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[Continued on next page]

(54) Title: INVERSION-BASED METHOD TO CORRECT FOR THE PIPE RESIDUAL SIGNAL IN TRANSIENT MWD MEASUREMENTS

(57) Abstract: An apparatus and method for reducing a pipe residual signal from transient signals in an induction tool having a metallic pipe with finite, non-zero conductivity in a borehole penetrating an earth formation. The apparatus may include a transient electromagnetic (TEM) signal transmitter, at least one receiver configured to generate an output signal in response to the TEM signal, and at least one processor for estimating an updated model with an improved estimate of the resistivity property. The updated model may be estimated based on a difference between a simulated signal from an initial model and the output signal. The difference may be represented by a set of basis functions. The method includes using the apparatus.

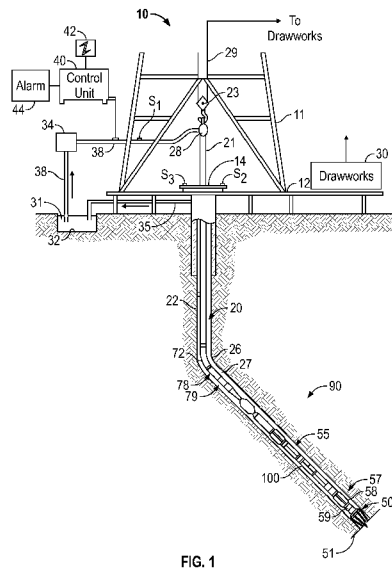


FIG. 1

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**INVERSION-BASED METHOD TO CORRECT FOR THE PIPE RESIDUAL
SIGNAL IN TRANSIENT MWD MEASUREMENTS**

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BACKGROUND OF THE DISCLOSURE

1. Field of the Disclosure

[0001] In one aspect, this disclosure generally relates methods and apparatuses for earth formation evaluation and, more specifically, for determining resistivity properties of the earth formation.

2. Background of the Art

[0002] Electromagnetic induction resistivity instruments can be used to determine the electrical conductivity of earth formations surrounding a wellbore. An electromagnetic induction well logging instrument may include a transmitter coil and a plurality of receiver coils positioned at axially spaced apart locations along the instrument housing. An alternating current may then be passed through the transmitter coil. Voltages which are induced in the receiver coils as a result of alternating magnetic fields induced in the earth formations are then measured. The magnitude of certain phase components of the induced receiver voltages are related to the conductivity of the media surrounding the instrument.

[0003] At the ultra-deep scale, a technology may be employed based on transient field behavior. The transient electromagnetic field method is widely used in surface geophysics. Typically, voltage or current pulses that are excited in a transmitter initiate the propagation of an electromagnetic signal in the earth formation. Electric currents diffuse outwards from the transmitter into the surrounding formation. At different times, information arrives at the measurement sensor from different investigation depths. Particularly, at a sufficiently late time, the transient electromagnetic field is sensitive predominantly to remote formation zones and only slightly depends on the resistivity distribution in the vicinity of the transmitter. This

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feature of transient field is especially important for logging aimed on deep depth of investigation.

[0004] In the transient measurement while drilling (MWD) measurements, the electromagnetic fields induced in the formation and in the drilling pipe are measured by two induction coils. The signals from the coils are combined in a special way to eliminate a parasitic signal from the pipe (bucking). In case of deep transient measurements, when target is placed tens of meters way from the tool, some residual signal from the pipe still presents in the late time stage of the bucked signal and can undesirably affect interpretation results if not taken into account.

[0005] There is a need for a method of reducing the pipe residual signal information acquired with real MWD tools having finite non-zero conductivity in transient field studies. The present disclosure satisfies this need.

SUMMARY OF THE DISCLOSURE

[0006] In aspects, the present disclosure is related to an apparatus and method for electromagnetic induction well logging for determining the resistivity of earth formations penetrated by a wellbore. More specifically, the present disclosure relates to reducing a pipe residual signal from transient signals in an induction tool having a metallic pipe with finite, non-zero conductivity.

[0007] One embodiment according to the present disclosure includes a method of determining a resistivity property of an earth formation, the method comprising: producing a transient electromagnetic (TEM) signal using a transmitter on a carrier conveyed in a borehole; using at least one receiver on the carrier for producing an output signal responsive to the TEM signal, the output signal being affected by a finite, non-zero conductivity of the carrier; and using at least one processor for: (i) producing a simulated signal using an initial model, the initial model including the resistivity property, (ii) representing a difference between the simulated signal and the output signal by a set of basis functions, and (iii) using the difference for estimating an updated model, the updated model including an improved estimate of the resistivity property.

[0008] Another embodiment according to the present disclosure includes an apparatus for determining a resistivity property of an earth formation, the apparatus comprising: a carrier configured to be conveyed in a borehole; a transmitter disposed on the carrier and configured to produce a transient electromagnetic (TEM) signal; at least one receiver disposed on the carrier and configured to produce an output responsive to the TEM signal; at least one processor; and a non-transitory computer readable medium with instructions thereon that, when executed by the at least one processor: produce a simulated signal using an initial model, the initial model including the resistivity property, represent a difference between the simulated signal and the output signal by a set of basis functions, and use the difference for estimating an updated model, the updated model including an improved estimate of the resistivity.

[0009] Another embodiment according to the present disclosure includes a non-transitory computer-readable medium product having instructions thereon that, when executed, cause the at least one processor to perform a method, the method comprising: producing a simulated signal using an initial model, the initial model including a resistivity property; representing a difference between the simulated signal and an output signal by a set of basis functions, wherein the output signal is produced using at least one receiver on a carrier responsive to a transient electromagnetic (TEM) signal produced using a transmitter on the carrier conveyed in a borehole and wherein the output signal is affected by a finite, non-zero conductivity of the carrier; and using the difference for estimating an updated model, the updated model including an improved estimate of the resistivity property.

[0010] Examples of the more important features of the disclosure have been summarized rather broadly in order that the detailed description thereof that follows may be better understood and in order that the contributions they represent to the art may be appreciated. There are, of course, additional features of the disclosure that will be described hereinafter and which will form the subject of the claims appended hereto.

BRIEF DESCRIPTION OF THE DRAWINGS

[0011] For a detailed understanding of the present disclosure, reference should be made to the following detailed description of the embodiments, taken in conjunction with the accompanying drawings, in which like elements have been given like numerals, wherein:

FIG. 1 shows a schematic of a drilling rig with an electric induction tool according to one embodiment of the present disclosure;

FIG. 2 shows a schematic of an electric induction tool according to one embodiment of the present disclosure;

FIG. 3 shows a chart of signal with and without pipe in a 1 ohmm homogeneous formation;

FIG. 4 shows a chart of signal with and without pipe in a 10 ohmm homogeneous formation;

FIG. 5 shows a chart of signal with and without pipe in a 100 ohmm homogeneous formation;

FIG. 6 shows a chart of with a residual signal approximation in a 1 ohmm homogenous formation according to one embodiment of the present disclosure;

FIG. 7 shows a chart of with a residual signal approximation in a 10 ohmm homogenous formation according to one embodiment of the present disclosure;

FIG. 8 shows a chart of with a residual signal approximation in a 100 ohmm homogenous formation according to one embodiment of the present disclosure;

FIG. 9 shows a chart of with a residual signal approximation formation with an ahead-place boundary between 50 ohmm and 1 ohmm layers according to one embodiment of the present disclosure; and

FIG. 10 shows a flow chart of a method of reducing an error due to a residual signal according to one embodiment of the present disclosure.

