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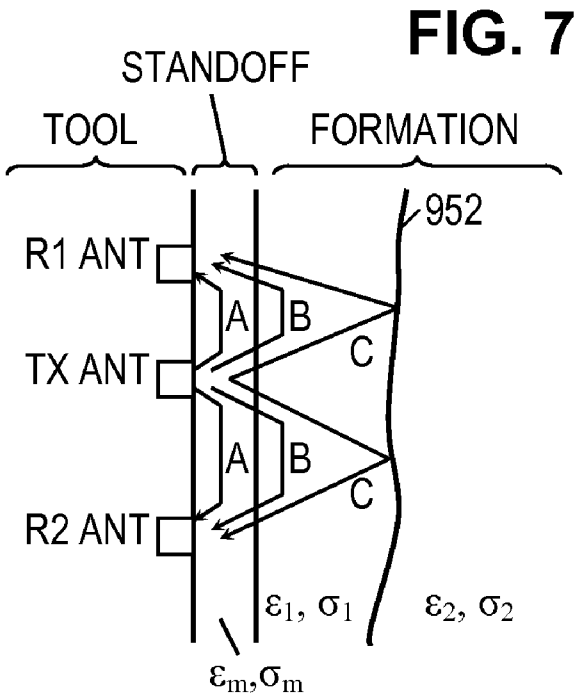
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(54) **Title**: A 3D BOREHOLE IMAGER



(57) **Abstract**: Logging tools and methods for obtaining a three-dimensional (3D) image of the region around a borehole. In at least some embodiments, a 3D imaging tool rotates, transmitting pulses that are approximately a nanosecond long and measuring the time it takes to receive reflections of these pulses. Multiple receivers are employed to provide accurate triangulation of the reflectors. In some cases, multiple transmitters are employed to obtain compensated measurements, i.e., measurements that compensate for variations in the receiver electronics. Because reflections occur at boundaries between materials having different dielectric constants, the 3D imaging tool can map out such boundaries in the neighborhood of the borehole. Such boundaries can include: the borehole wall itself, boundaries between different formation materials, faults or other discontinuities in a formation, and boundaries between fluids in a formation. Depending on various factors, the size of the borehole neighborhood mapped out can be as large as 1 meter.

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A 3D Borehole Imager

CROSS-REFERENCE TO RELATED APPLICATIONS

This application claims priority to Provisional U.S. Pat. App. 61/117,433, filed Nov. 24, 2008 by inventors Michael S. Bittar, Jing Li and Stephen A. Zannoni, which is hereby incorporated herein by reference.

BACKGROUND

Oil field operators seek as much information as possible regarding parameters and conditions encountered downhole. Such information typically includes characteristics of the earth formations traversed by the borehole, and data relating to the size and configuration of the borehole itself. The collection of information relating to conditions downhole, which commonly is referred to as "logging," can be performed by several methods including wireline logging, "logging while drilling" (LWD), drillpipe conveyed logging, and coil tubing conveyed logging.

In wireline logging, a probe or "sonde" is lowered into the borehole after some or all of the well has been drilled. The sonde hangs at the end of a long cable or "wireline" that provides mechanical support to the sonde and also provides an electrical connection between the sonde and electrical equipment located at the surface of the well. In accordance with existing logging techniques, various parameters of the earth's formations are measured and correlated with the position of the sonde in the borehole as the sonde is pulled uphole.

In LWD, the drilling assembly includes sensing instruments that measure various parameters as the formation is being penetrated. While LWD techniques allow more contemporaneous formation measurements, drilling operations create an environment that is generally hostile to electronic instrumentation and sensor operations.

In drillpipe- or coil tubing-conveyed logging, sensing instruments are mounted on a tubing string, which moves the instrument package through an existing borehole. The tubing string enables logging of horizontal well bores without requiring the sensing instruments to tolerate the hostile drilling environment. Typically, the measurement data is stored in internal memory and recovered along with the instrument package.

Most logging tools acquire a single depth-dependent measurement, enabling a driller to see the measurement of temperature, pressure, density, resistivity, natural gamma radiation,

borehole diameter, etc., as a function of depth. A few existing logging tools offer measurements as a function of depth and rotational angle, enabling a driller to see, e.g., an image of the borehole wall. A very few existing logging tools offer measurements as a function of depth and radial distance from the borehole (e.g., induction tools having multiple depths of investigation). While each of these tools is useful to some degree, they leave the driller with an incomplete picture of the situation downhole.

BRIEF DESCRIPTION OF THE DRAWINGS

A better understanding of the various disclosed embodiments can be obtained when the following detailed description is considered in conjunction with the attached drawings, in which:

Fig. 1 shows an illustrative logging while drilling (LWD) environment;

Fig. 2 shows an illustrative wireline logging environment;

Fig. 3 shows an illustrative LWD tool having a first antenna arrangement suitable for 3D imaging;

Fig. 4 shows an illustrative LWD tool having a second antenna arrangement suitable for 3D imaging;

Fig. 5A shows an illustrative broadband horn antenna;

Fig. 5B shows a resistively loaded bowtie antenna;

Fig. 6 is a block diagram of illustrative tool electronics;

Fig. 7 shows illustrative 3D image measurement contributions;

Fig. 8 shows an illustrative transmit pulse;

Fig. 9 shows an illustrative receive signal; and

Fig. 10 shows an illustrative 3D image.

