



- (51) **International Patent Classification:**
E21B 47/12 (2006.01) *E21B 47/13* (2012.01)
- (21) **International Application Number:**
PCT/US2015/051699
- (22) **International Filing Date:**
23 September 2015 (23.09.2015)
- (25) **Filing Language:** English
- (26) **Publication Language:** English
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- (81) **Designated States** (*unless otherwise indicated, for every kind of national protection available*): AE, AG, AL, AM, AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ, CA, CH, CL, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT,

HN, HR, HU, ID, IL, IN, IR, IS, JP, KE, KG, KN, KP, KR, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME, MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA, SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(84) Designated States (*unless otherwise indicated, for every kind of regional protection available*): ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

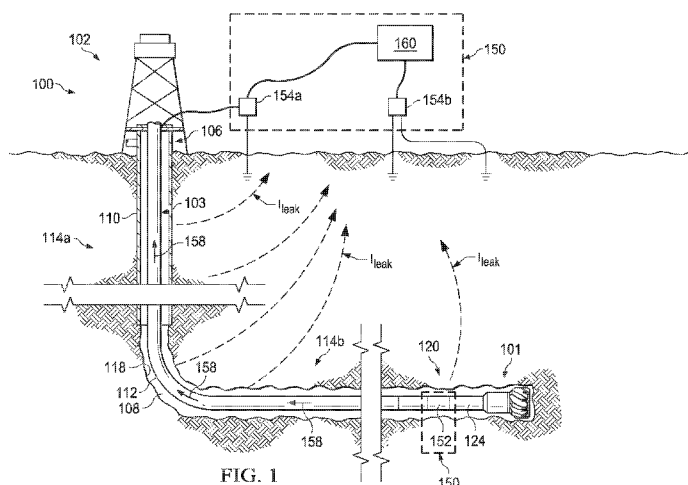
Declarations under Rule 4.17:

- *as to the identity of the inventor (Rule 4.17(i))*
- *as to applicant's entitlement to apply for and be granted a patent (Rule 4.17(ii))*
- *of inventorship (Rule 4.17(iv))*

Published:

- with international search report (Art. 21(3))

(54) Title: OPTIMIZATION OF ELECTROMAGNETIC TELEMETRY IN NON-VERTICAL WELLS



(57) Abstract: An electromagnetic telemetry system may include an electrically conductive member, a transmitter coupled to the electrically conductive member, the transmitter configured to induce an alternating current along the electrically conductive member, the alternating current representing encoded information, a first receiver coupled to the electrically conductive member, the first receiver configured to receive electromagnetic waves resulting from the alternating current, a second receiver positioned at a location apart from the first receiver, the second receiver configured to receive the electromagnetic waves resulting from the alternating current, and a receiver processing system communicatively coupled to the first receiver and the second receiver, the receiver processing system configured to process the electromagnetic waves received by the first receiver and the second receiver into a combined signal, and decode the combined signal.

OPTIMIZATION OF ELECTROMAGNETIC TELEMETRY IN NON- VERTICAL WELLS

TECHNICAL FIELD

5 The present disclosure relates generally to electromagnetic telemetry and, more particularly, to a system and method for optimizing electromagnetic telemetry in non-vertical wells.

BACKGROUND

10 Natural resources, such as hydrocarbons and water, are commonly obtained from subterranean formations that may be located onshore or offshore. The development of subterranean operations and the processes involved in removing natural resources typically involve a number of different steps such as, for example, drilling a borehole at a desired well site, treating the borehole to optimize production
15 of the natural resources, and performing the necessary steps to produce and process the natural resources from the subterranean formation.

 When performing subterranean operations, it may be desirable to communicate information from within the wellbore to systems located outside of the wellbore such as, for example, a well operation system located at or near the well
20 surface. One method of communicating information outside of the wellbore is electromagnetic telemetry.

BRIEF DESCRIPTION OF THE DRAWINGS

 A more complete and thorough understanding of the various embodiments and
25 advantages thereof may be acquired by referring to the following description taken in conjunction with the accompanying drawings, in which like reference numbers indicate like features, and wherein:

 FIGURE 1 is an elevation view of an exemplary electromagnetic telemetry system associated with a well system;

30 FIGURE 2A is a graph including plots of exemplary signals received by an electromagnetic telemetry system with two receivers;

FIGURE 2B is a graph including a plot of an exemplary combined signal of an electromagnetic telemetry system; and

FIGURE 3 is an isometric view of an exemplary electromagnetic telemetry system with an array of receivers associated with a well system.

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DETAILED DESCRIPTION

The present disclosure describes systems and methods for optimizing electromagnetic telemetry in non-vertical wells. During subterranean operations, downhole components may measure and/or collect information from within the wellbore. For example, during the drilling of a wellbore, logging tools at or near the end of a drill string may evaluate and/or monitor drilling equipment, downhole conditions, and/or the surrounding formation in what is commonly referred to as logging while drilling (LWD) or measurement while drilling (MWD). Downhole components may use electromagnetic telemetry to communicate information to the well surface. Specifically, a transmitter within the wellbore may create signals in the form alternating current along an electrically conductive member within the wellbore, such as a drill string, casing string, or production tubing, extending to the well surface. A receiver at or near the well surface may detect electromagnetic waves created by the alternating current as the current travels to the well surface. A receiver processing system coupled to the receiver may process and/or store the electromagnetic waves to determine the information transmitted.

Placing one or more additional receivers at the well surface above the non-vertical portions of a wellbore may improve the reception of the electromagnetic telemetry system as the additional receivers may detect portions of the electromagnetic waves that dissipate into the formation surrounding the wellbore. Combining the electromagnetic waves received by the receivers may result in higher combined signal reception. Additionally, when signals from different receivers are combined, the noise portions of the signals may be out of phase or at different frequencies such that some of the noise may cancel each other out. Thus, adding receivers to the electromagnetic telemetry system may improve the overall signal transmission of the telemetry system and help ensure reliable communication from

various downhole components located within the wellbore. Additional receivers may have the added benefit of allowing the electromagnetic telemetry system to track the location of the transmitter based on the relevant strength and/or arrival time of the signal at the different receivers. Embodiments of the present disclosure and its
5 advantages may be understood by referring to FIGURES 1 through 3, where like numbers are used to indicate like and corresponding parts.

FIGURE 1 illustrates an elevation view of an example embodiment of an electromagnetic telemetry system used in an illustrative wellbore environment. Well system 100 may include well surface or well site 106. Various types of equipment
10 such as rotary table, drilling fluid or production fluid pumps, drilling fluid tanks (not expressly shown), and other drilling or production equipment may be located at well surface or well site 106. For example, well surface 106 may include drilling rig 102 that has various characteristics and features associated with a land drilling rig. Although well system 100 is illustrated as a land based system, electromagnetic
15 telemetry systems incorporating teachings of the present disclosure may be satisfactorily used with offshore production systems located on offshore platforms, drill ships, semi-submersibles, and drilling barges (not expressly shown).

