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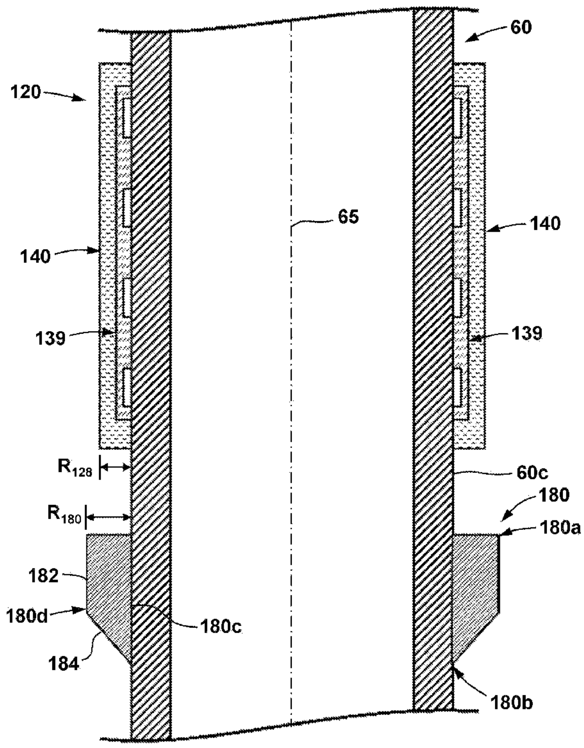

FIG. 7

(57) Abstract: A system includes a tubular member (60) including a radially outer surface (60c) and a sensor assembly (128). The sensor assembly includes a strain sensor coupled to the radially outer surface. In addition, the sensor assembly includes a first coating having (134) a first hardness and a first tensile strength. The first coating encases the strain sensor (131,130) and at least part (64) of the outer surface. Further, the sensor assembly includes a second coating (136) having a second hardness that is greater than the first hardness and a second tensile strength that is greater than the first tensile strength. The second coating encases the first coating and at least another part (68) of the radially outer surface.

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SYSTEMS AND METHODS FOR DETERMINING THE STRAIN EXPERIENCED BY WELLHEAD TUBULARS

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application claims benefit of U.S. provisional patent application Serial No. 62/149,096 filed April 17, 2015, and entitled “Systems and Methods for Determining the Strain Experienced by Wellhead Tubulars,” which is hereby incorporated herein by reference in its entirety for all purposes.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

[0002] Not applicable.

BACKGROUND

[0003] Embodiments disclosed herein relate generally to oil and gas wells. More particularly, embodiments disclosed herein relate to systems and methods for measuring the strain experienced by tubular members employed in oil and gas wells.

[0004] In drilling operations, a large diameter hole is drilled from the surface to a selected depth. Then, a primary conductor secured to the lower end of an outer wellhead housing disposed at the surface, also referred to as a low pressure housing, is run into the borehole. Cement is pumped down the primary conductor and allowed to flow back up the annulus between the primary conductor and the borehole sidewall. Alternatively, the primary conductor is jetted into place (i.e., no cement is used).

[0005] With the primary conductor secured in place, a drill bit is lowered through the primary conductor to drill the borehole to a second depth. Next, an inner wellhead housing, also referred to as a high pressure housing, is seated in the upper end of the outer wellhead housing. A string of casing secured to the lower end of the inner wellhead housing or seated in the inner wellhead housing extends downward through the primary conductor. Cement is pumped down the casing string, and allowed to flow back up the annulus between the casing string and the primary conductor to secure the casing string in place. The drill bit is lowered through the primary conductor and the casing string and drilling continues.

[0006] Prior to continuing drilling operations in greater depths, a blowout preventer (BOP) is mounted to the wellhead, and in subsea environments, a lower marine riser package (LMRP) is mounted to the BOP. The drill string is suspended from the rig through the BOP (and LMPR in offshore operations) into the well bore. Drilling generally continues while successively installing concentric casing strings that line the borehole. Each casing string is cemented in place by pumping cement down the casing and allowing it to flow back up the annulus between the casing string and the borehole sidewall.

[0007] Following drilling operations, the cased well is completed (i.e., prepared for production). Typically, a production tree is installed on the wellhead during completion operations and production tubing is run through the casing and suspended by a tubing hanger seated in a mating profile in the inner wellhead housing or production tree.