While the invention is susceptible to various modifications and alternative forms, specific embodiments thereof are shown by way of example in the drawings and will herein be described in detail. It should be understood, however, that the drawings and detailed description thereto are not intended to limit the disclosure, but on the contrary, the intention is to cover all modifications, equivalents and alternatives falling within the scope of the appended claims.

DETAILED DESCRIPTION

The problem identified in the background is at least partly addressed by the logging tools and methods disclosed herein for obtaining a three-dimensional (3D) image of the region around a borehole. In at least some embodiments, a 3D imaging tool rotates, transmitting pulses that are approximately a nanosecond long and measuring the time it takes to receive reflections of these pulses. Multiple receivers are employed to provide accurate triangulation of the reflectors. In some cases, multiple transmitters are employed to obtain compensated measurements, i.e., measurements that compensate for variations in the receiver electronics. Because reflections occur at boundaries between materials having different dielectric constants, the 3D imaging tool can map out such boundaries in the neighborhood of the borehole. Such boundaries can include: the borehole wall itself, boundaries between different formation materials, faults or other discontinuities in a formation, and boundaries between fluids in a formation. Depending on various factors, the size of the borehole neighborhood mapped out by this 3D imaging tool can be as large as 1 meter.

The disclosed logging tools and methods are best understood in the context of the larger systems in which they operate. Accordingly, Fig. 1 shows an illustrative logging-while-drilling ("LWD") environment. A drilling platform 2 supports a derrick 4 having a traveling block 6 for raising and lowering a drill string 8. A top drive 10 supports and rotates the drill string 8 as it is lowered through the wellhead 12. A drill bit 14 is driven by a downhole motor and/or rotation of the drill string 8. As bit 14 rotates, it creates a borehole 16 that passes through various formations. A pump 18 circulates drilling fluid 20 through a feed pipe 22, through the interior of the drill string 8 to drill bit 14. The fluid exits through orifices in the drill bit 14 and flows upward through the annulus around the drill string 8 to transport drill cuttings to the surface, where the fluid is filtered and recirculated.

The drill bit 14 is just one piece of a bottom-hole assembly that includes one or more drill collars (thick-walled steel pipe) to provide rigidity and add weight to aid the drilling process. Some of these drill collars include built-in logging instruments to gather measurements of various drilling parameters such as position, orientation, weight-on-bit, borehole diameter, etc. The tool orientation may be specified in terms of a tool face angle (rotational orientation), an inclination angle (the slope), and compass direction, each of which can be derived from measurements by magnetometers, inclinometers, and/or accelerometers, though other sensor

types such as gyroscopes may alternatively be used. In one specific embodiment, the tool includes a 3-axis fluxgate magnetometer and a 3-axis accelerometer. As is known in the art, the combination of those two sensor systems enables the measurement of the tool face angle, inclination angle, and compass direction. Such orientation measurements can be combined with gyroscopic or inertial measurements to accurately track tool position.

A LWD 3D imaging tool 24 can be included in the bottom-hole assembly near the bit 14. As the bit extends the borehole through the formations, 3D imaging tool 26 rotates and collects azimuthally-dependent reflection measurements that a downhole controller associates with tool position and orientation measurements to form a 3D image map of the borehole neighborhood. The measurements can be stored in internal memory and/or communicated to the surface. A telemetry sub 26 may be included in the bottom-hole assembly to maintain a communications link with the surface. Mud pulse telemetry is one common telemetry technique for transferring tool measurements to surface receivers and receiving commands from the surface, but other telemetry techniques can also be used.

At the surface, a data acquisition module 36 receives the uplink signal from the telemetry sub 26. Module 36 optionally provides some preliminary processing and digitizes the signal. A data processing system 50 (shown in Fig. 1 as a computer) receives a digital telemetry signal, demodulates the signal, and displays the tool data or well logs to a user. Software (represented in Fig. 1 as information storage media 52) governs the operation of system 50. A user interacts with system 50 and its software 52 via one or more input devices 54 and one or more output devices 56.

At various times during the drilling process, the drill string 8 may be removed from the borehole as indicated in Fig. 2. Once the drill string has been removed, logging operations can be conducted using a wireline logging tool 34, i.e., a sensing instrument sonde suspended by a cable 42 having conductors for transporting power to the tool and telemetry from the tool to the surface. A dielectric logging portion of the logging tool 34 may have sensing pads 36 that slide along the borehole wall as the tool is pulled uphole. A logging facility 44 collects measurements from the logging tool 34, and includes computing facilities for processing and storing the measurements gathered by the logging tool.

Fig. 3 shows a side view of an illustrative LWD tool 302 having a first antenna arrangement suitable for 3D imaging. The electronics behind faceplate 304 are coupled to a

transmitter 306 and two receivers 308, 310. Multiple receivers are provided to enable triangulation of the reflectors. In the embodiment of Fig. 3, the receivers are spaced at different distances and in different directions from the transmitter. In Fig. 4, an alternative LWD tool 402 has a second antenna arrangement suitable for 3D imaging. In the second antenna arrangement, three receivers 408, 410, and 412, are positioned in a row between two transmitters 404 and 406. This antenna arrangement enables compensated measurements to be made and improves measurement reliability because more information is available that can be used to correct for environmental effects. Moreover, the second antenna arrangement provides a degree of redundancy that enables the tool to continue operating even if one of the receivers and one of the transmitters fail.