Well system 100 may include wellbore 114 extending into formation 130. Wellbore 114 may include generally vertical wellbore 114a or generally horizontal
20 wellbore 114b, or any combination thereof. Various directional drilling techniques may be used to form generally non-vertical portions of wellbore 114. The term directional drilling may be used to describe drilling a wellbore or portions of a wellbore that extend at a desired angle or angles relative to vertical. The desired angles may be greater than normal variations associated with vertical wellbores.
25 Directional drilling may also be described as drilling a wellbore deviated from vertical. The term horizontal drilling may be used to include drilling in a direction approximately ninety degrees (90°) or greater from vertical.

Wellbore 114 may be defined in part by a casing string 110 that may extend from well surface 106 to a selected downhole location. Downhole may be used to
30 refer to a portion of wellbore 114 that is further from well surface 106 along the length of wellbore 114 and uphole may be used to refer to a portion of wellbore 114

that is closer to well surface 106. Portions of wellbore 114, as shown in FIGURE 1, that do not include casing string 110 may be described as open hole. Various types of drilling fluid may be pumped from well surface 106 through drill string 103 to attached drill bit 101. Such drilling fluids may be directed to flow from drill string
5 103 to respective nozzles (not expressly shown) included in drill bit 101. The drilling fluid may be circulated back to well surface 106 through an annulus 108 defined in part by outside diameter 112 of drill string 103 and inside diameter 118 of wellbore 114a. Inside diameter 118 may be referred to as the sidewall of wellbore 114a. Annulus 108 may also be defined by outside diameter 112 of drill string 103 and
10 inside diameter 118 of casing string 110.

Well system 100 may also include an electrically conductive member extending from a downhole location to well surface 106. For example, drill string 103 may extend from drilling rig 102 at well surface 106 to a downhole location of wellbore 114. Drill string 103 may be made from an electrically conductive material,
15 such as steel, so that electric current may travel through drill string 103 between a downhole location and well surface 106. Electromagnetic telemetry systems incorporating teachings of the present disclosure may be satisfactorily used with any other electrically conductive member positioned within wellbore 114, such as, for example, casing string 110 and/or a production tubing (not expressly shown).

20 Downhole components may be placed within wellbore 114 to measure and/or collect information relating to formation 130, wellbore 114, and well operations. For example, in addition to a variety of components configured to form wellbore 114, such as drill bit 101, coring bits, drill collars, rotary steering tools, directional drilling tools, downhole drilling motors, reamers, and/or hole enlargers, bottom hole assembly
25 (BHA) 120 of drill string 103 may also include well logging component 124. Well logging component 124 may contain one or more sensors for monitoring petrophysical properties of formation 130, by measuring, for example, acoustic, electrical, neutron, gamma ray, photoelectric, nuclear magnetic resonance, temperature, pressure, and/or other properties. One or more sensors within well
30 logging component 124 may monitor conditions within wellbore 114 and/or drilling equipment to, for example, optimize drilling operations.

Well system 100 may also include electromagnetic telemetry system 150 for communicating information from within the wellbore to well surface 106. Electromagnetic telemetry system 150 may include transmitter 152, one or more receivers 154, and receiver processing system 160. Transmitter 152 may be positioned
5 downhole within wellbore 114, while receivers 154 and receiver processing system 160 may be positioned uphole, at or near well surface 106. Transmitter 152 may transmit signals in the form of alternating current that flows along an electrically conductive member (e.g., drill string 103) to well surface 106. The current may generate electromagnetic waves detectible by receivers 154 uphole. Receiver
10 processing system 160 may communicatively couple to receivers 154 to store and/or process the electromagnetic waves received.

Information from downhole components, such as well logging component 124, may be communicated uphole to well surface 106 via electromagnetic telemetry system 150. For example, during LWD and MWD drilling operations, well logging
15 component 124 may communicate information via electromagnetic telemetry system 150 relating to drilling equipment, downhole conditions, and/or the surrounding formation to well surface 106. The information from well logging component 124 may be used to inform the drilling operator of various downhole conditions in order to assist in the completion of the drilling operations. For example, well logging
20 component 124 may detect changes in the formation as drill bit 101 progresses through formation 130, indicating that the bit is at or near a region of the formation containing natural resources desired for extraction. Similarly, well logging component 124 may monitor conditions of the downhole equipment to, for example, inform the well operator that it is time to replace drill bit 101.

25 Information from downhole components may be encoded into an analog signal for transmission by electromagnetic telemetry system 150. For example, well logging component 124 may include electronics to encode measurements or other information from various downhole sensors into an analog signal. As an example and not by way of limitation, measurements or other information from the downhole components may
30 be encoded into the signal using amplitude modulation, phase modulation, pulse position modulation, orthogonal frequency modulation, and/or frequency modulation.

In some embodiments, transmitter 152 and/or other downhole components coupled to transmitter 152 may include electronics to encode information into an analog signal for transmission uphole.

Transmitter 152 may generate alternating current that represents the encoded
5 analog signal to be communicated from the downhole component to well surface 106 along the electrically conductive member (e.g., drill string 103). Transmitter 152 may include any device capable of generating or inducing a current along drill string 103. In some embodiments, transmitter 152 may be a gap sub assembly including an electrically insulating material, such as ceramic or plastic, placed between two regions
10 of drill string 103 that creates an insulating gap to electrically isolate the two regions. When an electric potential (e.g., a voltage) is applied across the two electrically isolated regions, current 158 may begin to flow along drill string 103 in an amount that is proportional to the electric potential applied. In other embodiments, transmitter 152 may be a toroid placed around drill string 103 that includes a winding of wire
15 wrapped around a ring-shaped magnetic core. When an alternating current is applied to the winding of wire, a magnetic flux in the core of the toroid is produced that may induce current 158 to flow along drill string 103. Transmitter 152 may be selected and/or designed to withstand the harsh conditions present in wellbore 114 and the electric potential applied by components communicating with electromagnetic
20 telemetry system 150. Transmitter 152 may be electrically coupled to a power source, such as an electrical supply grid, generator, battery, fuel cell, solar cell, and/or another suitable device configured to generate energy sufficient to create a current along the electrically conductive member.

The encoded analog signal from transmitter 152 may travel to well surface 106
25 in the form of electromagnetic waves created by current 158 and be detectable by one or more receivers 154. Receiver 154 may be any device capable of detecting the analog signal from transmitter 152. For example, receiver 154 may include an electric dipole antenna as shown in receivers 154a and 154b. Receiver 154 may further include a differential amplifier that amplifies the difference of electric potential
30 measured by the electric dipole antenna. In some embodiments, receiver 154 may include an electro-optical transducer coupled to a fiber optic cable placed along the

ground above formation 130. The electro-optical transducer may change shape in response to the difference of electric potential applied to the fiber optic cable. An optical interrogation (not expressly shown) may measure the difference of electric potential applied to the electro-optical transducer by detecting changes in light on the optical fiber coupled to the electro-optical transducer. In other embodiments, receiver 154 may include a magnetometer that detects magnetic fields and/or magnetic induction caused by current 158. The magnetometer may be placed generally orthogonal to the projection of wellbore 114 or parallel to the ground at or near well surface 106. In certain embodiments, receiver 154 may include a combination of elements disclosed herein. In some embodiments, different receivers may include different elements for detecting signals from transmitter 152. Receiver 154 may be selected and/or configured based on size, cost, signal reception, or other factors.