DETAILED DESCRIPTION OF THE DISCLOSURE

[0012] The present disclosure relates to apparatuses and methods for electromagnetic induction well logging for determining the resistivity of earth formations penetrated by a wellbore. More specifically, the present disclosure relates to reducing a pipe residual signal from transient signals in an induction tool having a metallic pipe with finite, non-zero conductivity. The present disclosure is susceptible to embodiments of different forms. There are shown in the drawings, and herein will be described in detail, specific embodiments of the present disclosure with the understanding that the present disclosure is to be considered an exemplification of the principles of the present disclosure and is not intended to limit the present disclosure to that illustrated and described herein.

[0013] In the present disclosure, a resistivity property may include, but is not limited to, one of: a resistivity of the formation and a distance to a bed boundary in the formation. Herein, the term “information” may relate to one or more of: (i) raw data, (ii) processed data, and (iii) signals.

[0014] In one aspect, the present disclosure relates to reducing an error in an estimation of formation parameters due to residual signals from a conductive bottom hole assembly (BHA). One benefit of the proposed technique may be more significant when a target is located tens of meters away from the tool.

[0015] The residual signal from a conductive drill may be quantified and corrected via an algorithm employing linear inversion. The error reduction algorithm may use prior knowledge about the “initial guess” (formation model). The initial guess may be obtained through a non-linear inversion in instances where measured information might be affected by the residual effect due to conductive pipe. Then, the resulting model may be used as an initial guess for the linear inversion to reduce an error due to the residual error contribution due to the conductive pipe. Additionally, the linear inversion may be repeated to obtain a next approximation if a higher degree of error compensation is desired. Another advantage of the algorithm using linear inversion may be that the algorithm may also be used to reduce errors due to system

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imperfections due to, but not limited to, tool bedding and systematic noise of electronics.

[0016] The residual signal may be filtered out using an inversion. If m unknown parameters of formation model to be denoted by M_k , then n experimental observations will be O_j . These information sets may be arranged as column matrices M and O :

$$M^T = (M_1, M_2, \dots, M_m),$$

(1)

$$O^T = (O_1, O_2, \dots, O_n).$$

(2)

where T indicates a transpose. It may be assumed that a known functional relationship, A (forward modeling), exists between the models of parameters and the observations:

$$O_j = A_j(M_1, M_2, \dots, M_m) \quad j = 1, 2, \dots, n$$

(3)

[0017] An initial guess M_k^a may be required for the model parameters:

$$M^{Ta} = (M_1^a, M_2^a, \dots, M_m^a)$$

(4)

[0018] If function A_j varies smoothly, then a Taylor series expansion may be made about the initial guess:

$$O_j = A_j(M_1^a, M_2^a, \dots, M_m^a) + \sum_{k=1}^m [\partial A_j / \partial M_k]_{M_k^a} (M_k - M_k^a) + \dots$$

(5)

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where the higher order terms indicated at the end of **eqn. 5** may be neglected in order to linearize the problem.

[0019] If the difference between observations and model computations, which are to be minimized, is expressed as y :

$$y_j = O_j - A_j(M_1^a, M_2^a \dots M_m^a) \quad j = 1, 2, \dots, n$$

(6)

then the difference in the initial approximation and the next approximation to the model parameters will be x .

$$x_k = M_k - M_k^a, \quad k = 1, 2, \dots, m$$

(7)

[0020] The first partial derivatives defined for the initial estimations M_k^a may be represented as matrix \hat{A} of Jacobians with a size of $[m \times n]$ with elements A_{jk} :

$$\hat{A} = \begin{bmatrix} \partial A_1 / \partial M_1 & \partial A_1 / \partial M_2 & \dots & \partial A_1 / \partial M_m \\ \partial A_2 / \partial M_1 & \partial A_2 / \partial M_2 & \dots & \partial A_2 / \partial M_m \\ \dots & \dots & \dots & \dots \\ \partial A_n / \partial M_1 & \partial A_n / \partial M_2 & \dots & \partial A_n / \partial M_m \end{bmatrix}$$

(8)

$$A_{jk} = \partial A_j / \partial M_k$$

(9)

[0021] **Eqns. 6-8** may be combined and expressed as:

$$\vec{y} = \hat{A} \vec{x}$$

(10)

and the solution to the **eqn. 10** is:

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$$\bar{x} = \hat{A}^{-1}\bar{y}$$

(11)

[0022] If initial guess is not good enough, i.e., the difference in a least squares sense between the observations O and y exceeds a specified threshold value, then the next approximation may be obtained as:

$$M_k^b = x_k + M_k^a, \quad k = 1, 2, \dots, m.$$

(12)

[0023] In some circumstances, functional relationship, A , between the models of parameters and the observations may not be exactly known. Under these circumstances, A may be defined using:

$$O_j - P_j = A_j(M_1, M_2, \dots, M_m) \quad j = 1, 2, \dots, n,$$

(13)

where P_j is a vector that can be presented as a linear combination of some basis functions $f(t) = 1/t^{i-1/2}$, $i = 1, 2, \dots, p$ and some number p of unknown coefficients $M_{m+1}, M_{m+2}, \dots, M_{m+p}$:

$$P(t_j) = \sum_{i=1}^{i=p} \frac{M_{m+i}}{t_j^{i-1/2}}, \quad i = 1, 2, \dots, p$$

(14)

[0024] The approximation in **eqn. 14** follows from analysis of the solution for the signal measured at the late stage in the receiver when both transmitter and receiver coils are placed on the pipe and surrounding formation is homogeneous.