As the LWD 3D imaging tools 302, 402, rotate and progress downhole at the drilling rate, each sensing surface will trace a helical path on the borehole wall. Orientation sensors within the tool can be used to associate the measurements with the sensors' positions on the borehole wall. Electronics within the tool can aggregate measurements versus position to form a detailed map (or 3D image) of the borehole wall, which can be stored for later retrieval or compressed and transmitted to the surface for timely use by the drilling team. If sufficient telemetry bandwidth is available, surface computing facilities can collect formation property measurements, orientation (azimuth) measurements, and tool position measurements, and process the collected measurements to create and display the map (or 3D image).

Though the antenna arrangements of Figs. 3 and 4 are shown on LWD tools, they can be employed in 3D imaging wireline tools. In a wireline tool, the antennas can be mounted on a rotating head to enable scanning in each direction. Alternatively, multiple azimuthally-spaced antennas can be employed to enable scanning in different directions without requiring antenna and/or tool rotation. In both the wireline and LWD 3D imaging tool embodiments, the antennas can take the form of ridged microwave horns such as that shown in Fig. 5A, or the form of resistively loaded bowtie antennas as shown in Fig. 5B. In the isometric scale drawing of Fig. 5A, the overall dimensions of the antenna horn 702 are about 2.5 cm high, 3.8 cm wide, and 4.0 cm deep, including the rectangular feed chamber 704. The antenna bandwidth is increased by the presence of two ridges 706 extending from the feed point to the aperture. A coaxial cable 708 is used to drive the antenna.

The interior of the horn 702 is filled with a dielectric material having a relative permittivity between 1 and 100. Depending on this permittivity value, the low frequency cutoff ranges from 15 GHz (relative permittivity=1) to 1GHz (relative permittivity=100), and the bandwidth is approximately 3 GHz. If the size of the antenna is increased, the low cutoff frequency can be reduced to 300 MHz or even lower. These wide bandwidths enable these ridged horn antennas to efficiently transmit and receive short electromagnetic pulses.

The bowtie antenna shown in Fig. 5B has two conductive elements 722 mounted on a pad of microwave-absorbing material 724. The conductive elements have a generally triangular shape with an opening angle γ of about 60°. The combined length of the conductive elements, L, is greater than or equal to half of the pulse span in space. Thus, for example, a tool operating with a pulse width of $1x10^{-9}$ s in an environment where the speed of light c is $2.8x10^{8}$ m/s would have an overall length L greater than or equal to about 14 cm. The microwave-absorbing material provides resistive loading to broaden the bandwidth of the antenna, and it further acts to reduce the influence of the conductive tool body on the performance of the antenna. The bowtie antenna structure can in many cases be easier to manufacture and install than the horn antenna.

Fig. 6 shows a block diagram of the electronics for an illustrative 3D imaging tool. The tool electronics include a system clock and control unit 902, multiple time delay lines 904, 906, 908, an electromagnetic pulse transmitter 912, two pulse wave receivers, a multichannel data acquisition unit 916, a data processing and storage unit 918, and the transmitting and receiving antennas discussed previously.

The clock and control unit 902 determines the sampling rate of the system. To do each measurement, unit 902 sends a trigger signal via the programmable delay lines 904-908 to the transmitter 912 and the receivers 910, 914. Upon the receiving of the trigger signal, the transmitter 912 generates a short electromagnetic pulse wave and emits it into space through the transmitting antenna. The trigger signal also causes the receivers start sampling the reflected signals with a dynamic gain, i.e., a gain that increases with time to at least partly compensate for signal attenuation. Since the transmitter and the receivers have different response speeds, the time delay lines are carefully adjusted to guarantee synchronization between the transmitter and the receivers. The receivers 910, 914 sample and output analog signals to the data acquisition unit 916, which converts the analog signals into digital signals. The processing and storage unit 918 processes the received digital signals to extract measurement information. The extracted

information can be stored and/or transmitted via the telemetry system to the surface for real-time monitoring.

Fig. 7 illustrates the operation of a time-domain electromagnetic (EM) tool that provides 3-D imaging of the borehole and the formation behind the borehole wall in the presence of non-conducting oil-based mud. The tool includes an array of EM short-pulse transmitters, time-synchronized receivers, and antennas. The antennas are mounted on the mandrel for LWD applications. The borehole and formation reflections are processed to find out the imaging and the eccentricity of the borehole and the formation near the borehole region, which results in a 3-D imaging of the borehole and the formation near the borehole.

Fig. 7 shows two receiver antennas placed at different spacings with respect to the transmitter antenna to provide enough measurement equations to solve parameters for multi-layer formations, and to enlarge the dynamic range of measurements. The drill collar is surrounded by oil-based mud having permittivity ε_m and conductivity σ_m. The standoff distance between the antennas and the borehole wall may vary with the tool-face angle in eccentric boreholes. Outside the borehole is formation 1 (having permittivity ε_1 and conductivity σ_1), and possibly a second formation 2 (having permittivity ε_2 and conductivity σ_2), and a third etc. In the case shown in Fig. 7, the signals received by receiver antenna 1 include 3 components: EM waves propagating through the oil-based mud (A), EM waves propagating through formation 1 (B), and the waves reflected from the boundary between formation 1 and formation 2 (C). Similarly, receiver antenna 2 also receives a signal having these three components.