As shown in FIGURE 1, receiver 154a may include an electric dipole antenna electrically coupled to drill string 103 at well surface 106 and a grounding stake placed in formation 130 away from drilling rig 102. The flow of current 158 along drill string 103 may create an electric potential between drill string 103 and the grounding stake that varies with current 158. The electric dipole antenna in receiver 154 may detect the electric potential between drill string 103 and the grounding stake corresponding to the encoded analog signal from transmitter 152. In some embodiments, the difference in electric potential across the electric dipole antenna may be amplified by a differential amplifier in receiver 154a.

Receiver processing system 160 may communicatively couple to receiver 154a in order to store and/or process the encoded analog signal communicated from transmitter 152. For example, receiver processing system 160 may receive the signal from receiver 154a through a physical transmission medium (e.g., a wire or cable), or through wireless communication technology such as Wi-Fi or Bluetooth. Receiver processing system 160 may include a computer with a central processing unit, memory, and/or a display. The well operator and/or engineers may interact with receiver processing system 160 through a user interface on the display and input devices such as keyboards, pointer devices, and touchscreens, and via output devices such as printers, monitors, and touchscreens. Software running on receiver processing

system 160 may reside in the memory and/or on non-transient information storage media coupled the system. Receiver processing system 160 may be implemented in different forms including, for example, an embedded computer permanently installed as part of a larger control system managing well operations, a portable computer, a
5 mobile device, multiple computers coupled by a network, and/or any electronic device having a programmable processor and an interface for input and output.

Receiver processing system 160 may contain software instructions to decode the analog signal received by receiver 154a to determine the information transmitted by transmitter 152. For example, receiver processing system 160 may decode the
10 analog signal sent from transmitter 152 to determine the information sent from well logging tool 124. Therefore, receiver processing system 160 may be able to determine, for example, measurements made by well logging component 124 downhole within wellbore 114. Receiver processing system 160 may also contain software instructions to perform various other tasks, such as signal processing,
15 calculating parameters based on one or more signals received, enhancing well production, managing drilling operations, and/or controlling intelligent well completions. For example, as disclosed below with respect to FIGURE 3, receiver processing system 160 may determine location data for transmitter 152 by comparing and/or processing the signals at receivers 154.

20 A signal from transmitter 152 will attenuate as it travels to receiver 154. For example, as the distance between transmitter 152 and receiver 154 increases, the strength of the signal at receiver 154 may lessen. Electromagnetic telemetry system 150 may also be susceptible to noise. For example, in addition to the desired signal from transmitter 152, receiver 154 may detect electromagnetic waves generated by
25 elements external to electromagnetic telemetry system 150 and/or components of the telemetry system. Improving the magnitude of the desired signal from transmitter 152 and decreasing the magnitude of noise may be desirable to improve the overall signal transmission capabilities of electromagnetic telemetry system 150.

As discussed in more detail with respect to FIGURE 2, the signal transmission
30 of electromagnetic telemetry system 150 may be improved by combining the signal received at receiver 154a with the signal received at another receiver 154b. The

magnitude of the combined signal may be greater than that of the signals at the individual receivers 154. Moreover, the magnitude of the noise in the combined signal may be reduced as some of the noise at the two receivers may cancel each other out when the signals from the receivers are combined. Therefore, combining the signal at receiver 154a with the signal at receiver 154b may improve the overall signal transmission capabilities of electromagnetic telemetry system 150.

Receiver 154b may be placed apart from 154a at well surface 106, above or near the non-vertical portions of the wellbore, such as generally horizontal wellbore 114b. During signal transmission, some of current 158 traveling along drill string 103 will leak or migrate into formation 130 resulting in a signal loss or attenuation. That is, less signal may be received at receiver 154 than was generated downhole by transmitter 152. The amount of current leaking into formation 130 may vary based on the conductivity of formation 130, the conductivity of the electrically conductive member (e.g., drill string 103), the distance of transmitter 152 from well surface 106, downhole fluids within the wellbore, and/or other elements present in and around wellbore 114. Receiver 154b may increase the overall signal reception of the electromagnetic telemetry system 150 by, for example, detecting electromagnetic waves created by the current that has leaked into formation 130.

Receiver 154b may include an electric dipole antenna electrically coupling two grounding stakes placed in formation 130 at a distance (e.g., 50 meters) from each other. The flow of current in formation 130 at or near the grounding stakes, some of which may be current from transmitter 152 leaking into the formation, may result in a difference of electric potential between the grounding stakes. A differential amplifier in receiver 154b may amplify the difference of electric potential. Receiver processing system 160 may communicatively couple (e.g., through a physical transmission medium or wireless communication technology) to receiver 154b in order to store and/or process the signals received by receivers 154. Among other things, receiver processing system 160 may combine the signals from receiver 154a and receiver 154b as discussed in reference to FIGURES 2A and 2B, or determine location data for transmitter 152 as discussed in reference to FIGURE 3.

The placement of receiver 154b may be selected based on a variety of factors.

For example, receiver 154b may be placed in a location so to maximize the total signal received from transmitter 152. As an example, the highest combined signal from receivers 154a and 154b may occur when receiver 154b is placed parallel to wellbore 114 at a location approximately above the location of transmitter 152.

5 Analytical calculations may be conducted with modeling software to determine where the highest combined signal from receivers 154a and 154b is likely to occur based on, for example, the location of transmitter 152, the properties of formation 130, and/or the direction and depth of wellbore 114. Additionally, field measurements may be conducted on various placements of receiver 154b to determine which location results

10 in the highest combined signal from receivers 154a and 154b. For example, 154b may be moved to various locations to determine which location results in the highest combined signal. In some embodiments, the placement of receiver 154b may be selected to limit the amount of noise at receiver 154b while still detecting signals from transmitter 152. For example, placing receiver 154b further from vertical portions of

15 the wellbore, such as generally vertical wellbore 114a, may reduce the amount of unintended noise at receiver 154b while not necessarily increasing the distance between transmitter 152 and receiver 154b. Reducing noise at receiver 154b may improve the signal-to-noise ratio (e.g., the strength of the desired signal relative to the undesirable noise) of electromagnetic telemetry system 150. In some embodiments,

20 placement of receiver 154b may be selected based on the intended path or current location of transmitter 152. For example, receiver 154b may be moved along an intended drilling path to maintain close proximity to transmitter 152 coupled to drill string 103 as the drilling operations progress.

Receiver processing system 160 may combine the signals received by receiver

25 154a and receiver 154b to increase the overall signal reception of electromagnetic telemetry system 150. For example, the signal at receiver 154a may be combined with the signal at receiver 154b to create a combined signal that is greater in strength or magnitude than the signals received at the individual receivers. To maximize the combined signal and reduce signal cancelation, receiver processing system 160 may

30 account for phase shifting of the signals received at receivers 154a and 154b. The benefits and methods of combining signals from two or more receivers are best

illustrated by considering the combination of signals received at two receivers, such as receivers 154a and 154b.