[0025] **Eqn. 10** may be modified to use A of **eqn. 14** to create an expression for the circumstances expressed with **eqn. 13**. Thus, we have:

$$\bar{y} = \hat{A}_p \bar{x}_p,$$

(15)

where modified matrix \hat{A}_p may be represented as:

$$\hat{A} = \begin{bmatrix} \partial A_1 / \partial M_1 & \partial A_1 / \partial M_2 & \dots & \partial A_1 / \partial M_m, & 0 & 0 & \dots & 0 \\ \partial A_2 / \partial M_1 & \partial A_2 / \partial M_2 & \dots & \partial A_2 / \partial M_m, & 0 & 0 & \dots & 0 \\ \cdot & & & & & & & \\ \partial A_{n-l} / \partial M_1 & \partial A_{n-l} / \partial M_2 & \dots & \partial A_{n-l} / \partial M_m, & 1/t_{n-l}^{1/2} & 1/t_{n-l}^{3/2} & \dots & 1/t_{n-l}^{p-1/2} \\ \cdot & & & & & & & \\ \cdot & & & & & & & \\ \partial A_n / \partial M_1 & \partial A_n / \partial M_2 & \dots & \partial A_n / \partial M_m, & 1/t_n^{1/2} & 1/t_n^{3/2} & \dots & 1/t_n^{p-1/2} \end{bmatrix},$$

(16)

where modified vector \vec{x}_p may be defined as:

$$\vec{x}_p = \vec{x} + \vec{x}_t,$$

(17)

$$\vec{x} = ((M_1 - M_1^a), (M_2 - M_2^a), \dots, (M_m - M_m^a))$$

(18)

$$\vec{x}_t = (M_{m+1}, M_{m+2}, \dots, M_{m+p}).$$

(19)

[0026] By solving **eqn. 15**, both corrections for parameters of formation $\vec{x}_k = M_k - M_k^a$ and coefficients $\vec{x}_t = (M_{m+1}, M_{m+2}, \dots, M_{m+p})$ may be obtained.

[0027] The residual signals, \vec{y} , may be estimated by taking a difference between the two signals presented in **Figs. 3-5** (discussed below) and then, solving a least square problem with respect to the coefficients

$$M_i, \quad i = 1, \dots, p$$

$$\vec{y} = \hat{T}\vec{x}_t, \quad ,$$

where $\vec{x}_t = (M_1, M_2, \dots, M_p)$ and matrix \hat{T} is comprised of odd half powers of time:

$$\hat{T} = \begin{bmatrix} 1/t_{n-l}^{1/2} & 1/t_{n-l}^{3/2} & \dots & 1/t_{n-l}^{p-1/2} \\ 1/t_{n-l+1}^{1/2} & 1/t_{n-l+1}^{3/2} & \dots & 1/t_{n-l+1}^{p-1/2} \\ . & . & . & . \\ 1/t_n^{1/2} & 1/t_n^{3/2} & \dots & 1/t_n^{p-1/2} \end{bmatrix}$$

The time interval may be from $t = t_{n-l}$ to $t = t_n$ and l is the number of discrete time points where signal is performed.

[0028] In general, a time moment, t_{n-l} , may be unknown and may be a subject for inversion as well. This means that **eqn. 15** may be solved for multiple instances each with a different value of t_{n-l} , and the instance which provides the smallest misfit is the solution. Depending on the formation resistivity, the typical values of t_{n-l} may be in the interval from 0.5e-04 to 3e-04 seconds. Most cases may be solved while selecting t_{n-l} around 1e-04 seconds. Typically, all linear inversions are performed with the same initial guess and performing a linear inversion will consume significantly less time compared to performing a nonlinear inversion. For nonlinear inversions, providing the initial guess may be performed at the first step when the residual signal from the pipe may be present in the data as a systematic noise.

[0029] Since this inversion-based approach to reducing errors in formation parameters does not rely on any specific cause for the existence of the uncompensated signal, the error reduction may also be used to compensate for imperfections in transient signals caused by the tool bedding, systematic noise of electronics, etc.

[0030] Figure 1 shows a schematic diagram of a drilling system **10** with a carrier **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 term “carrier” as used herein means any device, device component, combination of devices, media and/or member that may be used to convey, house, support, or otherwise facilitate the use of another device, device component, combination of devices, media and/or member. Exemplary non-limiting carriers include drill strings

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of the coiled tube type, of the jointed pipe type, and any combination or portion thereof. Other carrier examples include casing pipes, wirelines, wireline sondes, slickline sondes, drop shots, downhole subs, BHAs, drill string inserts, modules, internal housings, and substrate portions thereof. The BHA **90** may include a tool **100** configured for performing electric induction measurements. 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 carrier (shown here as a 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 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 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.

[0031] 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 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 S_1 preferably placed in the line **38** provides information about the fluid flow rate. A surface torque sensor S_2 and a sensor S_3 associated with the drillstring **20** respectively provide information about the torque and rotational

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speed of the drillstring. Additionally, a sensor (not shown) associated with line **29** is used to provide the hook load of the drillstring **20**.

[0032] In one embodiment of the disclosure, the drill bit **50** is rotated by only rotating 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.

[0033] In the preferred embodiment of Figure **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 **55** 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 **50**. A stabilizer **58** coupled to the bearing assembly **57** acts as a centralizer for the lowermost portion of the mud motor assembly.

[0034] 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 preferably 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**.

[0035] 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

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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**.

[0036] 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** preferably includes a computer or a microprocessor-based processing system, memory for storing programs or models and information, a recorder for recording information, and other peripherals. The control unit **40** is preferably adapted to activate alarms **44** when certain unsafe or undesirable operating conditions occur.

[0037] **Fig. 2** shows a schematic of tool **100**. The tool **100** may include a transmitter **210** and at least two receiver coils **220, 230** disposed along drillstring **20**. The transmitter **210** may be configured to impart a transient electromagnetic signal into an earth formation. The at least two receiver coils **220, 230** may be configured to receive a transient electromagnetic signal from the earth formation and convert the received signal into an output signal. Tool **100** may have the following non-limiting exemplary parameters:

Pipe radius = 7 cm

Pipe thickness = 3 cm

Resistivity of drill = 0.714 E-06 ohmm

Resistivity of copper = 1.7 E-08 ohmm

Copper length - 0.75 m

Ferrite magnetic permeability = 100

Ferrite length - 0.10 m

Ferrite thickness - 1.5 cm

Transmitter/Receiver coils radius = 8.5 cm, Transmitter current = 1 A

First receiver spacing is 5 m from the transmitter

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Second receiver spacing is 7 m from the transmitter

[0038] **Figs. 3-5** show a chart of curves representing modeling results where an output signal (a bucked signal) in the presence of homogeneous formation is compared with a one dimensional signal from the earth formation in the absence of conductive pipe. The bucked signal may be obtained by combining the signals from the two receivers using known methods. In one embodiment of the disclosure, a weighted combination of the two signals may be used. In **Fig. 3**, curve **310** is a modeled signal with conductive pipe, and curve **320** is a modeled signal without conductive pipe. The undercompensated pipe has an effect on the signal which may be observed to begin at about 2 milliseconds in a homogeneous formation with a resistivity of 1 ohmm. Similarly, in **Fig. 4**, curve **410** is a modeled signal with conductive pipe, and curve **420** is a modeled signal without conductive pipe. In a homogeneous formation with a resistivity of about 10 ohmm, the undercompensated pipe has an effect on the signal that may be observed beginning at 0.1 milliseconds. In **Fig. 5**, curve **510** is a modeled signal with conductive pipe, and curve **520** is a modeled signal without conductive pipe. In a homogeneous formation with a resistivity of about 100 ohmm, the undercompensated pipe has an effect on the signal that may be observed beginning at 0.05 milliseconds. The uncompensated residual signal may represent a systematic noise that affects interpretation results if not taken into account.