Fig. 8 shows an approximately Gaussian pulse having a pulse width T of in the range between 0.3-2.0 nanoseconds. (Some tool embodiments may support pulse widths up to 100 ns.) Fig. 9 shows the simulated signal that is received in response to the transmission of the pulse in Fig. 8. In this simulation, the transmission of a pulse wave such as that shown in Fig. 8 results in the signal received by either receive antenna having the three wavelets shown in Fig. 9 (other formation configurations can produce a greater or lesser number of wavelets). Once the three wavelets are identified from the received signals, their magnitudes and time delays can be obtained and used to solve for various parameters including ε_m, σ_m, ε_1, σ_1, ε_2, and σ_2, and the distances to the borehole wall and the formation boundaries. Because the measurements are conducted while drilling, when the drill collar completes rotation of 360° at any depth P, the

azimuthal dependence of these parameters in the plane z = P can be obtained. Here the coordinate z takes the direction of the borehole axis. With the drill collar going forward, the three dimensional distribution of the formation parameters is determined, thereby yielding a 3D image of the formation.

We note here that the amplitude of the wavelet 1 shown in Fig. 9 is not only influenced by the resistivity of the drilling fluid, but also by the standoff distance of the borehole. In the eccentric cases, the amplitude of wavelet 1 can be expressed by the following function:

$$A_1 = a_0 + b_0 \sin(\varphi + \theta_0) \quad (1)$$

where θ_0 is an initial phase angle, φ is the tool-face angle, a_0 is the average amplitude in the plane z = P, and b_0 is determined by the eccentricity of the drilling collar. The larger the b_0, the more serious the eccentricity is.

Additional antennas can be used to make the measurements more reliable. The antenna arrangement of Fig. 4 exploits three receivers and two transmitters to increase the number of measurement equations. The two transmitters at the ends of the antenna array take turns transmitting EM pulses, and the signals from each of the three receivers are sampled in response to the transmitted pulses. The use of two transmitters at two ends enables the system to determine compensated measurements that cancel system heat noise and other system errors. The three receivers make measurements more reliable by providing more measurement equations and making it possible to image formations with more layers. The antenna arrangement of Fig. 4 also provides redundancy, enabling the system to continue operating even if one of the transmitters and one of the receivers break down. The disclosed tools offer a power savings in that the high-power transmit signals have extremely short durations and a low duty cycle, creating a low average power consumption.

For wireline applications, the operating principles are the same. The sensors can be mounted on a rotating head to provide full azimuthal scanning at each depth in the well. Alternatively, sensors can be mounted at different azimuthal orientations on the tool to provide "azimuthally sampled" coverage.

The data acquired by the 3D imaging tool can be presented in a number of forms, including a volumetric solid in cylindrical coordinates as shown in Fig. 10. The volume around the borehole is divided into a cylindrical grid 1002, with each of the cells in the grid having associated formation properties, which can be shown by color, transparency, texture, and/or

other visual characteristics. To determine these properties, the data acquisition system (e.g., computer 50 of Fig. 1) processes the measured amplitudes and time delays of the pulse reflections as a function of tool position and orientation, thereby mapping out surfaces representing changes in resistivity. These surfaces can be shown directly or they can be used to derive estimates of the formation properties in the regions delineated by the surfaces. As the image is displayed on a computer screen 56, the user can interact with it to gain a better understanding of the structures shown, e.g., by viewing different cross-sections, different orientations, adjusting the colors, etc.

Numerous applications exist for a 3D imaging tool. One example is measurement of invasion depth and invasion rate, i.e., the distance that drilling fluid has penetrated into the formation. Asymmetries in the invasion rates may be indicative of stress orientations and fracture orientations, and the invasion rate can provide a measure of formation fluid mobility. With the geometry of the invaded region having been accurately determined, accurate measurement of the invaded region's resistivity can be accurately performed, further simplifying the determination of bulk formation resistivity.

Another application example is the measurement of borehole caliper, shape, texture. Travel time inversion, combined with the measurement of drilling fluid properties with a so-called "mud cell", enables accurate determination of the borehole geometry and the eccentering of the tool. From the borehole geometry measurements, an accurate 3D model of the borehole can be constructed and displayed.

Another application example is the measurement of formation dip and dip azimuth. The tool can detect formation boundary distances and measure the variation of these distances as a function of tool face angle and tool position within the borehole. These measurements enable straightforward determination of the relative dip.

In some variations of the tool, the antennas are enlarged and spaced further apart to support the use of low frequency electromagnetic signal pulses. Such low frequency pulses enable deeper signal penetrations into the formation. Deeper investigation depths may be possible, possibly even ahead of the bit. Other applications for such tool variations include mapping of natural fractures in the formation and monitoring the growth of hydraulic fractures.

The processing of reflected signals need not be limited to simple time-of-flight measurements. The tool can analyze reflection amplitudes, shapes, and waveform coda (signals

indicative of multiple reflections or multiple scattering of the transmitted pulse) to determine formation properties, formation structural information, formation fluid properties, borehole fluid properties, borehole geometry, invasion zone geometry, and other petrophysical information that can be displayed in a 3D image either separately or combined.

Numerous variations and modifications will become apparent to those skilled in the art once the above disclosure is fully appreciated. It is intended that the following claims be interpreted to embrace all such variations and modifications.