FIGURE 2A is a graph including plots of exemplary signals received by an electromagnetic telemetry system with two receivers. Specifically, signal 202 may represent an analog signal received at a receiver placed at or near the well surface, such as receiver 154a disclosed with respect to FIGURE 1. Signal 202 may contain a maximum amplitude variation 204. Signal 206 may represent an analog signal received at a second receiver located further from well surface but closer to the transmitter of the electromagnetic telemetry system, such as receiver 154b disclosed with respect to FIGURE 1. Signal 206 may contain a maximum amplitude variation 208. Maximum amplitude variations 204 and 208 may represent the strength of the analog signal from the transmitter of the electromagnetic telemetry system as received at the respective receivers. Maximum amplitude variations 204 and 208 may be affected by, for example, the portion of the signal from the transmitter leaking into the formation, the distance of the receiver from the transmitter, and/or the conductivity of the electrically conductive member.

Portions of signals 202 and 206 may contain undesirable noise in the electromagnetic telemetry system. The noise in signal 202 may be represented by noise amplitude variations 212, and the noise in signal 206 may be represented by noise amplitude variations 214. As discussed above, noise may be caused by a variety of factors, including, for example, electromagnetic waves created by elements external to the electromagnetic telemetry system and/or components of the electromagnetic telemetry system. The ability of the electromagnetic telemetry system to reliably communicate information may depend on the ratio of desired signal from the transmitter to the undesirable noise, or the signal-to-noise ratio of the system. Therefore, combining signals 202 and 206 may improve the signal-to-noise ratio by creating a stronger combined signal representing the desired signal from the transmitter.

However, as illustrated in FIGURE 2A, signals 202 and 206 may be out of phase with each other by phase 216. Signals 202 and 206 may be out of phase based on a variety of reasons including, for example, the amount of time it takes the

electromagnetic waves from the transmitter to reach each receiver. The travel time for the electromagnetic waves from the transmitter to the individual receivers may depend on the distance between the receiver and the transmitter, the conductivity of the medium through which the waves travel, the frequency of the signal, the strength
5 of the signal, and/or other factors. Accordingly, the same signal from the transmitter may arrive at different receivers at different times, resulting in the signals being out of phase with each other by phase 216.

Summing signals 202 and 206 without accounting for phase 216 may result in partial cancellation of the signals, or degradation of the communication efficiency of the electromagnetic telemetry system. For example, combining out-of-phase signals
10 may result in a combined signal that no longer resembles the transmitted signal. Therefore, summing the signals without accounting for phase 216 may result in a combined signal that may no longer be decoded to determine the information transmitted from the transmitter. Accordingly, the system processing the signals from
15 the receivers, such as receiver processing system 160 disclosed in FIGURE 1, may calculate phase 216 by comparing signals 202 and 206, and apply an appropriate phase shift to align signals 202 and 206. For example, signal 202 or signal 206 may be shifted by phase 216 to align the signals. After the appropriate phase shifting has occurred, signals 202 and 206 may be summed together to create a stronger combined
20 signal representing the signal from the transmitter of the electromagnetic telemetry system.

FIGURE 2B is a graph including a plot of an exemplary combined signal of an electromagnetic telemetry system. Combined signal 220 may represent a summation of signal 202 and 206 from the two receivers after phase shifting has been accounted
25 for. Maximum amplitude variations 222 may represent the approximate sum of maximum amplitude variations 204 and 208 from signals 202 and 206 respectively, and the maximum amplitude of the sum of signal 202 with a phase shifted version of signal 206, where the phase shift operation is carried out so as to maximize the signal-to-noise ratio of the electromagnetic telemetry system. A portion of combined signal
30 220 may be undesirable noise represented by noise amplitude variations 224.

In addition to increasing the combined signal strength, combining the signals

from two receivers placed at different locations may result in noise cancelation, or a decrease in the magnitude of the noise. Increasing the combined signal while lowering the noise may result in a higher signal-to-noise ratio in the electromagnetic telemetry system. Noise at the first receiver and noise at the second receiver, represented by
5 noise amplitude variations 212 and noise 214 in FIGURE 2A, may be caused by different sources at or near the respective receivers. For example, the receiver at or near the drilling rig may experience noise from elements within the wellbore, such as drilling, production, and monitoring equipment and electronics. Further from the drilling rig, noise sources affecting the second receiver may be primarily above-
10 ground elements, such as well completion equipment operating above a reservoir. Additionally, noise signals at the receivers from common noise sources may be out of phase and/or at different strengths (e.g., amplitude) at each receiver. Thus, the resulting combined noise at the individual receivers may vary in frequency, phase, and/or amplitude. Because the noise signals may not align, portions of the noise
15 signals may offset or cancel each other out when signal 202 is combined with signal 206. Therefore, the amount of undesirable noise in signal 220, represented by noise amplitude variations 224, may be smaller than noise amplitude variations 212 and 214 or the combination thereof. At the same time, the magnitude of combined signal 220, represented by maximum amplitude variation 222 may have increased relative to
20 signals 202 and 206 at the individual receivers. Therefore, combining signals from the two receivers may result in a higher signal-to-noise ratio for the electromagnetic telemetry system compared to using a single receiver. The same principles may apply for additional receivers added to the electromagnetic telemetry system.

In some circumstances, the transmitter of an electromagnetic telemetry system
25 may change locations within the wellbore as the electrically conductive member to which it is coupled moves. For example, as a drill string forms new regions of a wellbore, a transmitter located at or near the end of the drill string may move. It may be desirable to track the location of the transmitter. In directional drilling for example, the location of the transmitter may also be indicative of the location of the drill bit.
30 Thus, tracking the location of the transmitter may, among other things, assist the drilling operator in determining whether the drill bit is following an intended drilling

path. Locating the position of a transmitter may serve purposes beyond drilling operations, such as, for example, monitoring the progress during insertion of a production tubing into a completed wellbore.

In addition to improving the signal reception of the electromagnetic telemetry system, multiple receivers may also provide location data for the transmitter based on the strength and/or phase (e.g., arrival time) of the signals at the different receivers. FIGURE 3 is an isometric view of an exemplary electromagnetic telemetry system including an array of receivers associated with a well system. The array of receivers may be placed in a matrix above formation 130, forming rows 304 and columns 302 of receivers 154. The array of receivers may be placed along the ground, in the ground, above the ground, or in any other manner that permits receivers 154 to detect signals from transmitter 152. Rows 304 and columns 302 may be aligned parallel and orthogonal to non-vertical portions of wellbore 114. Although receivers 154 are shown in a matrix of rows and columns, the array of receivers 154 may be placed in any arrangement or at any location above formation 130. As discussed below, wellbore 114 may change horizontal projection (e.g., the projection made on a plane parallel to the horizon) and/or vertical depth. In some embodiments, placement of the array of receivers 154 may be selected and/or changed based on the actual or anticipated path of the wellbore to, for example, maintain receivers 154 parallel and orthogonal to wellbore 114, or otherwise maintain receivers 154 in receiving proximity to transmitter 152.

As described in reference to FIGURE 1, electromagnetic telemetry system 150 may be used to communicate information from downhole components to receivers 154 at or near well surface 106. Each receiver 154 may receive the encoded analog signal generated by transmitter 152. Receivers 154 may be communicatively coupled to receiver processing system 160 through a physical transmission medium (e.g., a wire or cable), or through wireless communication technology such as Wi-Fi or Bluetooth. Receiver processing system 160 may combine the signals received by each receiver 154 according to the techniques disclosed with respect to FIGURE 2. Additionally, receiver processing system 160 may determine location data for transmitter 152 based on the strength and/or phase of the signals received at receivers

154.

