation of the transducer will decay very rapidly. This is shown schematically in **Fig. 4a** by the decay curve **153** of the reverberatory signal **151**. If, on the other hand, the impedance of the fluid is greatly
10 different from that of the plate, the reverberations **161** die out more slowly **163**. The relative decay can be quantified by the Q (or quality factor) of the plate. This is something that can be readily measured using prior art techniques.

[0026] Maximum sensitivity is obtained by using a plate whose acoustic impedance
15 is as close as possible to the fluid impedance so as to minimize the impedance contrast with the fluid, which typically ranges from 1500 kRayls for a light drilling fluid to 2300 kRayls for a heavy drilling fluid. The plate must also be thermally stable, mechanically tough, and chemically resistant. Among polymers, a polyimide ranging from 2400 to 2920 kRayls or a poly(etherether-ketone) ranging from 3122 to
20 3514 kRayls are good candidates. Another polymer that is a good candidate is polymethylpentene (tradenamed TPX, which is made by Mitsui) that has an acoustic impedance of 1840 kRayls. Pyrolytic graphite (6 480 kRayls depending on orientation) from GE Advanced Ceramics is a good candidate. Among metals, titanium (about 24 000 kRayls) or aluminum (about 15 800 kRayls) are good
25 candidates. The inside face of the plate is in contact with oil in a pressure-balanced enclosure, with known acoustic characteristics. Incoming water oil or gas is expected to lower the acoustic impedance markedly. The instrument takes a reading every second and stores it in memory for 2 hours. In one embodiment of the disclosure, if the instrument observes a change in acoustic impedance of 10% or more during a 2
30 minute interval from the extrapolated value of the preceding hour then it sends a high priority alarm and a series of informative values of the acoustic impedance from say intervals of 20 seconds preceding the alarm. The use of a 10% change in acoustic impedance is for exemplary purposes only and other criteria could be used for sending an alarm.

[0027] Another embodiment of the disclosure is illustrated in **Fig. 6**. Here, the BHA 205 is provided with a transducer arrangement **209** of the type discussed above and additional transducer assemblies **211, 213, 215, 217, 219** are disposed along the drill collar **221**. These are in electrical communication with each other and with a processor at the surface using wired-pipe telemetry (though other telemetry methods may be used). The impedance of the mud is estimated by determining the Q of the resonant plate. The velocity of P-waves in the mud may be measured using, for example, the apparatus described in US Patent Application Ser. No. 10/298706 of Hassan et al., having the same assignee as the present disclosure and the contents of which are incorporated herein by reference. Once the impedance and velocity are known, the density can be determined. The density may be a better indication of a potential gas kick than impedance or velocity separately.

[0028] The processing of the data may be accomplished by a downhole processor. Alternatively, measurements may be stored on a suitable memory device and processed upon retrieval of the memory device for detailed analysis. Implicit in the control and processing of the data is the use of a computer program on a suitable machine readable medium that enables the processor to perform the control and processing. The machine readable medium may include ROMs, EPROMs, EAROMs, Flash Memories and Optical disks. All of these media have the capability of storing the data acquired by the logging tool and of storing the instructions for processing the data. It would be apparent to those versed in the art that due to the amount of data being acquired and processed, it is impossible to do the processing and analysis without use of an electronic processor or computer.

[0029] While the foregoing disclosure is directed to the specific embodiments of the disclosure, various modifications will be apparent to those skilled in the art. It is intended that all such variations within the scope of the appended claims be embraced by the foregoing disclosure.

CLAIMS

What is claimed is:

- 1 1. An apparatus for detection of gas influx in a borehole fluid during drilling
2 operations, the apparatus comprising:
3 (a) a bottomhole assembly (BHA) configured to be conveyed in the
4 borehole;
5 (b) at least one transducer assembly on the BHA including:
6 (A) a sensor plate in contact with the borehole fluid, and
7 (B) a cavity disposed between a transducer and the sensor plate, the
8 transducer configured to generate acoustic vibrations in the
9 sensor plate; and
10 (c) a processor configured:
11 (C) to estimate from a signal indicative of the acoustic vibrations
12 an impedance of the borehole fluid, and
13 (D) to use the estimated fluid impedance to provide an indication of
14 the gas influx.
15
- 1 2. The apparatus of claim 1 wherein the cavity includes a fluid having a known
2 density and compressional velocity.
3
- 1 3. The apparatus of claim 1 wherein the signal indicative of the acoustic
2 vibrations is provided by at least one of: (i) the transducer, and (ii) a receiver.
3
- 1 4. The apparatus of claim 1 wherein the sensor plate has an acoustic impedance
2 selected to match an expected impedance of the borehole fluid.
3
- 1 5. The apparatus of claim 1 wherein the processor is configured to estimate the
2 impedance of the borehole fluid by determining a quality factor (Q) of the
3 acoustic vibrations.
4
- 1 6. The apparatus of claim 1 wherein the processor is configured to provide the
2 indication of gas influx using a table lookup.
3

- 1 7. The apparatus of claim 1 further comprising a device configured to measure a
2 P-wave velocity in the borehole fluid and wherein the processor is configured
3 to provide the indication of gas influx using a density derived from the
4 estimated fluid impedance and the measured P-wave velocity.
5
- 1 8. The apparatus of claim 1 wherein the sensor plate is made of a material
2 selected from: (i) a polyamide, (ii) a polymethylpentene, (iii) pyrolitic
3 graphite, (iv) titanium, and (v) aluminum.
4
- 1 9. The apparatus of claim 1 further comprising an absorptive backing on a back
2 side of the transducer having an impedance substantially equal to that of the
3 transducer.
4
- 1 10. The apparatus of claim 1 wherein the at least one transducer assembly further
2 comprises a plurality of transducer assemblies in electrical communication.
3
- 1 11. The apparatus of claim 1 wherein the transducer is configured to provide the
2 indication of gas influx by providing an alarm signal when the estimated fluid
3 impedance changes by more than a specified threshold value relative to the
4 estimated fluid impedance in an earlier interval.
5
- 1 12. A method of detecting gas influx in a borehole fluid during drilling
2 operations, the method comprising:
3 (a) conveying a bottomhole assembly (BHA) including at least one
4 transducer assembly into the borehole;
5 (b) using a transducer on a first side of a cavity in the transducer assembly
6 to generate acoustic vibrations in a sensor plate on a second side of the
7 cavity, the sensor plate being in contact with the borehole fluid;
8 (c) estimating from a signal indicative of the acoustic vibrations an
9 impedance of the borehole fluid, and
10 (d) using the estimated fluid impedance to provide an indication of the gas
11 influx.
12

- 1 13. The method of claim 12 further comprising having a fluid having with a
2 known density and a known compressional velocity in the cavity.
3
- 1 14. The method of claim 12 further comprising providing the signal indicative of
2 the acoustic vibrations using at least one of: (i) the transducer, and (ii) a
3 receiver.
4
- 1 15. The method of claim 12 further comprising selecting a material for the sensor
2 plate that has an acoustic impedance which matches an expected impedance of
3 the borehole fluid.
4
- 1 16. The method of claim 12 wherein estimating the impedance of the borehole
2 fluid further comprises determining a quality factor (Q) of the acoustic
3 vibrations.
4
- 1 17. The method of claim 12 wherein the providing the indication of gas influx
2 further comprises using a table lookup.
3
- 1 18. The method of claim 12 further comprising measuring a P-wave velocity in
2 the borehole fluid and wherein the providing the indication of gas influx
3 further comprises using a density derived from the estimated fluid impedance
4 and the measured P-wave velocity.
5
- 1 19. The method of claim 12 further comprising selecting a material for the sensor
2 plate from: (i) a polyamide, (ii) a polymethylpentene, (iii) pyrolitic graphite,
3 (iv) titanium, and (v) aluminum.
4
- 1 20. The method of claim 12 further comprising providing an absorptive backing
2 on a back side of the transducer to reduce reflections therefrom
3
- 1 21. The method of claim 12 further comprising using, for the at least one
2 transducer assembly, a plurality of transducer assemblies in electrical
3 communication.
4