CLAIMS

WHAT IS CLAIMED IS:

1. A borehole logging method that comprises:

conveying an imaging tool along a borehole and tracking a position of the tool;

transmitting an electromagnetic pulse from the imaging tool in each of multiple azimuthal directions;

detecting a receive signal in response to each electromagnetic pulse;

processing each receive signal to determine travel times of any reflections; and

forming a three-dimensional (3D) image of a formation around the borehole based at least in part on said travel times as a function of position and azimuthal direction.

2. The method of claim 1, further comprising:

recording the 3D image in an information storage medium; and

displaying the 3D image.

3. The method of claim 1, wherein said processing further determines amplitudes of said reflections.

4. The method of claim 3, further comprising finding an eccentricity of the tool based on azimuthal variation of first-reflection amplitudes.

5. The method of claim 1, further comprising detecting multiple receive signals in response to each electromagnetic pulse, each receive signal being measured by a respective receiver antenna.

6. The method of claim 5, wherein the receiver antennas are spaced at different distances from a transmitter antenna that transmits the electromagnetic pulses.

7. The method of claim 1, wherein said transmitting includes alternately driving two, axially-spaced transmitter antennas.

8. The method claim 1, wherein said transmitting is performed by driving at least one ridged horn antenna to generate a pulse having a width less than or equal to $2x10^{-9}$ seconds.

9. The method of claim 1, wherein said forming a 3D image further includes analyzing at least one of: reflection amplitudes, pulse shapes, and waveform coda.

10. A borehole logging tool for 3D imaging, the tool comprising:

a first transmitter antenna that transmits electromagnetic pulses;

a first and second receiver antennas spaced axially at different distances from the first transmitter antenna to receive reflections of the electromagnetic pulses; and

electronics that determine travel times from said reflections and associate said travel times with position and azimuth.

11. The tool of claim 10, further comprising:

a second transmitter antenna axially spaced from said first transmitter antenna, wherein the first and second transmitter antennas alternately transmit electromagnetic pulses.

12. The tool of claim 11, further comprising:

a third receiver antenna positioned midway between the first and second transmitter antennas.

13. The tool of claim 10, wherein each of the transmitter and receiver antennas is a ridged horn antenna having a bandwidth of at least 3 GHz.

14. The tool of claim 10, wherein said electromagnetic pulses have widths less than or equal to $2x10^{-9}$ s.

15. The tool of claim 10, wherein the electronics further determine amplitudes of said reflections as a function of position and azimuth and find an eccentricity value based on said amplitudes.

16. The tool of claim 10 and further comprising:

a data processing system that processes said travel times to form a 3D image of a formation around the borehole.

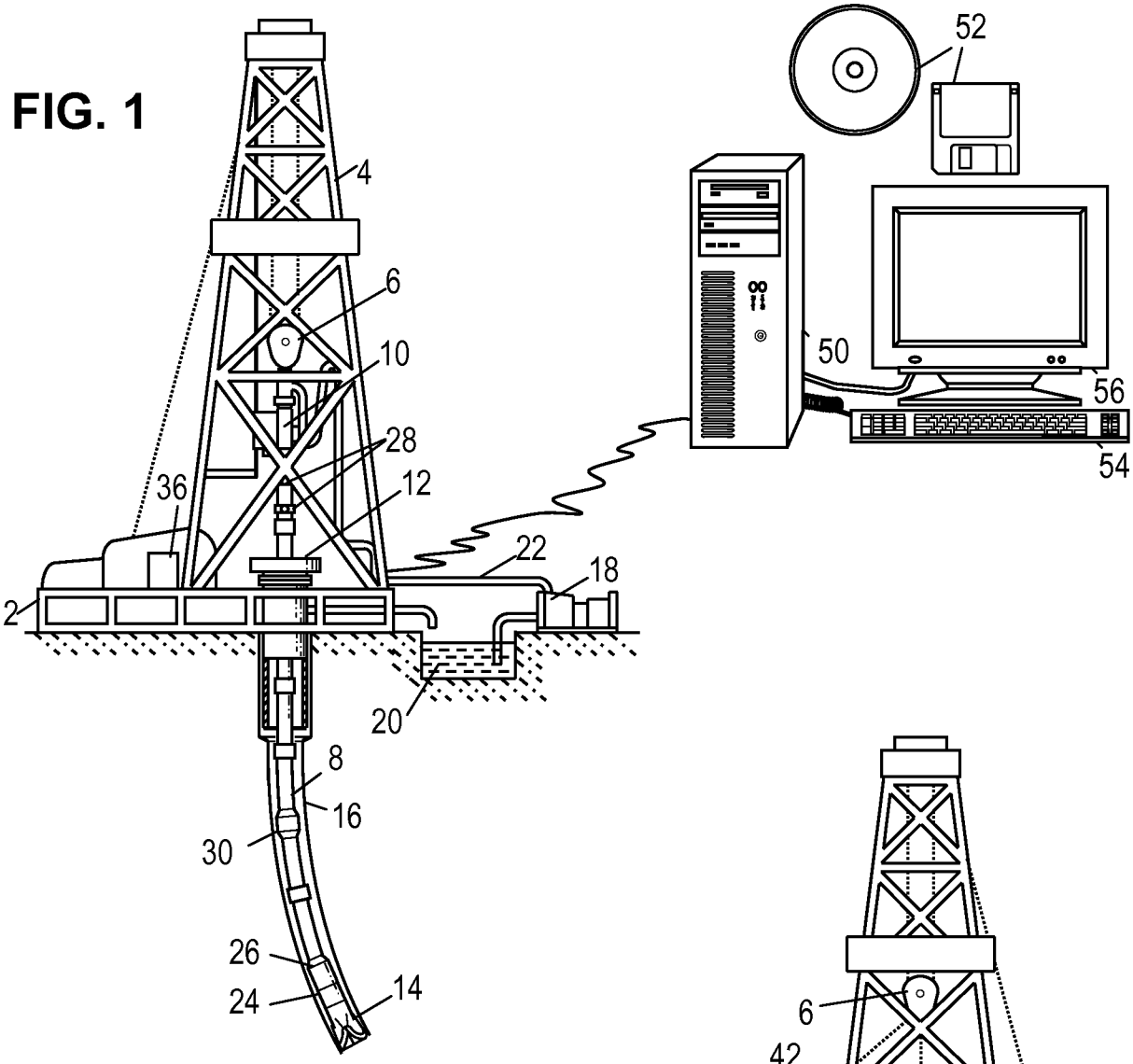
17. The tool of claim 16, wherein the data processing system displays the 3D image.