As illustrated, wellbore 114 may change horizontal projection and/or depth at different locations. Transmitter 152, by its placement at BHA 120 of drill string 103, may move through each portion of wellbore 114 as drilling progresses and wellbore 114 is formed. Receiver processing system 160 may determine movement or location data of transmitter 152, and thereby drill bit 101 within the wellbore. For example, as transmitter 152 moves through generally horizontal wellbore 114b, the relative strength of the signals received at receivers 154 located in columns 302a and 302b may increase as transmitter 152 progresses closer and decrease as transmitter 152 moves past on the X-axis. In each column 302, the signal from transmitter 152 may be strongest along row 304b, the row of receivers 154 placed directly above wellbore 114b, and weakest at row 304d, the row of receivers 154 furthest from wellbore 114b on the Z-axis. Similarly, as transmitter 152 progresses through wellbore 114e moving on the Z-axis, the strength of the signal from transmitter 152 received at receivers 154 in column 302e may increase as transmitter 152 moves closer and decrease as transmitter 152 moves past. Thus, by measuring the relative signal strength from transmitter 152 received at each receiver 154, receiver processing system 160 may detect changes in the location of the generally horizontal wellbores 114b, 114d, and 114e.

Receiver processing system 160 may also detect depth changes of transmitter 152. For example, wellbore 114c may represent a change in depth of wellbore 114, or a portion of the wellbore that is closer to well surface 106 compared to neighboring wellbores 114b and 114d. When transmitter 152 passes through wellbore 114c, the distance between transmitter 152 and each receiver 154 may decrease, and therefore each receiver 154 may experience an increase in the signal strength from transmitter 152. The relative increase in signal strength at receivers 154 may indicate a change in depth of transmitter 152 as the transmitter moves closer to the surface (e.g., the vertical depth of transmitter 152 decreases). Thus, by measuring the signal strength received at each receiver 154, receiver processing system 160 may detect changes in the depth of transmitter 152.

Similar to the strength of the signal arriving at receiver 154, receiver

processing system 160 may also determine location data based on the phase of the signal at different receivers. For example, the longer a signal takes to arrive at receiver 154 from transmitter 152, the further the receiver may be from transmitter 152. Receiver processing system 160 may compare the signals at various receivers
5 154 in order to determine a relative difference in the time it takes each receiver 154 to receive the same signal. The relative arrival time of a signal at a particular receiver 154 may correspond to the phase of the signal, such that a later-arriving signal may be phase shifted later in time. Receiver processing system 160 may determine that transmitter 152 is located closer to certain receivers 154 compared to others based on
10 the phase differences of the signals received at the different receivers.

More accurate location data for transmitter 152 may be determined with additional information about formation 130 and/or wellbore 114. For example, formation 130 may vary in composition, affecting the flow of current and propagation of electromagnetic waves through formation 130. As a result, the accuracy of location
15 data determined based on the strength and/or phase of the signals received at receivers 154 may decrease in non-homogenous formations. Electromagnetic properties of formation 130 may be measured, collected, processed, and/or calculated from downhole components within wellbore 114, components located at well surface 106, components located in other wellbores at or near formation 130, as well as data
20 processing systems communicatively coupled to such components, such as receiver processing system 160. As an example, well logging component 124 may measure the conductivity of formation 130 as it moves within wellbore 114. Receiver processing system 160 may compile and/or process measurements from well logging component 124 to create a three-dimensional model of the conductivity of formation 130.
25 Modeling software may use the conductivity model of formation 130 to create a model of an electromagnetic telemetry system within wellbore 114. This model may be used to determine an expected phase and/or strength of a signal from transmitter 152 at a particular receiver 154. Additionally, the model of the electromagnetic telemetry system may be inverted to approximate the location of transmitter 152
30 based on the phase and/or strength of a signal actually received at one or more receivers 154. Thus, additional data about formation 130 and/or wellbore 114 may be

used to increase the accuracy of the location data calculated for transmitter 152, especially in a non-homogenous formation.

The number and placement of receivers 154 may affect the precision of the location data calculated. As an example, increasing the number of receivers 154 above
5 the formation near where transmitter 152 is located may allow for more precise location data as the number of measurement points increase. Therefore, although receivers 154 are placed in a grid format as shown in FIGURE 3, electromagnetic telemetry systems incorporating teachings of the present disclosure may be satisfactorily used with fewer or more receivers 154, and/or different placement of
10 receivers 154 than that illustrated.

Embodiments disclosed herein include:

A. An electromagnetic telemetry system that includes an electrically conductive member, a transmitter coupled to the electrically conductive member, the transmitter configured to induce an alternating current along the electrically
15 conductive member, the alternating current representing encoded information, a first receiver coupled to the electrically conductive member, the first receiver configured to receive electromagnetic waves resulting from the alternating current, a second receiver positioned at a location apart from the first receiver, the second receiver configured to receive the electromagnetic waves resulting from the alternating
20 current, and a receiver processing system communicatively coupled to the first receiver and the second receiver, the receiver processing system configured to process the electromagnetic waves received by the first receiver and the second receiver into a combined signal, and decode the combined signal.

B. A method for performing electromagnetic telemetry in a well system that
25 includes transmitting, by a transmitter, an alternating current along an electrically conductive member, the alternating current representing encoded information, receiving, at a first receiver coupled to the electrically conductive member, electromagnetic waves resulting from the alternating current, receiving, at a second receiver positioned at a location apart from the first receiver, the electromagnetic
30 waves resulting from the alternating current, generating a combined signal by combining the electromagnetic waves received by the first receiver and the second

receiver, and decoding the combined signal.

C. An electromagnetic telemetry system that includes an electrically conductive member, a transmitter coupled to the electrically conductive member, the transmitter configured to induce an alternating current along the electrically
5 conductive member, an array of receivers configured to receive electromagnetic waves resulting from the alternating current, a receiver processing system communicatively coupled to the array of receivers, the receiver processing system configured to determine an approximate location of the transmitter based on the electromagnetic waves received by the array of receivers.

10 D. A method for determining an approximate location of a transmitter that includes transmitting, by the transmitter, an alternating current along an electrically conductive member within a wellbore including a non-vertical portion within a formation, receiving electromagnetic waves resulting from the alternating current at an array of receivers located at a surface above the formation, and determining an
15 approximate location of the transmitter within the wellbore based on the electromagnetic waves received by the array of receivers.