[0039] **Fig. 6** shows a chart of curves representing estimates of residual signals when the number of terms, p , in the series of **eqn. 14** varies from 2 to 5 according to one embodiment of the present disclosure. Curve **610** represents the residual signal in a 1 ohmm formation. Curve **620** represents an estimated residual signal using 2 terms. Curve **630** represents an estimated residual signal using 3 terms. Curve **640** represents an estimated residual signal using 4 terms. Curve **650** represents an estimated residual signal using 5 terms. It may be observed that curve **640** may provide a satisfactory fit with curve **610** below 3 milliseconds.

[0040] **Fig. 7** shows a chart of curves representing estimates of residual signals when the number of terms, p , in the series of **eqn. 14** varies from 2 to 5 according to one

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embodiment of the present disclosure. Curve **710** represents the residual signal in a 10 ohmm formation. Curve **720** represents an estimated residual signal using 2 terms. Curve **730** represents an estimated residual signal using 3 terms. Curve **740** represents an estimated residual signal using 4 terms. Curve **750** represents an estimated residual signal using 5 terms. It may be observed that curve **740** may provide a satisfactory fit with curve **710** below 3 milliseconds.

[0041] **Fig. 8** shows a chart of curves representing estimates of residual signals when the number of terms, p , in the series of **eqn. 14** varies from 2 to 5 according to one embodiment of the present disclosure. Curve **810** represents the residual signal in a 1 ohmm formation. Curve **820** represents an estimated residual signal using 2 terms. Curve **830** represents an estimated residual signal using 3 terms. Curve **840** represents an estimated residual signal using 4 terms. Curve **850** represents an estimated residual signal using 5 terms. It may be observed that curve **840** may provide a satisfactory fit with curve **810** below 3 milliseconds.

[0042] **Fig. 9** shows a chart of curves representing estimates of residual signals when the number of terms, p , in the series of **eqn. 14** varies from 2 to 5 according to one embodiment of the present disclosure. Curve **910** represents the residual signal when the tool **100** is placed in a resistive 50 ohmm layer and a 1 ohmm conductive layer is placed 30 meters ahead of the tool **100**. Curve **920** represents an estimated residual signal using 2 terms. Curve **930** represents an estimated residual signal using 3 terms. Curve **940** represents an estimated residual signal using 4 terms. Curve **950** represents an estimated residual signal using 5 terms. Again, it may be observed that curve **940** may provide a satisfactory fit with curve **910** below 3 milliseconds.

[0043] **Fig. 10** shows of flow chart of a method **1000** according to one embodiment of the present disclosure. In step **1010**, a TEM signal may be transmitted into an earth formation by transmitter **210** in a borehole **26**. In step **1020**, at least one receiver **220**, **230** may produce an output signal in response to a received TEM signal. In step **1030**, a simulated signal (initial guess) may be produced using an initial model that includes a resistivity property. The initial model may use a nonlinear inversion. In step **1040**, the difference between the output signal of step **1020** and the simulated

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signal of step **1030** may be represented as a set of basis functions. In step **1050**, the model may be updated with an improved estimate for the resistivity property using the difference represented by the basis functions. In some embodiments, step **1030** may be performed before step **1020** or before step **1010**.

[0044] While the disclosure has been described with reference to exemplary embodiments, it will be understood that various changes may be made and equivalents may be substituted for elements thereof without departing from the scope of the disclosure. In addition, many modifications will be appreciated to adapt a particular instrument, situation or material to the teachings of the disclosure without departing from the essential scope thereof. Therefore, it is intended that the disclosure not be limited to the particular embodiment disclosed as the best mode contemplated for carrying out this disclosure, but that the disclosure will include all embodiments falling within the scope of the appended claims.

[0045] While the foregoing disclosure is directed to the one mode embodiments of the disclosure, various modifications will be apparent to those skilled in the art. It is intended that all variations within the scope of the appended claims be embraced by the foregoing disclosure.

THE CLAIMS

We claim:

1. A method of determining a resistivity property of an earth formation, the method comprising:
 - producing a transient electromagnetic (TEM) signal using a transmitter on a carrier conveyed in a borehole;
 - using at least one receiver on the carrier for producing an output signal responsive to the TEM signal, the output signal being affected by a finite, non-zero conductivity of the carrier; and
 - using at least one processor for:
 - (i) producing a simulated signal using an initial model, the initial model including the resistivity property,
 - (ii) representing a difference between the simulated signal and the output signal by a set of basis functions, and
 - (iii) using the difference for estimating an updated model, the updated model including an improved estimate of the resistivity property.
2. The method of claim 1 wherein the set of basis functions comprises $t^{-n/2}$ where t is a time and n is an integer.
3. The method of claim 1 further comprising using, for the at least one receiver, a first receiver and a second receiver.
4. The method of claim 1 further comprising:
 - estimating the initial model by an inversion of the output signal.
5. The method of claim 1, further comprising:
 - estimating the updated model by an inversion of the difference between the simulated signal and the output signal.

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6. The method of claim 5, wherein the inversion is selected from: (i) a one-dimensional inversion, or (ii) a two-dimensional inversion.
7. An apparatus for determining a resistivity property of an earth formation, the apparatus comprising:
 - a carrier configured to be conveyed in a borehole;
 - a transmitter disposed on the carrier and configured to produce a transient electromagnetic (TEM) signal;
 - at least one receiver disposed on the carrier and configured to produce an output responsive to the TEM signal;
 - at least one processor; and
 - a non-transitory computer readable medium with instructions thereon that, when executed by the at least one processor:
 - produce a simulated signal using an initial model, the initial model including the resistivity property,
 - represent a difference between the simulated signal and the output signal by a set of basis functions, and
 - use the difference for estimating an updated model, the updated model including an improved estimate of the resistivity.
8. The apparatus of claim 7 wherein the set of basis functions comprises $t^{-n/2}$ where t is a time and n is an integer.
9. The apparatus of claim 7 further comprising using, for the at least one receiver, a first receiver and a second receiver.
10. The apparatus of claim 7, wherein the non-transitory computer-readable medium further comprises instructions that, when executed, cause the at least one processor to:
 - estimate the initial model by an inversion of the output signal.

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11. The apparatus of claim 7, wherein the non-transitory computer-readable medium further comprises instructions that, when executed, cause the at least one processor to:

estimate the updated model by an inversion of the difference between the simulated signal and the output signal.

12. The apparatus of claim 11, wherein the inversion is in at least one dimension.

13. A non-transitory computer-readable medium product having instructions thereon that, when executed, cause the at least one processor to perform a method, the method comprising:

producing a simulated signal using an initial model, the initial model including a resistivity property;

representing a difference between the simulated signal and an output signal by a set of basis functions, wherein the output signal is produced using at least one receiver on a carrier responsive to a transient electromagnetic (TEM) signal produced using a transmitter on the carrier conveyed in a borehole and wherein the output signal is affected by a finite, non-zero conductivity of the carrier; and

using the difference for estimating an updated model, the updated model including an improved estimate of the resistivity property.