18. The tool of claim 16, wherein the data processing system stores the 3D image in an information storage medium.

19. The tool of claim 10, further comprising a drill collar that houses the transmitter and receiver antennas and the electronics, said drill collar suitable for inclusion in a bottomhole assembly of a drill string.

20. The tool of claim 10, further comprising a wireline sonde that houses the transmitter and receiver antennas and the electronics.

FIG. 1


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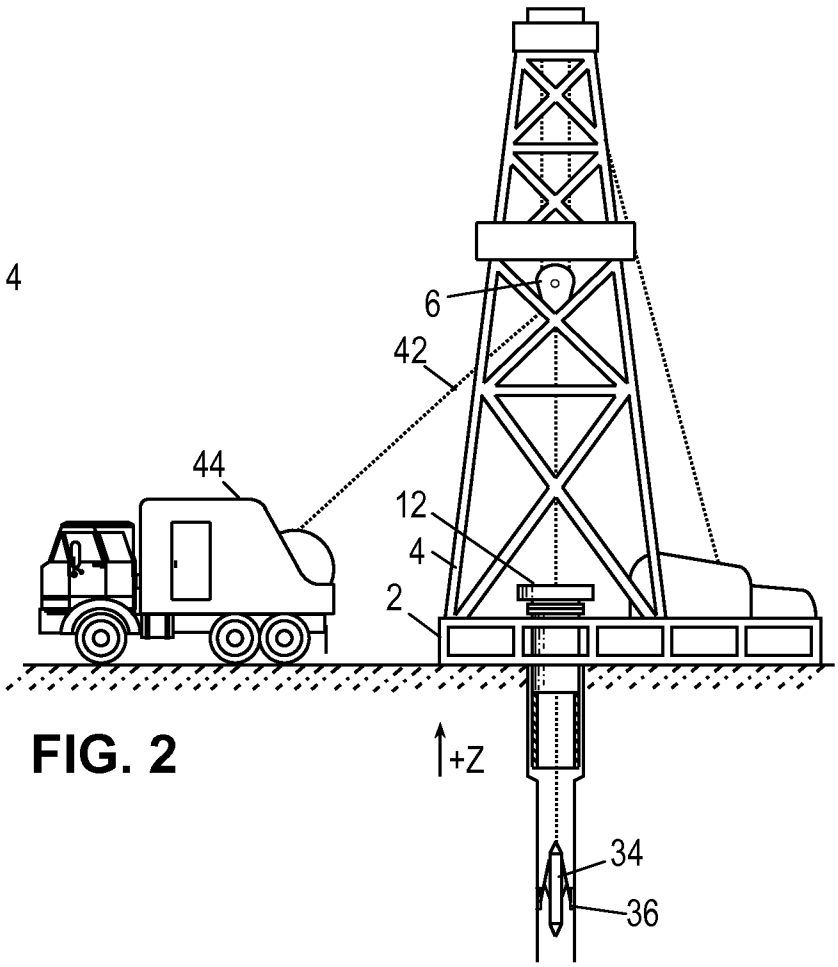