- 1 22. The method of claim 12 wherein providing the indication of gas influx further
2 comprises providing an alarm signal when the estimated fluid impedance
3 changes by more than a specified threshold value relative to the estimated
4 fluid impedance in an earlier interval.
5
- 1 23. A computer readable medium for use with an apparatus for detection of gas
2 influx in a borehole fluid during drilling operations, the apparatus comprising:
3 (a) a bottomhole assembly (BHA) configured to be conveyed in the
4 borehole;
5 (b) at least one transducer assembly on the BHA including:
6 (A) a sensor plate in contact with the borehole fluid, and
7 (B) a cavity disposed between a transducer and the sensor plate, the
8 transducer configured to generate acoustic vibrations in the
9 sensor plate;
10 the medium comprising instructions that enable a processor to:
11 (c) estimate from a signal indicative of the acoustic vibrations an
12 impedance of the borehole fluid, and
13 (d) use the estimated fluid impedance to provide an indication of the gas
14 influx.
15
- 1 24. The computer readable medium of claim 23 further comprising at least one of:
2 (i) a ROM, (ii) an EPROM, (iii) an EAROM, (iv) a flash memory, and (v) an
3 optical disk.
4

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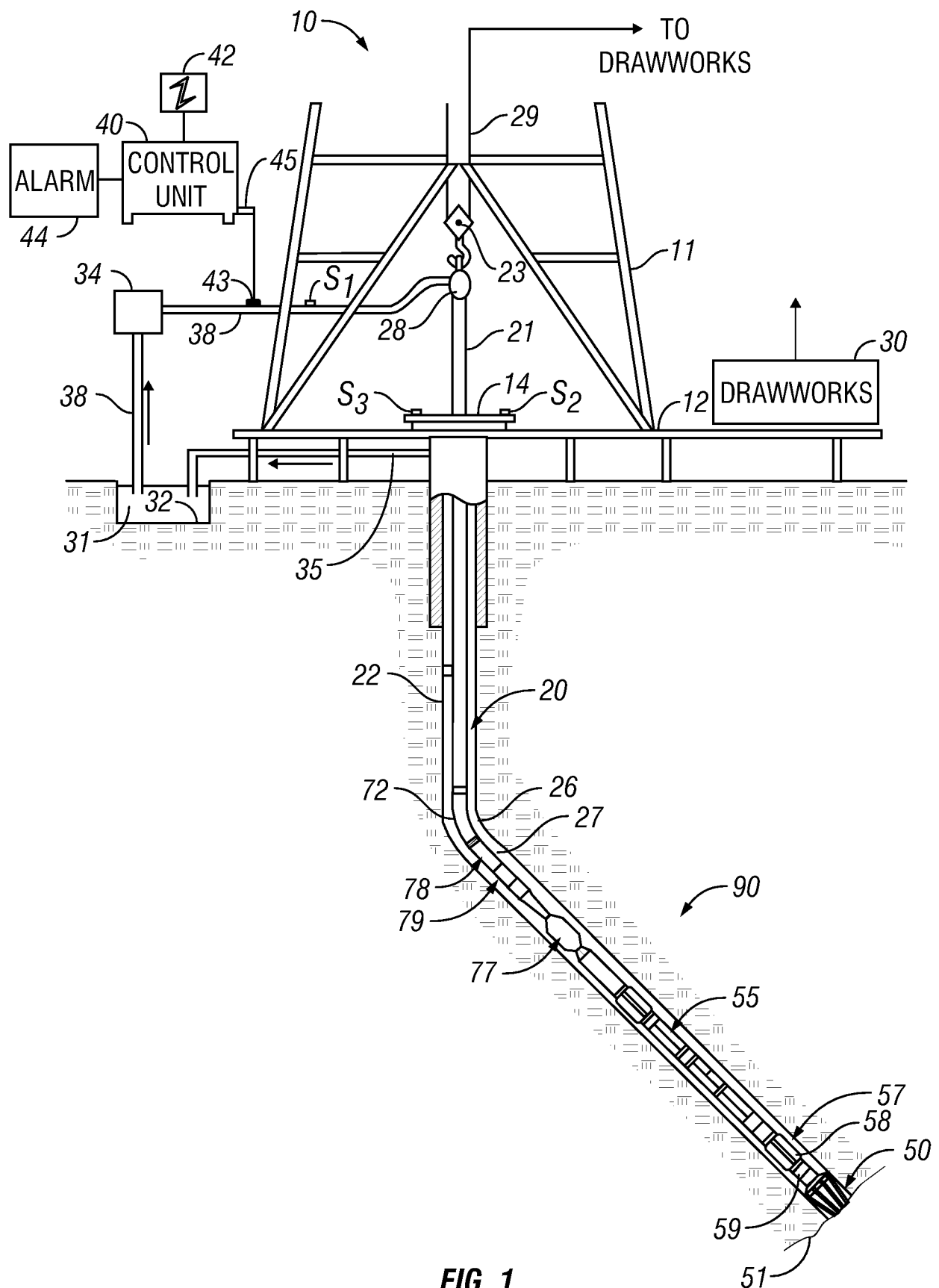