14. The non-transitory computer-readable medium product of claim 13 further comprising at least one of: (i) a ROM, (ii) an EPROM, (iii) an EEPROM, (iv) a flash memory, or (v) an optical disk.

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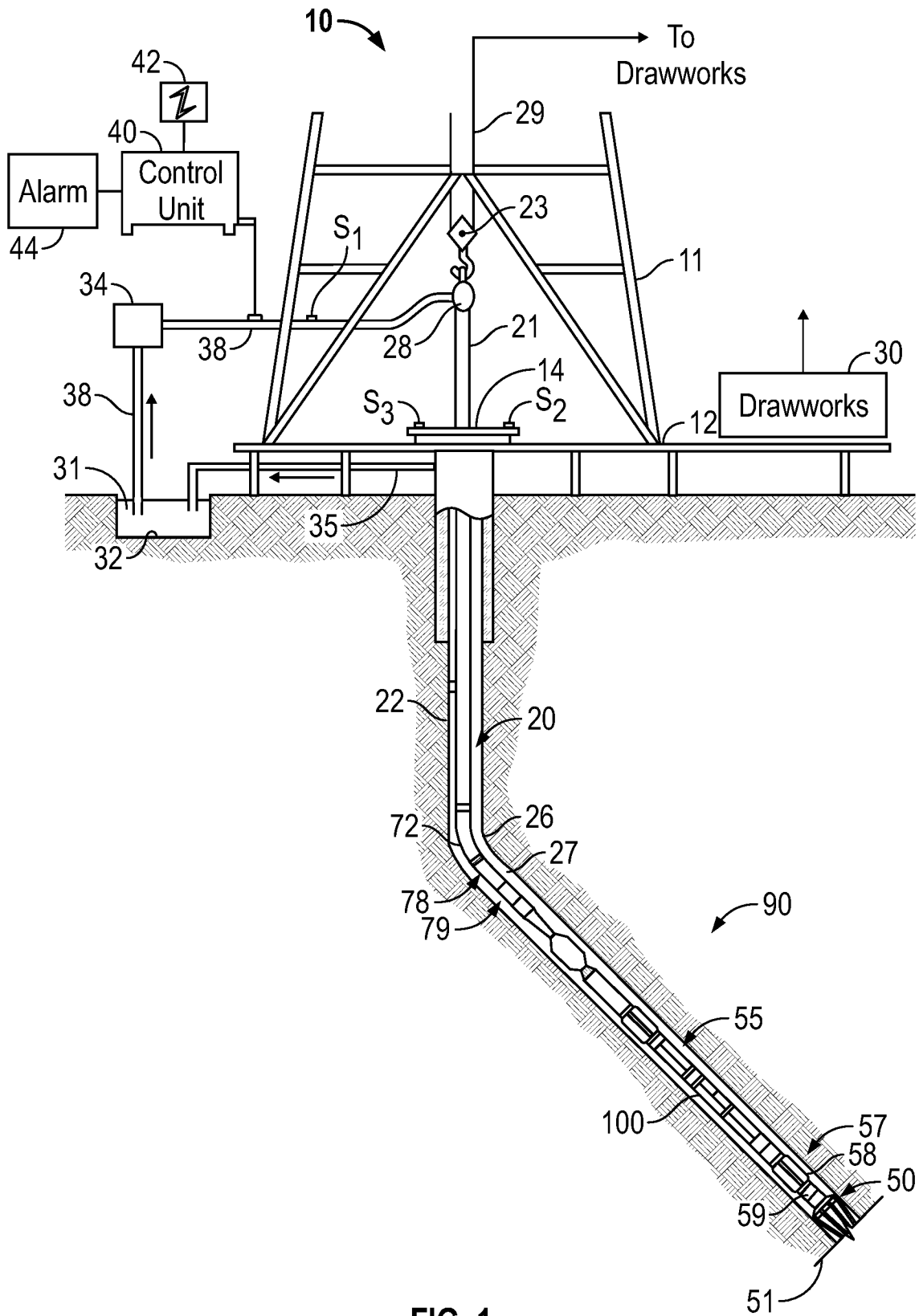