6
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36

FIG. 2

FIG. 3

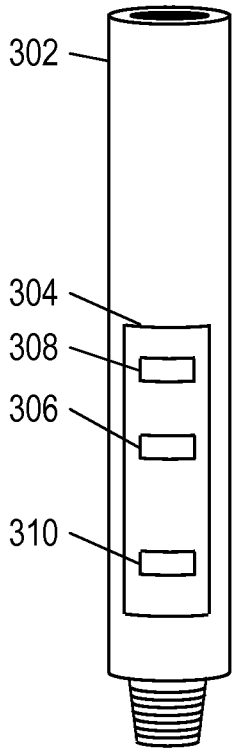


FIG. 4

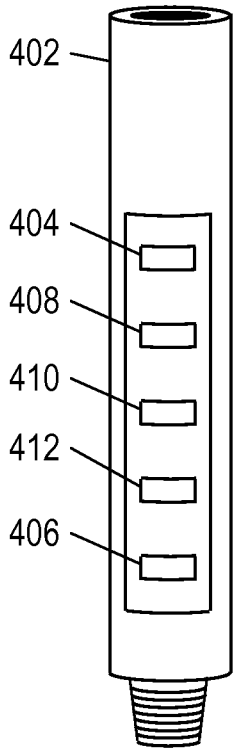
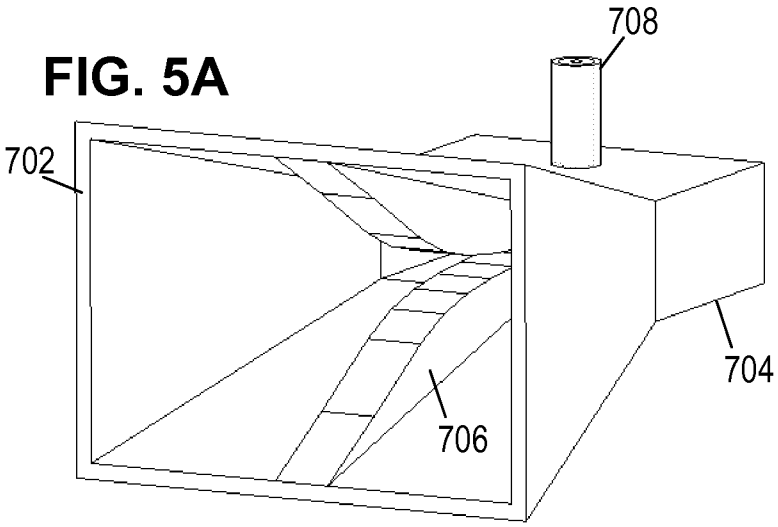


FIG. 5A



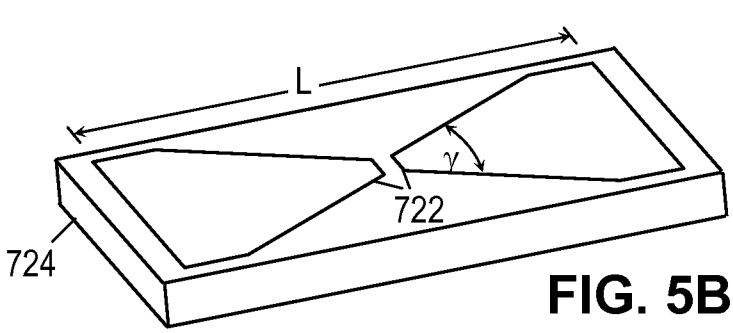


FIG. 5B

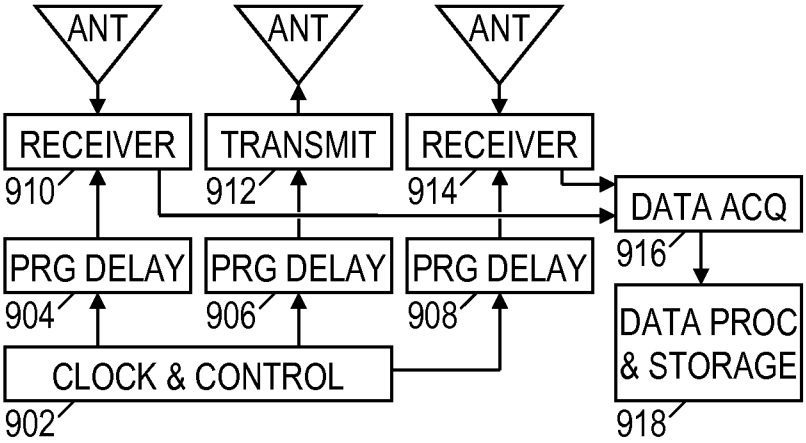
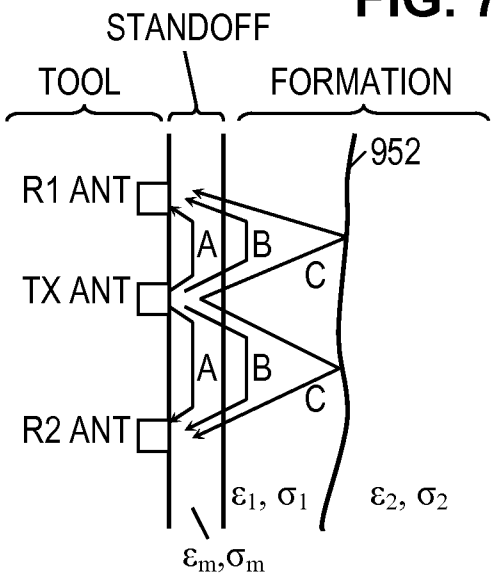