FIG. 1
(Prior Art)

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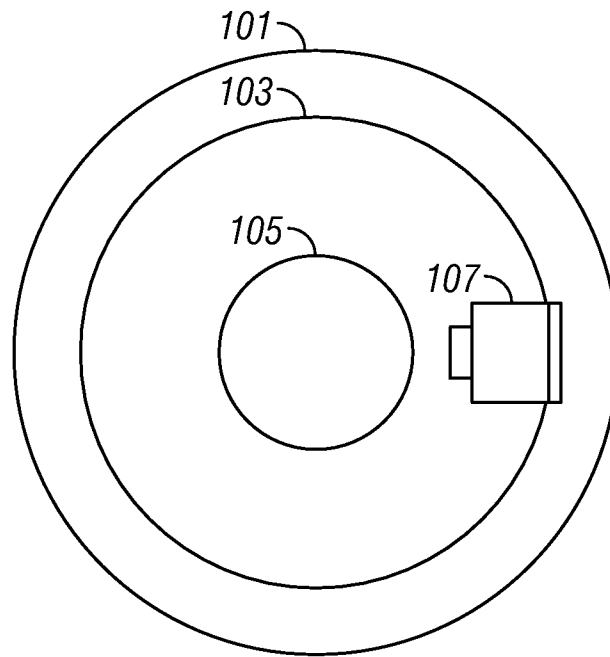