FIG. 1

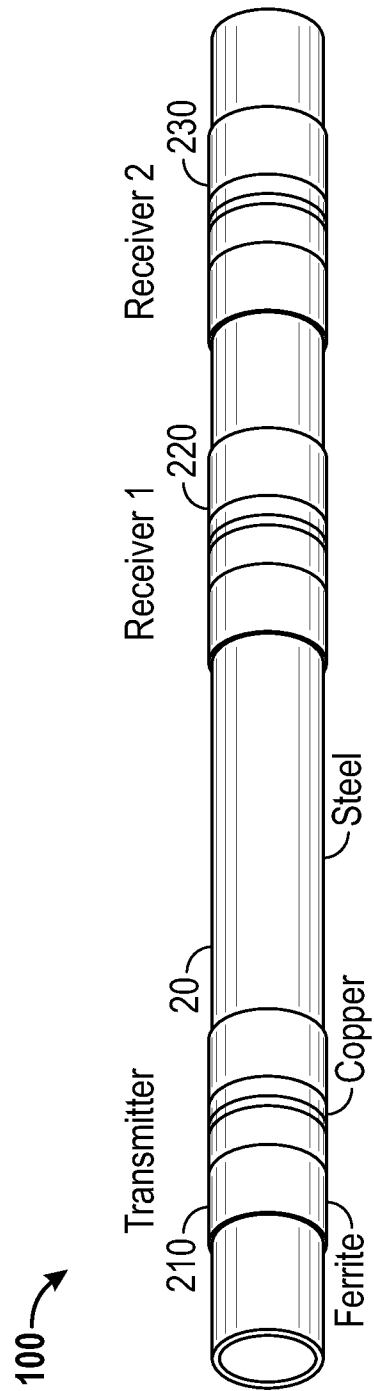


FIG. 2

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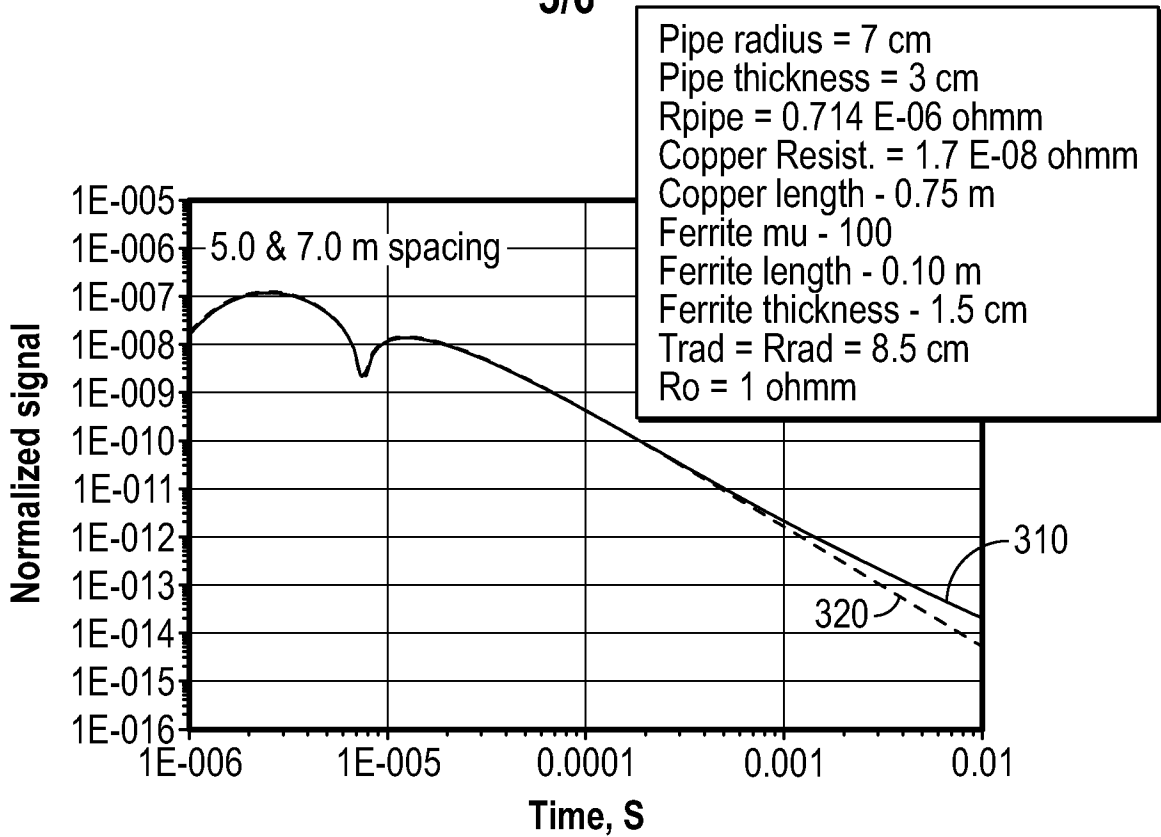


FIG. 3

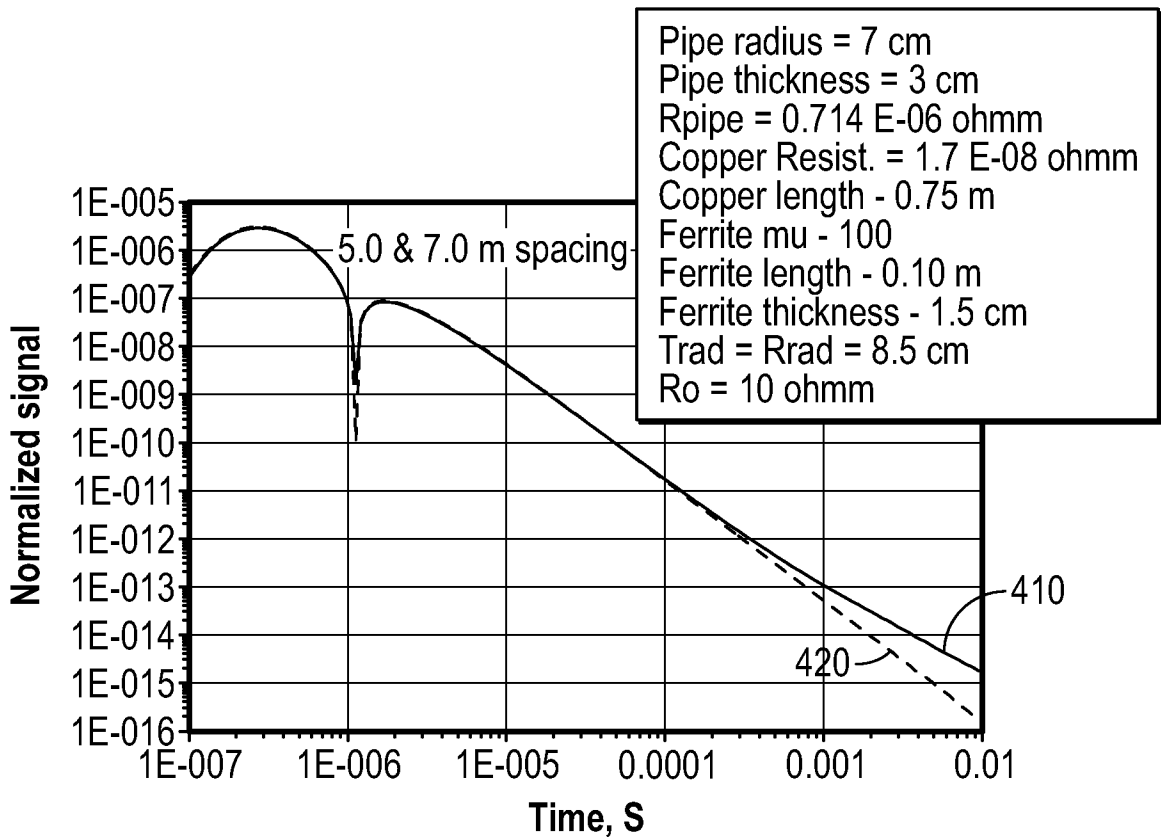


FIG. 4

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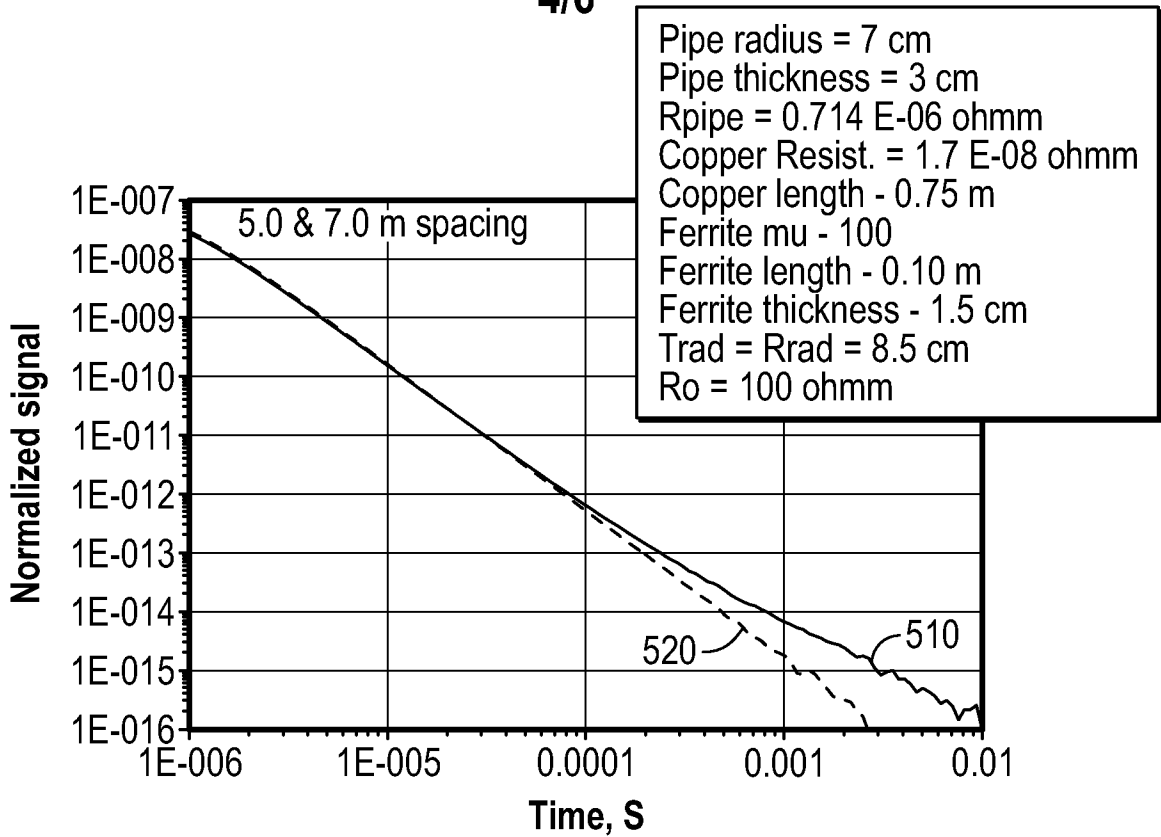