Each of embodiments A, B, C, and D may have one or more of the following additional elements in any combination: Element 1: wherein at least one of the first receiver and the second receiver is an electric dipole antenna. Element 2: wherein at
20 least one of the first receiver and the second receiver is a magnetometer. Element 3: wherein processing the electromagnetic waves received by the first receiver and the second receiver comprises phase shifting the electromagnetic waves received by the second receiver. Element 4: wherein the receiver processing system is further configured to determine an approximate location of the transmitter within a wellbore
25 based on a strength of the electromagnetic waves received by at least one of the first receiver and the second receiver. Element 5: wherein the receiver processing system is further configured to determine an approximate location of the transmitter within a wellbore based on a phase of the electromagnetic waves received by at least one of the first receiver and the second receiver. Element 6: wherein the electrically
30 conductive member is a drill string, a casing string, or a production tubing. Element 7: wherein the electrically conductive member is positioned within a wellbore

including a non-vertical portion and the transmitter is positioned within the non-vertical portion of the wellbore. Element 8: further comprising changing the location of the second receiver as the transmitter moves to increase a strength of the electromagnetic waves at the second receiver. Element 9: wherein the approximate
5 location of the transmitter is determined by a strength of the electromagnetic waves received by the array of receivers. Element 10: wherein the approximate location of the transmitter within the wellbore is determined by a phase of the electromagnetic waves received by the array of receivers. Element 11: wherein the array of receivers are arranged in rows and columns at a surface above a formation surrounding a
10 wellbore. Element 12: wherein the rows are oriented approximately parallel to a non-vertical portion of the wellbore. Element 13: wherein the receiver processing system is further configured to determine the approximate location of the transmitter based on an electromagnetic property of a formation surrounding the electrically conductive member. Element 14: further comprising moving the array of receivers closer to the
15 transmitter as the transmitter moves within the wellbore.

Although the present disclosure and its advantages have been described in detail, it should be understood that various changes, substitutions and alterations can be made herein without departing from the spirit and scope of the disclosure as defined by the following claims. For example, in addition to a drill string, the
20 electrically conductive member within the wellbore may be any other electrically conductive element extending from a location downhole to uphole, including for example, a casing string or production tubing.

WHAT IS CLAIMED IS:

1. An electromagnetic telemetry system, comprising:
an electrically conductive member;
a transmitter coupled to the electrically conductive member, the transmitter
5 configured to induce an alternating current along the electrically conductive member,
the alternating current representing encoded information;
a first receiver coupled to the electrically conductive member, the first receiver
configured to receive electromagnetic waves resulting from the alternating current;
a second receiver positioned at a location apart from the first receiver, the
10 second receiver configured to receive the electromagnetic waves resulting from the
alternating current; and
a receiver processing system communicatively coupled to the first receiver and
the second receiver, the receiver processing system configured to:
process the electromagnetic waves received by the first receiver and
15 the second receiver into a combined signal; and
decode the combined signal.
2. The system of claim 1, wherein at least one of the first receiver and the
second receiver is an electric dipole antenna.
20
3. The system of claim 1, wherein at least one of the first receiver and the
second receiver is a magnetometer.
4. The system of claim 1, wherein processing the electromagnetic waves
25 received by the first receiver and the second receiver comprises phase shifting the
electromagnetic waves received by the second receiver.
5. The system of claim 1, wherein the receiver processing system is
further configured to determine an approximate location of the transmitter within a
30 wellbore based on a strength of the electromagnetic waves received by at least one of
the first receiver and the second receiver.

6. The system of claim 1, wherein the receiver processing system is further configured to determine an approximate location of the transmitter within a wellbore based on a phase of the electromagnetic waves received by at least one of the first receiver and the second receiver.

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7. The system of claim 1, wherein the electrically conductive member is a drill string, a casing string, or a production tubing.

8. The system of claim 1, wherein the electrically conductive member is positioned within a wellbore including a non-vertical portion and the transmitter is positioned within the non-vertical portion of the wellbore.

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9. A method for performing electromagnetic telemetry in a well system, the method comprising:

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transmitting, by a transmitter, an alternating current along an electrically conductive member, the alternating current representing encoded information;

receiving, at a first receiver coupled to the electrically conductive member, electromagnetic waves resulting from the alternating current;

receiving, at a second receiver positioned at a location apart from the first receiver, the electromagnetic waves resulting from the alternating current;

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generating a combined signal by combining the electromagnetic waves received by the first receiver and the second receiver; and

decoding the combined signal.

10. The method of claim 9, wherein at least one of the first receiver and the second receiver is an electric dipole antenna.

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11. The method of claim 9, wherein at least one of the first receiver and the second receiver is a magnetometer.

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12. The method of claim 9, wherein generating the combined signal

comprises phase shifting the electromagnetic waves received by the second receiver.

13. The method of claim 9, further comprising changing the location of the second receiver as the transmitter moves to increase a strength of the electromagnetic waves at the second receiver.

14. The method of claim 9, further comprising determining an approximate location of the transmitter based on a strength of the electromagnetic waves received by at least one of the first receiver and the second receiver.

15. The method of claim 9, further comprising determining an approximate location of the transmitter based on a phase of the electromagnetic waves received by at least one of the first receiver and the second receiver.

16. The method of claim 9, wherein the electrically conductive member is a drill string, a casing string, or a production tubing.

17. The method of claim 9, wherein the electrically conductive member is positioned within a wellbore including a non-vertical portion.

18. An electromagnetic telemetry system, comprising:
an electrically conductive member;
a transmitter coupled to the electrically conductive member, the transmitter configured to induce an alternating current along the electrically conductive member;
an array of receivers configured to receive electromagnetic waves resulting from the alternating current;
a receiver processing system communicatively coupled to the array of receivers, the receiver processing system configured to determine an approximate location of the transmitter based on the electromagnetic waves received by the array of receivers.

19. The system of claim 18, wherein the approximate location of the transmitter is determined by a strength of the electromagnetic waves received by the array of receivers.

5 20. The system of claim 18, wherein the approximate location of the transmitter is determined by a phase of the electromagnetic waves received by the array of receivers.

21. The system of claim 18, wherein the array of receivers are arranged in
10 rows and columns at a surface above a formation surrounding a wellbore.

22. The system of claim 21, wherein the rows are oriented approximately parallel to a non-vertical portion of the wellbore.

15 23. The system of claim 18, wherein the receiver processing system is further configured to determine the approximate location of the transmitter based on an electromagnetic property of a formation surrounding the electrically conductive member.

20 24. The system of claim 18, wherein the electrically conductive member is positioned within a wellbore including a non-vertical portion and the transmitter is positioned within the non-vertical portion of the wellbore.

25 25. A method for determining an approximate location of a transmitter, the method comprising:

transmitting, by a transmitter, an alternating current along an electrically conductive member within a wellbore including a non-vertical portion within a formation;

30 receiving electromagnetic waves resulting from the alternating current at an array of receivers located at a surface above the formation; and

determining an approximate location of the transmitter within the wellbore

based on the electromagnetic waves received by the array of receivers.

26. The method of claim 25, wherein the approximate location of the transmitter within the wellbore is determined by a strength of the electromagnetic waves received by the array of receivers.