FIG. 6

FIG. 7



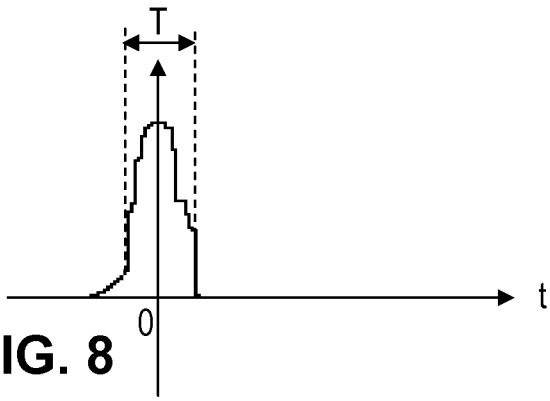


FIG. 8

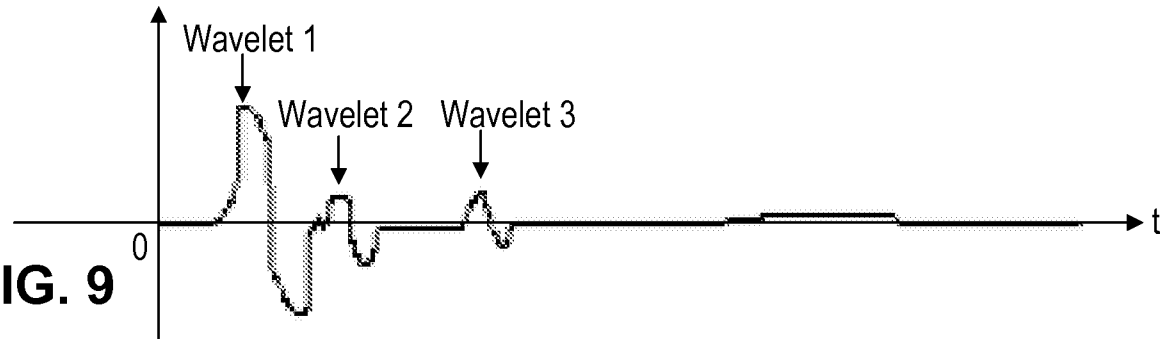


FIG. 9

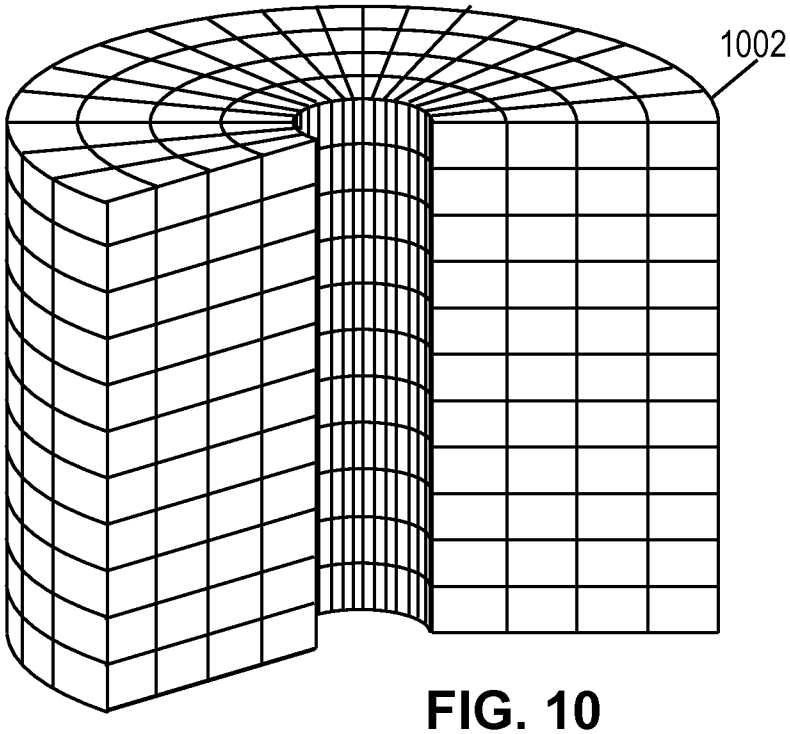


FIG. 10

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US 09/65537

A. CLASSIFICATION OF SUBJECT MATTER
IPC(8) - G01V 1/00 (2010.01)
USPC - 702/16
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)
USPC: 702/16

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
USPC: 702/7, 8, 14, 16; 367/35, 69; 340/853.5, 854.6; 324/337, 338 (keyword limited - see search terms below)

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
PubWEST (PGPB, USPT, USOC, EPAB, JPAB); GOOGLE; Google Scholar
Terms: borehole, drill, logging, imaging, 3-d, azimuthal, travel, delay, transit, eccenter, antenna, axial, pulse, electromagnetic, horn, dielectric, radial.

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 6,856,132 B2 (Appel et al.) 15 February 2005 (15.02.2005), entire document, especially abstract, col. 1, ln 18-27, col. 7, ln 50 to col. 9, ln 13, col. 9, ln 41 to col. 10, ln 35, col. 11, ln 42 to col. 12, ln 46, col. 14, ln 21-58, col. 18, ln 35-50, col. 19, ln 34-53, col. 20, ln 26-53.	1-20
Y	US 2003/0223620 A1 (Anxionnaz et al.) 04 December 2003 (04.12.2003), entire document, especially abstract, para [0004], [0005], [0006], [0078].	1-20

☐ Further documents are listed in the continuation of Box C. ☐

* Special categories of cited documents:
"A" document defining the general state of the art which is not considered to be of particular relevance
"E" earlier application or patent but published on or after the international filing date
"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)
"O" document referring to an oral disclosure, use, exhibition or other means
"P" document published prior to the international filing date but later than the priority date claimed
"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
05 January 2010 (05.01.2010)	19 JAN 2010
Name and mailing address of the ISA/US Mail Stop PCT, Attn: ISA/US, Commissioner for Patents P.O. Box 1450, Alexandria, Virginia 22313-1450 Facsimile No. 571-273-3201	Authorized officer: Lee W. Young PCT Helpdesk: 571-272-4300 PCT OSP: 571-272-7774