FIG. 2

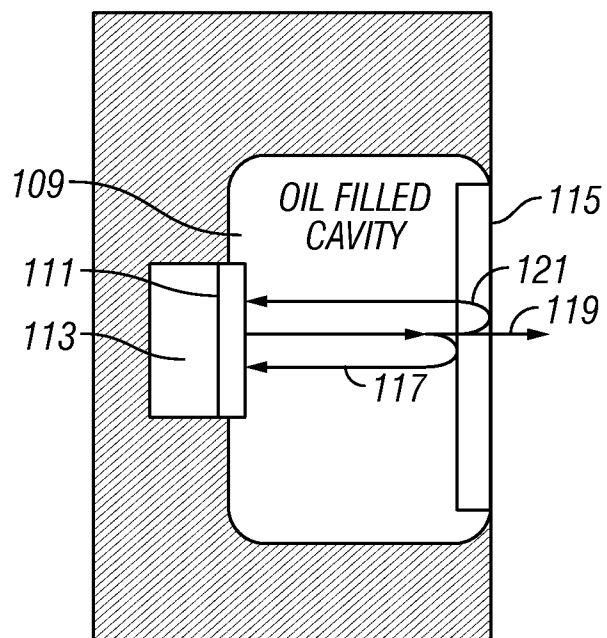


FIG. 3

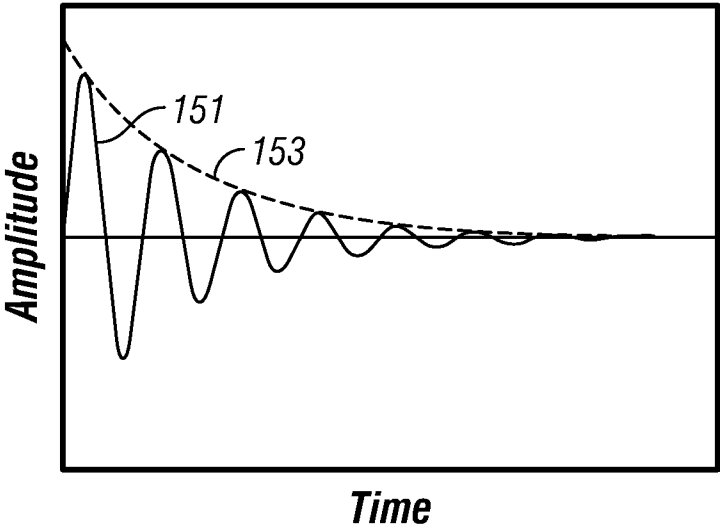


FIG. 4A

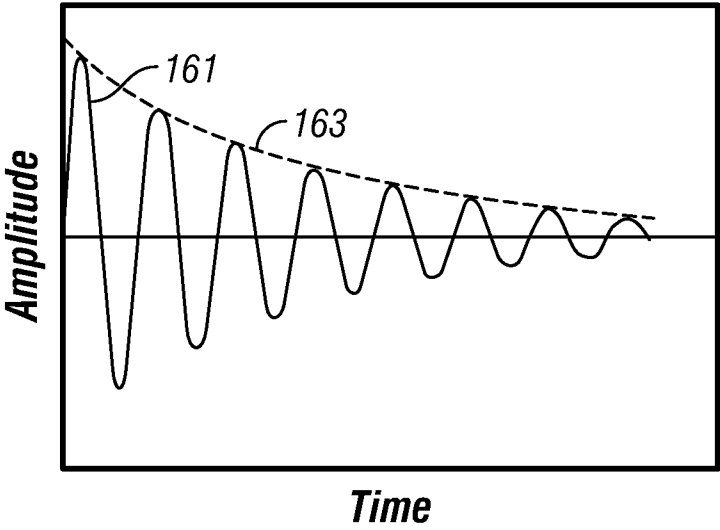