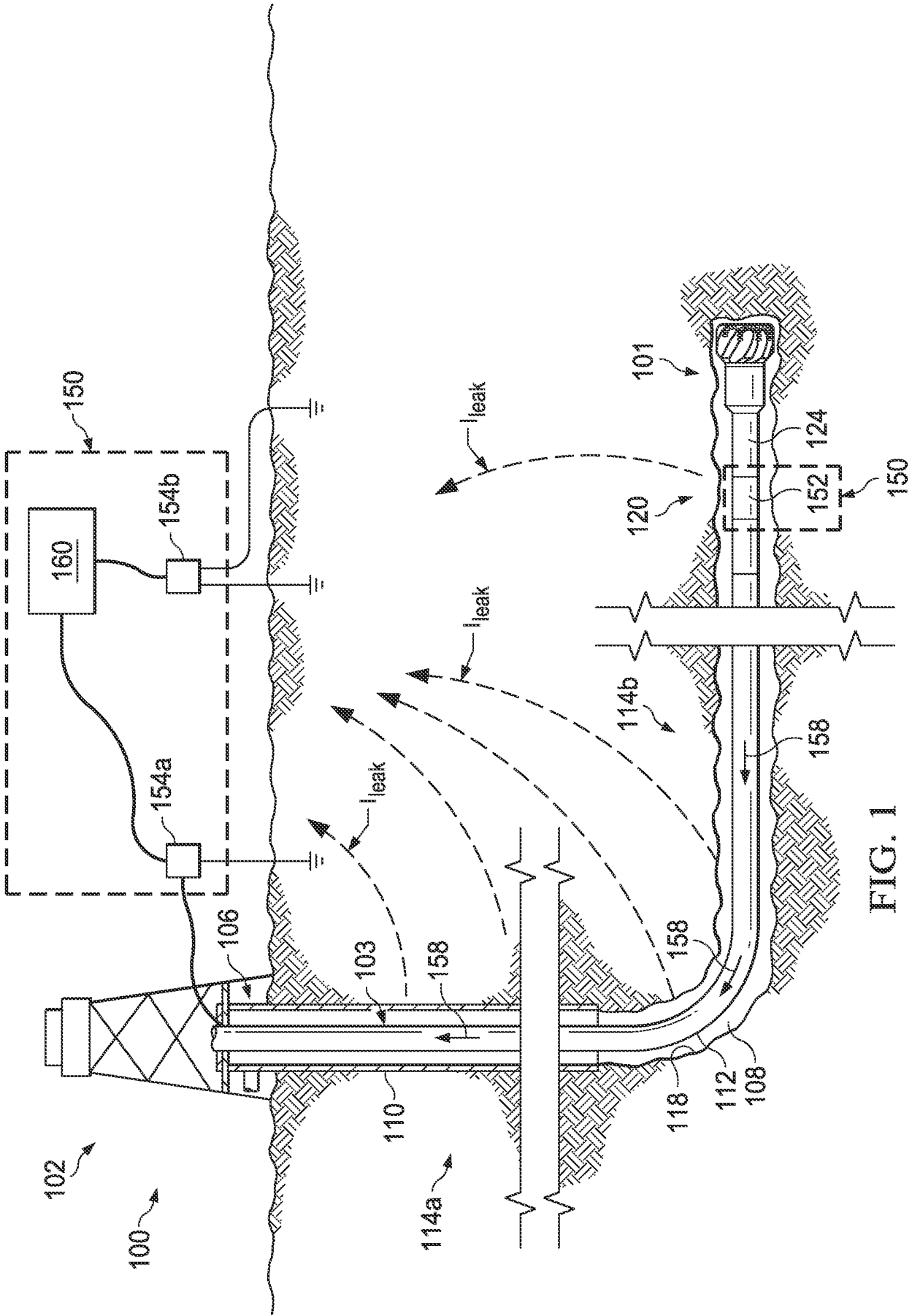
27. The method of claim 25, wherein the approximate location of the transmitter within the wellbore is determined by a phase of the electromagnetic waves received by the array of receivers.

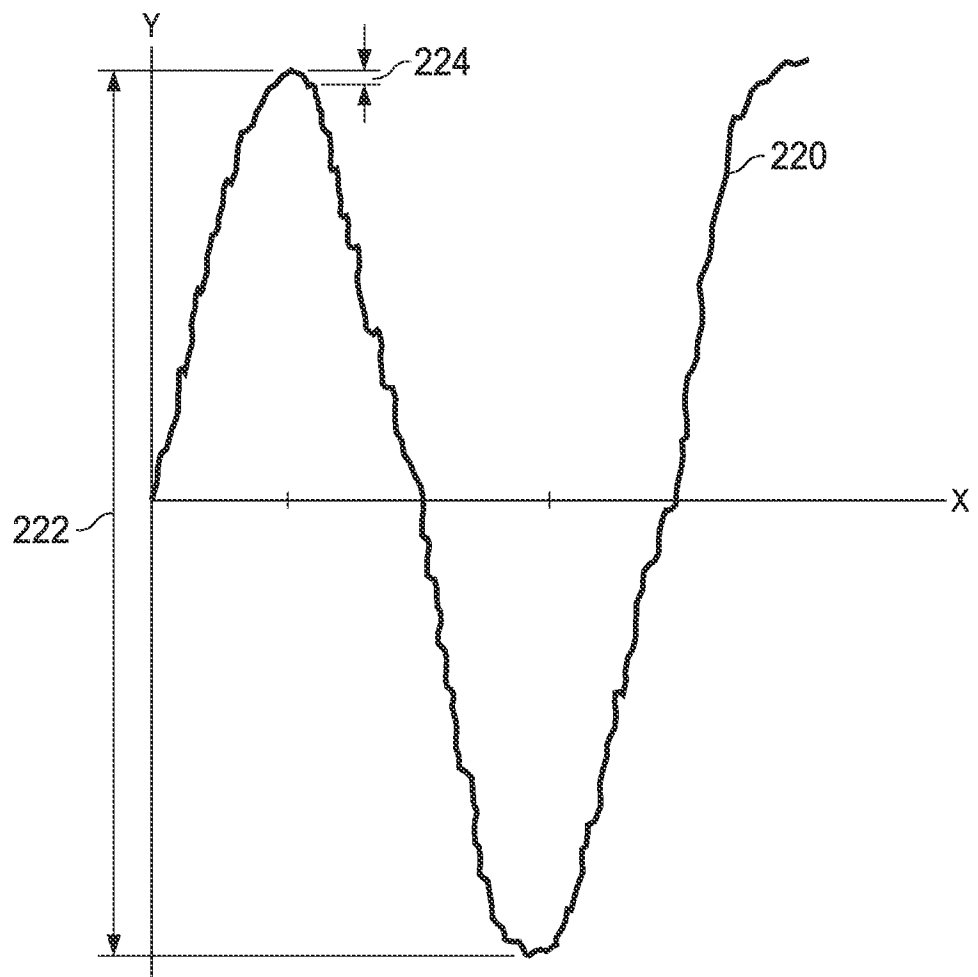
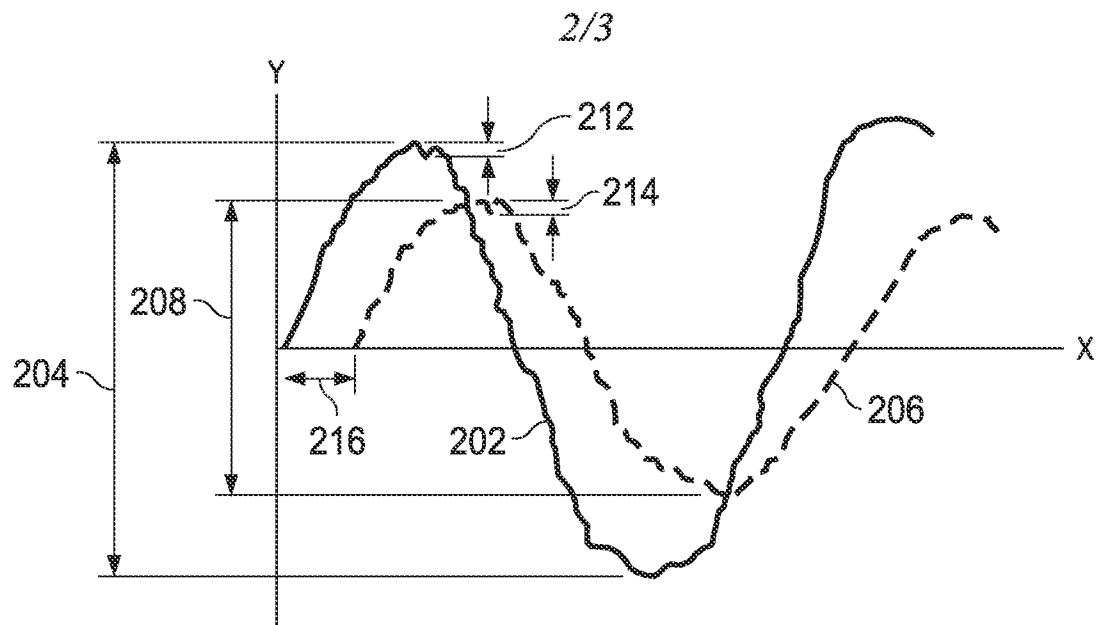
28. The method of claim 25, wherein the array of receivers are arranged in rows and columns.