[0008] During drilling and production operations, the main function of the primary conductor is to resist axial and lateral loads imposed at the wellhead. Such loads can be particularly large in offshore operations where a relatively large, heavy stack of equipment (e.g., production tree, BOP, LMRP) is mounted atop the wellhead and is subjected to subsea currents. As a result, the primary conductor typically experiences a significant amount of strain. In extreme scenarios, the strain may be sufficient to damage the primary conductor (either through fatigue or some other failure modality).

BRIEF SUMMARY OF THE DISCLOSURE

[0009] Some embodiments disclosed herein are directed to a conductor for use in oil and gas wells. In an embodiment, the conductor includes a tubular member with a radially outer surface, and a sensor assembly. The sensor assembly includes a strain sensor coupled to the outer surface. In addition, the sensor assembly includes a first coating having a first hardness and a first tensile strength and encasing the sensor and at least part of the outer surface. Further, the sensor assembly includes a second coating having a second hardness that is greater than the first hardness, a second tensile strength that is greater than the first tensile strength. The second coating encases the first coating and at least another part of the outer surface.

[0010] Other embodiments disclosed herein are directed to a system. In an embodiment, the system includes a wellhead and a tubular member configured to be coupled to the wellhead and to extend into a wellbore. The tubular member has a radially outer surface. In addition, the system includes a first strain sensor coupled to the radially outer surface and an outer coating disposed over the first strain sensor. Further, the system includes a communication unit in communication with the first strain sensor and a remote surface location.

[0011] Other embodiments disclosed herein are directed to a method for manufacturing a conductor for use in an oil and gas well. In an embodiment, the method includes (a) coupling a first strain sensor to a radially outer surface of the conductor. The first strain sensor is configured to measure the strain on outer surface. In addition, the method includes (b) encasing the first sensor with a first coating having a first hardness and a first tensile strength after (a). Further, the method includes (c) encasing the first coating with a second coating after (b). The second coating has a second hardness that is greater than the first hardness and a second tensile strength that is greater than the first tensile strength.

[0012] Other embodiments disclosed herein are directed to a method of measuring strain on a first conductor for use in an oil and gas well. In an embodiment, the method includes (a) measuring a strain on the first conductor with a first strain sensor coupled to a radially outer surface of the first conductor. In addition, the method includes (b) protecting the first strain sensor during (a) with an outer coating. Further, the method includes (c) routing data from the first strain sensor to a communication unit after (a). Still further, the method includes (d) wirelessly communicating with a remote surface location with the communication unit after (c).

[0013] Still other embodiments disclosed herein are directed to a system. In an embodiment, the system includes a tubular member including a radially outer surface. In addition, the system includes a sensor assembly. The sensor assembly includes a strain sensor coupled to the radially outer surface of the tubular member. In addition, the sensor assembly includes a first coating having a first hardness and a first tensile strength. The first coating encases the strain sensor and at least part of the radially outer surface of the tubular member. Further, the system includes a second coating having a second hardness that is greater than the first hardness and a second tensile strength that is greater than the first tensile strength. The second coating encases the first coating and at least another part of the radially outer surface.

[0014] Embodiments described herein comprise a combination of features and advantages intended to address various shortcomings associated with certain prior devices, systems, and methods. The foregoing has outlined rather broadly the features and technical advantages of the invention in order that the detailed description of the invention that follows may be better understood. The various characteristics described above, as well as other features, will be readily apparent to those skilled in the art upon reading the following detailed description, and by referring to the accompanying drawings. It should be appreciated by those skilled in the art that the conception and the specific embodiments disclosed may be readily utilized as a basis for modifying or designing other structures for carrying out the same purposes of the invention.

It should also be realized by those skilled in the art that such equivalent constructions do not depart from the spirit and scope of the invention as set forth in the appended claims.