FIG. 5

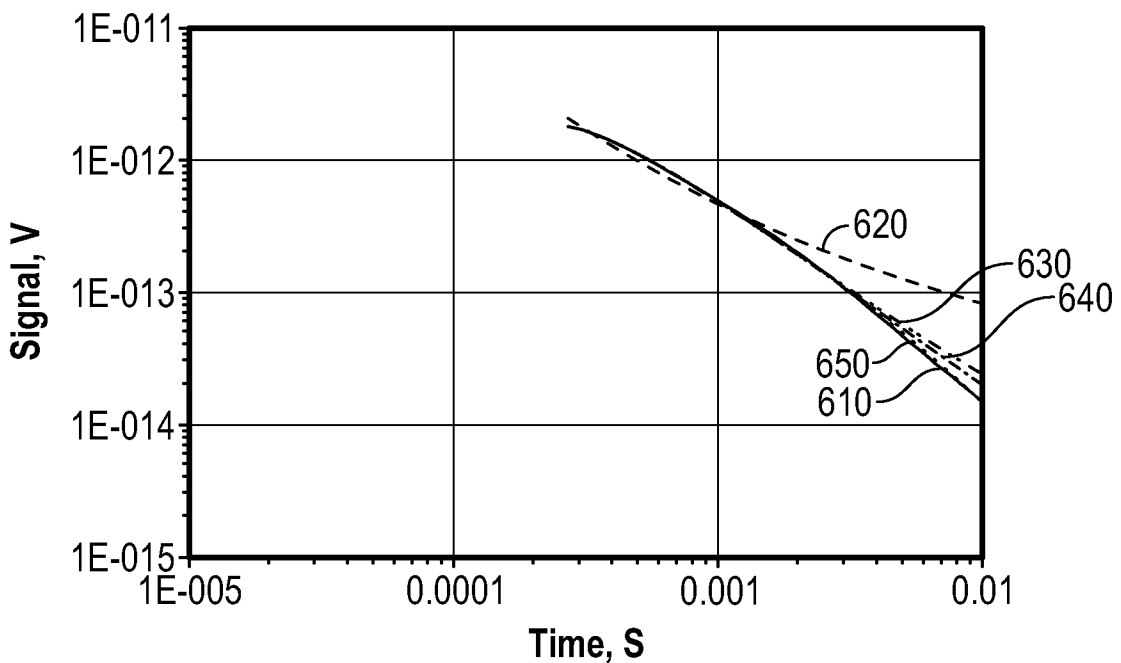


FIG. 6

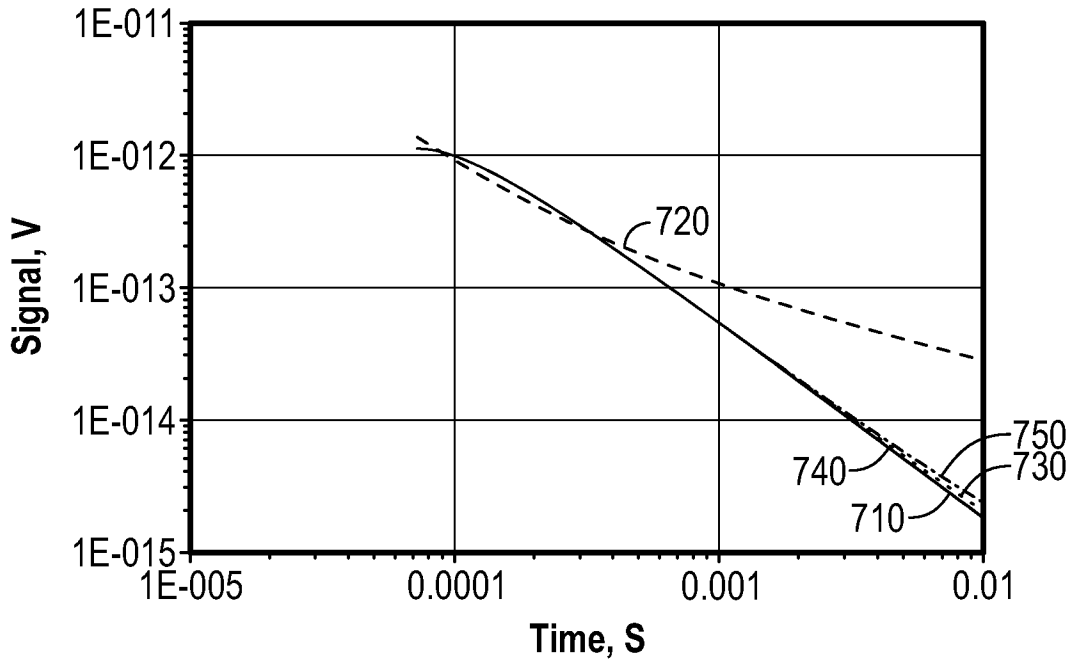


FIG. 7

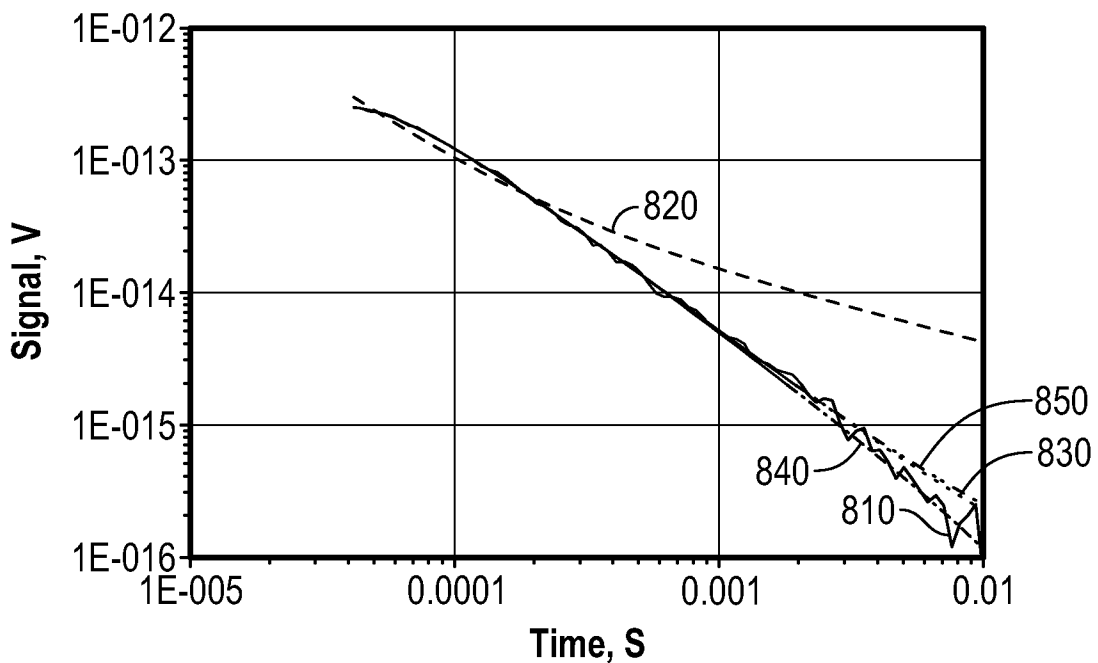