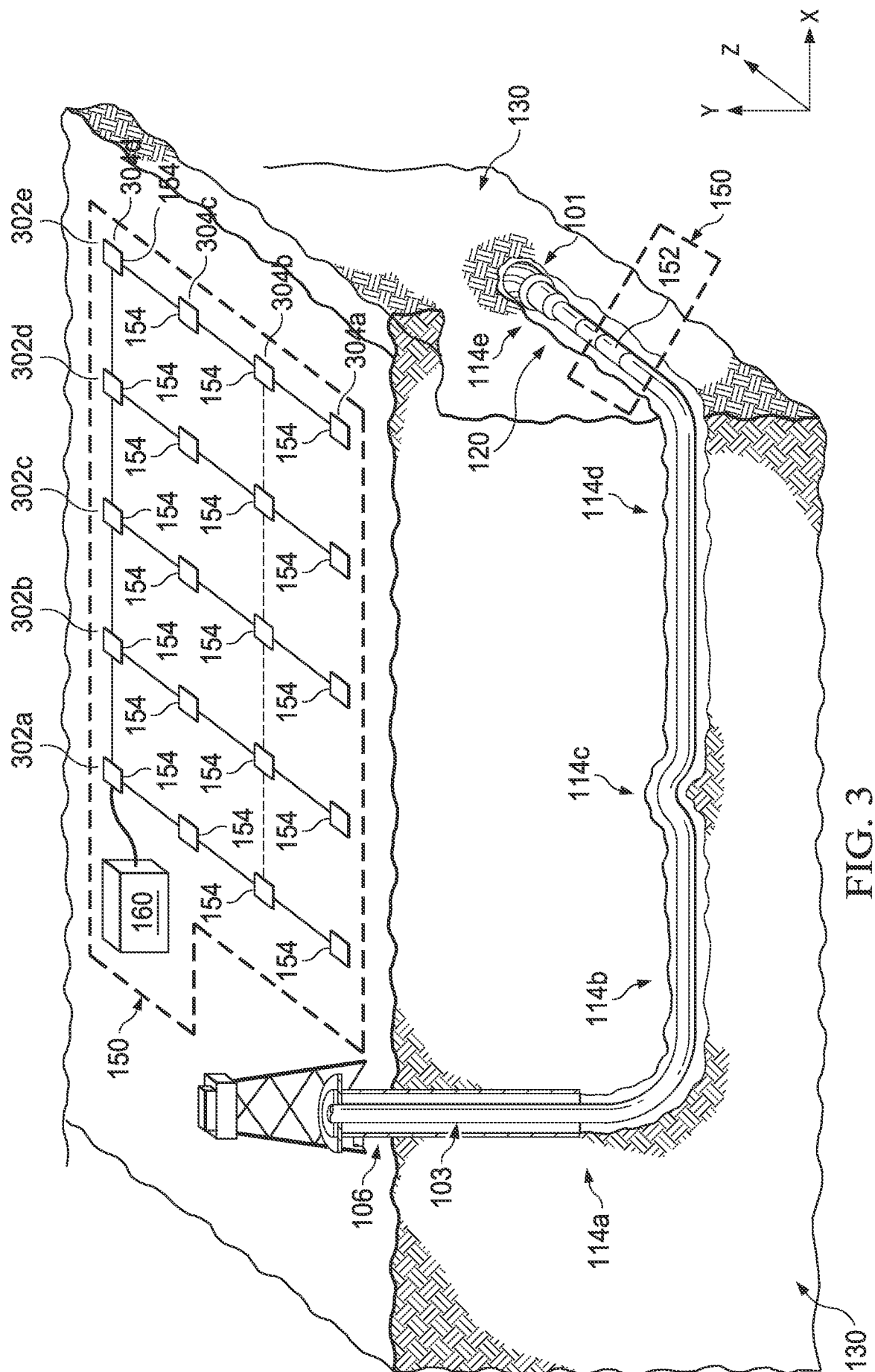
29. The method of claim 25, wherein the rows are oriented approximately parallel to the non-vertical portion of the wellbore.

30. The method of claim 25, further comprising moving the array of receivers closer to the transmitter as the transmitter moves within the wellbore.

31. The method of claim 25, wherein the receiver processing system is further configured to determine the approximate location of the transmitter based on an electromagnetic property of the formation.







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INTERNATIONAL SEARCH REPORT

International application No.
PCT/US2015/051699**A. CLASSIFICATION OF SUBJECT MATTER****E21B 47/12(2006.01)i, E21B 47/13(2012.01)i**

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

E21B 47/12; G01V 3/20; E21B 47/02; G01V 3/12; G01V 3/00; H01F 41/00; G01V 11/00; E21B 47/13

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Korean utility models and applications for utility models

Japanese utility models and applications for utility models

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

eKOMPASS(KIPO internal) & Keywords: electromagnetic, transmitter, receiver, alternating current, information, array, shift, non-vertical wellbore and telemetry

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2005-0183887 A1 (RODNEY, PAUL F.) 25 August 2005 See paragraphs [0019]-[0036]; claims 1, 11; and figures 1-3.	1-31
A	US 2015-0247401 A1 (APS TECHNOLOGY, INC.) 03 September 2015 See paragraphs [0019]-[0023]; claim 1; and figures 1A-1B.	1-31
A	US 2007-0247328 A1 (PETROVIC et al.) 25 October 2007 See claims 1-10 and figure 1.	1-31
A	US 6781520 B1 (SMITH et al.) 24 August 2004 See claim 1 and figure 1.	1-31
A	EP 2368141 B1 (SCHLUMBERGER TECHNOLOGY B.V. et al.) 13 February 2013 See claims 1-13 and figures 3-4.	1-31



Further documents are listed in the continuation of Box C.



See patent family annex.

* Special categories of cited documents:

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"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search

08 December 2015 (08.12.2015)

Date of mailing of the international search report

09 December 2015 (09.12.2015)

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INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2015/051699

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