BRIEF DESCRIPTION OF THE DRAWINGS

[0015] For a detailed description of various exemplary embodiments, reference will now be made to the accompanying drawings in which:

[0016] Figure 1 is a schematic side view of an offshore system in accordance with the principles disclosed herein for drilling and/or producing from a subsea wellbore;

[0017] Figure 2 is an enlarged partial cross-sectional view of the offshore system and strain monitoring system of Figure 1;

[0018] Figure 3 is a cross-sectional view of the offshore system of Figure 1 taken along section III-III in Figure 2;

[0019] Figure 4 is an enlarged cross-sectional view of one of the sensor assemblies of Figure 2;

[0020] Figure 5 is an enlarged perspective view of the conductor of Figure 1 illustrating the sensor array of the monitoring system of Figure 2;

[0021] Figure 6 is a schematic, partial cross-sectional view of the outer coating of the sensor assemblies of Figure 2 being applied to the conductor;

[0022] Figure 7 is a schematic cross-sectional view of the conductor of Figure 1 illustrating an external gauge ring mounted thereto;

[0023] Figures 8 and 9 are sequential schematic side views illustrating the installation of the conductor of Figure 1;

[0024] Figure 10 is a schematic side cross-sectional view of an offshore system in accordance with the principles disclosed herein for drilling and/or producing from a subsea wellbore;

[0025] Figure 11 is a top cross-sectional view taken along section XI-XI of Figure 10; and

[0026] Figure 12 is an enlarged cross-sectional view of section XII-XII of Figure 10.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0027] The following discussion is directed to various exemplary embodiments. However, one skilled in the art will understand that the examples disclosed herein have broad application, and that the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to suggest that the scope of the disclosure, including the claims, is limited to that embodiment.

[0028] Certain terms are used throughout the following description and claims to refer to particular features or components. As one skilled in the art will appreciate, different persons may refer to the same feature or component by different names. This document does not intend to distinguish between components or features that differ in name but not function. The drawing figures are not necessarily to scale. Certain features and components herein may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in interest of clarity and conciseness.

[0029] In the following discussion and in the claims, the terms "including" and "comprising" are used in an open-ended fashion, and thus should be interpreted to mean "including, but not limited to… ." Also, the term "couple" or "couples" is intended to mean either an indirect or direct connection. Thus, if a first device couples to a second device, that connection may be through a direct connection, or through an indirect connection via other devices, components, and connections. In addition, as used herein, the terms "axial" and "axially" generally mean along or parallel to a central axis (e.g., central axis of a body or a port), while the terms "radial" and "radially" generally mean perpendicular to the central axis. For instance, an axial distance refers to a distance measured along or parallel to the central axis, and a radial distance means a distance measured perpendicular to the central axis. As used herein, the term “well site personnel” is used broadly to include any individual or group of individuals who may be disposed or stationed on a rig or worksite or offsite at a remote monitoring location (such as a remote office location). The term also would include any personnel involved in the drilling and/or production operations at or for an oil and gas well such as, for example, technicians, operators, engineers, analysts, etc.

[0030] Referring now to Figure 1, an embodiment of an offshore system 10 for drilling and/or producing a subsea wellbore 11 is shown. In this embodiment, system 10 includes an offshore platform 20 at the sea surface 12, a subsea blowout preventer (BOP) 30 mounted to a wellhead 40 at the sea floor 13, and a lower marine riser package (LMRP) 50 mounted to BOP 30. Platform 20 is equipped with a derrick 21 that supports a hoist (not shown). A drilling riser 25 extends from platform 20 to LMRP 50. In general, riser 25 is a large-diameter pipe that connects LMRP 50 to the floating platform 20. During drilling operations, riser 25 takes mud returns to the platform 20.

[0031] A primary conductor 60, also referred to as conductor 60, is coupled to and extends from wellhead 40 into subterranean wellbore 11. Conductor 60 is a tubular member including a central or longitudinal axis 65, a first or upper end 60a coupled to wellhead 40, a second or lower end (not shown) disposed within the wellbore 11, a radially outer surface 60c extending axially between from end 60a, and a radially inner surface 60d also extending axially from end 60a. Inner surface 60d defines a throughbore 62 for receiving other components extending into and/or routed within wellbore (e.g., tubing, drill pipe, casing pipe, drill bits, downhole tools, etc.). During drilling and/or production operations, the primary function of conductor 60 is to resist axial and lateral loads applied to wellhead 40 by various sources (e.g., ocean currents, waves, platform 20, LMRP 50, BOP 30, etc.). As a result, it is desirable to determine and monitor the strain on conductor 60 through its term of service to avoid potential failures and losses.