FIG. 8

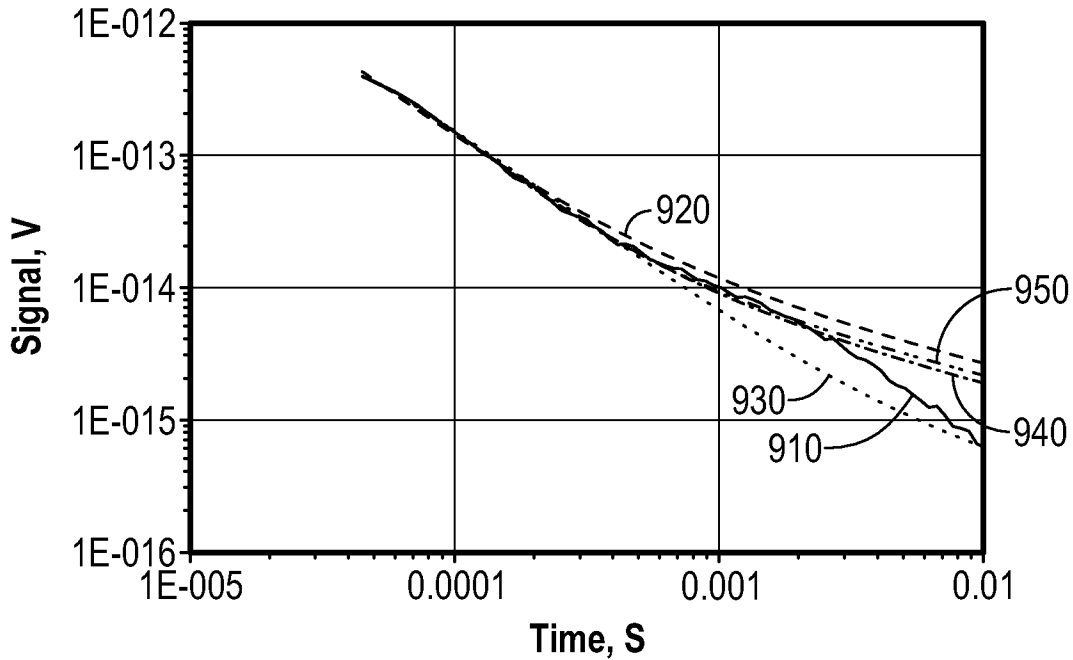


FIG. 9

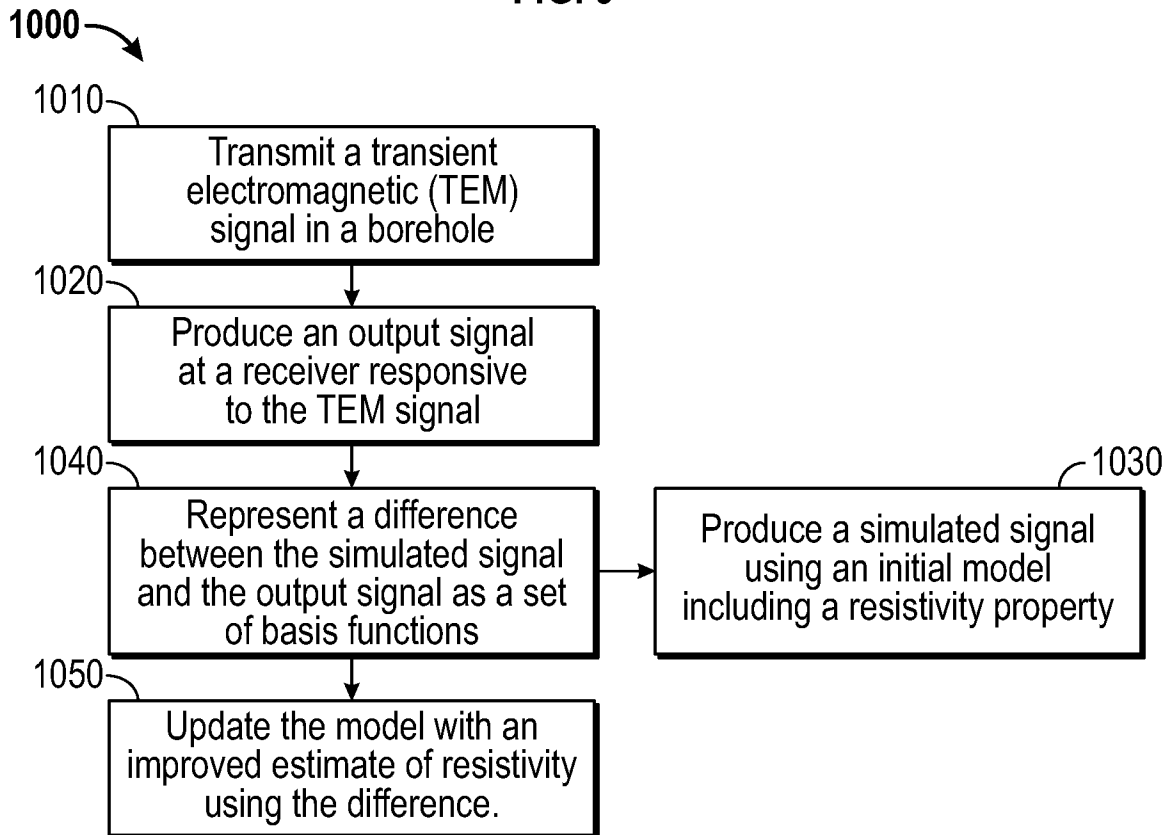


FIG. 10