FIG. 4B

4/5

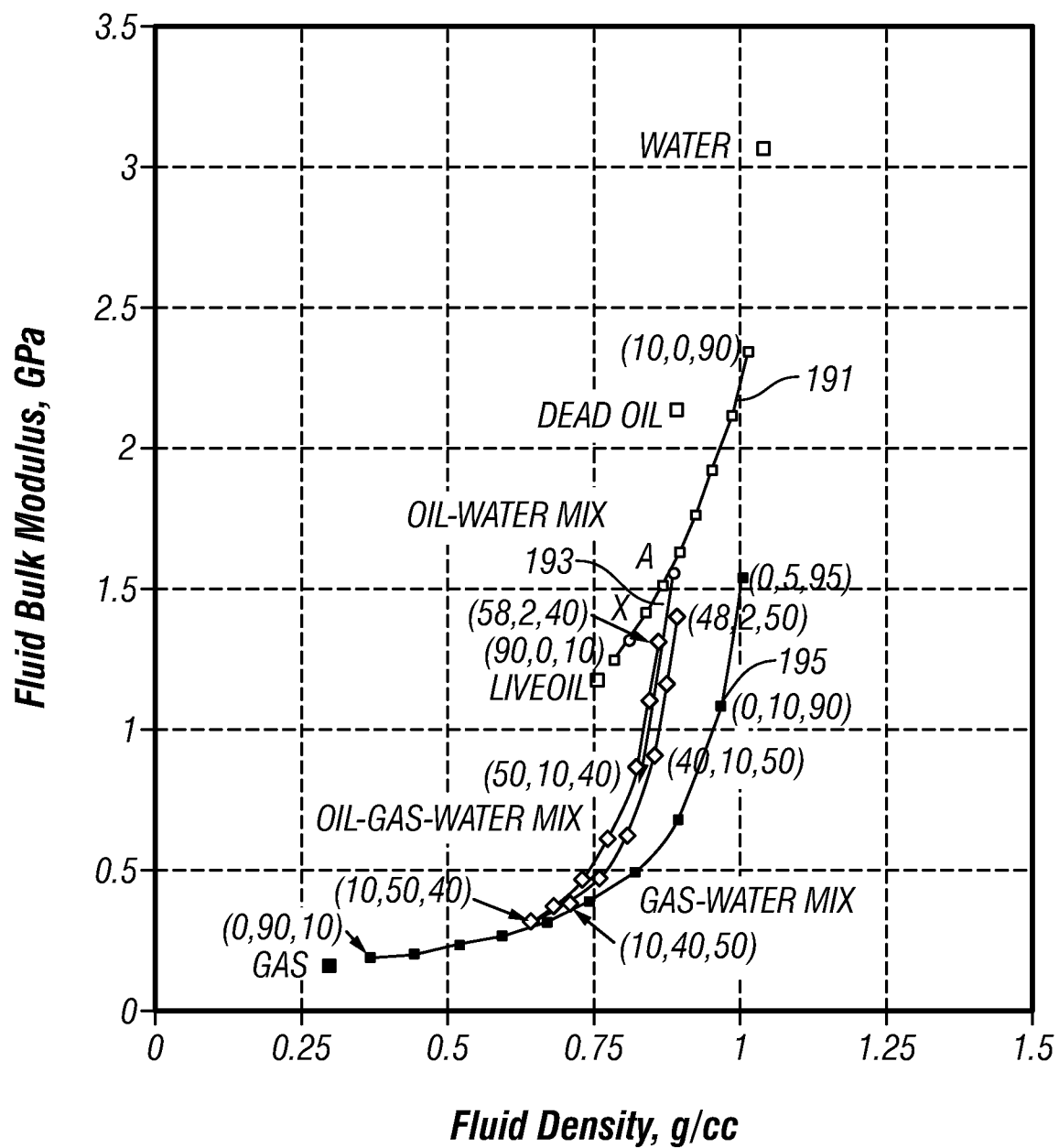


FIG. 5
(Prior Art)

5/5

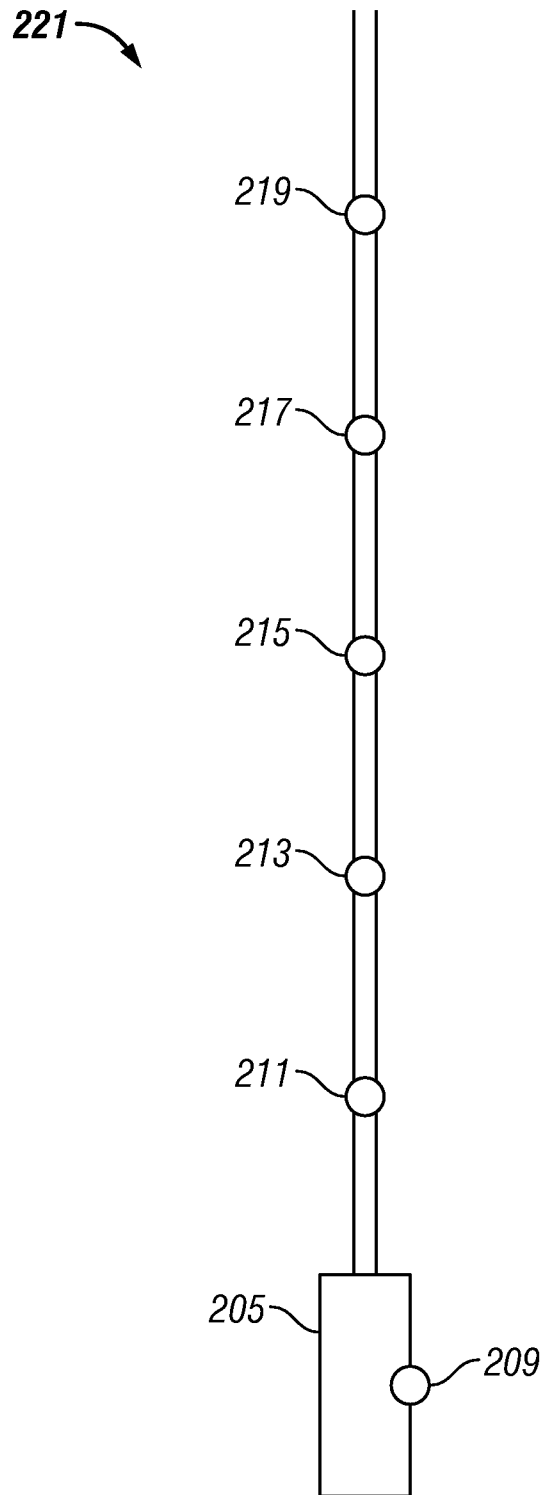


FIG. 6