[0032] Conventional systems for monitoring the strain on a conductor (e.g., conductor 60) typically involve the installation of accelerometers along the wellhead 40, BOP 30, LMRP 50, or elsewhere to measure the movement of these corresponding components. The measured movements are then used to calculate the amount of strain experienced by conductor 60. To perform this calculation, it is necessary to define a point or depth 5 below the mud line where the sediment is sufficiently consolidated to fully support conductor 60 and prevent all bending or other movement thereof. Such a point (i.e., point 5) is sometimes referred to as the "point of fixity." In the embodiment of system 10 shown of Figure 1, the vertical distance measured from the mud line to the point of fixity 5 along conductor 60 is schematically shown as depth D_5. However, determining depth D_5 is difficult, especially in subsea applications, where the sea floor 13 and conductor 60 can be located over a mile below the sea surface 12. Consequently, indirectly determining the strain experienced by a conductor via calculations relying on accelerometer measurements and estimations of depth D_5 is often imprecise, and can lead to erroneous conclusions by well site personnel (e.g., the calculated strain on conductor 60 is higher or lower than what is actually being experienced). As a result, embodiments disclosed herein include systems and methods for directly measuring the strain on a conductor (e.g., conductor 60), which offers the potential for more informed decisions by well site personnel regarding the remaining life or failure potential for the conductor 60 and related equipment.

[0033] Referring now to Figures 1 and 2, system 10 includes a strain monitoring system 100 for directly measuring and monitoring the strain experienced by conductor 60 during drilling and/or production operations. As best shown in Figure 2, in this embodiment, strain monitoring system 100 includes a sensor array 120 coupled to conductor 60 and a communication unit 150 coupled to wellhead 40. Sensor array 120 and communication unit 150 are electrically coupled such that data and information can be communicated therebetween.

[0034] Referring now to Figures 2 and 3, sensor array 120 includes a plurality of sensor assemblies 128 mounted to radially outer surface 60c of conductor 60. In this embodiment, sensor assemblies 128 are arranged into a plurality of axially stacked rows 122a, 122b, 122c, 122d. More specifically, in this embodiment, four (4) axially stacked rows 122a, 122b, 122c, 122d are provided within array 120 with row 122a being the axially uppermost row, row 122d being the axially lowermost row, row 122b being disposed immediately axially below row 122a, and row 122c being disposed axially between rows 122b and 122d. As shown in Figure 2, rows 122a, 122b, 122c are all disposed above the sea floor 13 whereas row 122d is disposed below the sea floor 13. However, in general, any desired number of rows of sensor assemblies 128 can be provided above and below the sea floor 13. For example, in some embodiments, the three axially lowermost rows 122b, 122c, 122d are disposed below the sea floor 13, and in other embodiments, all of the rows 122a, 122b, 122c, 122d are disposed below the sea floor 13.

[0035] As best shown in Figure 3, each row 122a, 122b, 122c, 122d includes four (4) uniformly circumferentially-spaced sensor assemblies 128 disposed about outer surface 60c of conductor 60. As a result, the sensor assemblies 128 in each row 122a, 122b, 122c, 122d are angularly spaced 90° apart about axis 65. Although this embodiment of system 10 includes four rows 122a, 122b, 122c, 122d of four uniformly circumferentially-spaced sensor assemblies 128, in general, other specific numbers, arrangements, and spacing for the sensor assemblies (e.g., sensor assemblies 128) can be employed while still complying with the principles disclosed herein. For example, in other embodiments, more or less than four (4) sensor assemblies 128 may be disposed within each row 122a, 122b, 122c, 122d, and sensor assemblies 128 may or may not be uniformly-circumferentially spaced about outer surface 60d. Although only one row 122b is depicted in Figure 3, it should be appreciated that each row 122a, 122c, 122d is arranged in the same manner.

[0036] Referring now to Figure 4, one sensor assembly 128 is shown, it being understood that each sensor assembly 128 is the same. Each sensor assembly 128 is secured to the radially outer surface 60c of conductor 60 and includes a plurality of protective coatings or layers disposed thereon. As will be described in more detail below, these protective coatings protect the relatively fragile strain sensing elements within assembly 128 during transport and installation of conductor 60, as well as during drilling and production operations.

[0037] In this embodiment, sensor assembly 128 includes a strain sensor 130 directly secured to radially outer surface 60c with an adhesive 132, a first or inner coating 134 disposed over and encasing sensor 130, and a second or outer coating 136 disposed over and encasing inner coating 134 and sensor 130. In general, sensor 130 can be any suitable sensor for measuring or detecting the strain on a surface including, without limitation, a resistive strain gauge, a capacitive strain gauge, a fiber strain gauge, a semiconductor strain gauge, or the like. In this embodiment, sensor 130 is a resistive based strain gauge that includes a metallic foil pattern having a total of three (3) terminals for connection to an electrical power source (however, it should be appreciated that such sensors may have more or less than three terminals, such as, for example, two or four terminals while still complying with the principles disclosed herein). When the foil pattern is deformed (e.g., as a result of strain experienced by the support surface that the sensor is mounted to), the electrical resistance across the foil pattern between two of the terminals changes, and this change in electrical resistance can be directly correlated to an amount of strain on the support surface (e.g., in some embodiments the electrical resistance can be related to the strain by a gauge factor which is known and based on the particular type, size, etc. of strain sensor used). In some embodiments, sensor 130 may comprise a load cell such has those manufactured and sold by Interface of Scottsdale, AZ (specific examples including the model 1010) and Tovey Engineering of Phoenix, AZ (specific examples including the model SW10). In other embodiments, sensor 130 may comprise a strain gauge used within a pressure transducer such as those manufactured and sold by Omega Engineering, Inc. of Stamford, CT (specific examples including the PX409 pressure transducer) and Honeywell International Inc. of Morris Township, New Jersey (specific examples including the SPT series pressure transducers). In still other embodiments, sensor 130 may comprise a wireless surface acoustic wave (“SAW”) sensor such as those manufactured by Syntonics L.L.C. of Columbia, MD or by Applied Sensor Research & Development Corp. of Arnold, MD. Also, in some embodiments, sensor 130 may be similar to one or more of those described in U.S. Pat. Nos. 7,268,662, 7,434,989, 7,500,379, 7,791,249, 8,094,008, 8,441,168 and U.S. Pat. App. Pub. Nos. 2013/0130362 and 2014/0007692, wherein the contents of each of the above references are incorporated by reference in their entirety for all purposes.

[0038] In addition, sensor 130 may comprise a strain gauge configured to measure or detect the strain on outer surface 60c along either a single axis (e.g., an axis oriented parallel with axis 65, an axis disposed within a plane that is perpendicular to axis 65, or an axis that is disposed somewhere between parallel and perpendicular to axis 65) or along multiple axes all while still complying with the principles disclosed herein. In this embodiment, sensor 130 is configured to measure the strain on surface 60c of conductor 60 along an axis oriented parallel to axis 65.

[0039] In this embodiment, sensor assembly 128 also includes a temperature sensor 131 adjacent to strain sensor 130. In general, temperature sensor 131 can be any suitable temperature sensing device or apparatus known in the art, such as, for example, a thermocouple, a thermistor, a thermometer (e.g., a resistive thermometer), etc. In this embodiment, temperature sensor 131 is positioned circumferentially adjacent to strain sensor 130 as shown, however, in other embodiments, the temperature sensor (e.g., temperature sensor 131) may be axially or radially adjacent to strain sensor 130. In addition, in this embodiment, each of the sensor assemblies 128 include both strain sensor 130 and temperature sensor 131. However, in other embodiments, sensor assemblies 128 may only include one of the strain sensor 130 and temperature sensor 131, and in still other embodiments, some of the sensor assemblies 128 may include both sensors 130, 131, and others of the sensor assemblies 128 may include only one of the sensors 130, 131.

[0040] Adhesive 132 secures sensors 130, 131 to conductor 60. In general, adhesive 132 can comprise any adhesive suitable for use in subsea and/or downhole environments (i.e., adhesives capable of withstanding the anticipated temperatures, pressures, etc.in the subsea and/or downhole environment). In this embodiment, adhesive 132 comprises an epoxy resin. An example of a suitable epoxy resin is a two-part epoxy available from Vishay Precision Group, Inc. of Raleigh, North Carolina (specific examples including, but not limited to M-Bond 610 adhesive and M-Bond AE-15 adhesive), and HBM, Inc. of Marlborough, Massachusetts (specific examples including, but not limited to EP-310S adhesive and X280 adhesive). In addition, in at least some embodiments, radially outer surface 60c (or simply the portion of outer surface 60c that sensors 130, 131 will be mounted to) is subjected to a surface treatment prior to applying adhesive 132. Specifically, in some embodiments, outer surface 60c is shot blasted (e.g., with shot peen) to result in a white metal surface finish. The purpose of these surface treatments is to promote adhesion between adhesive 132 and surface 60c, thereby promoting a secure mounting for sensor 130, 131. Further, in embodiments where sensors 130, 131 are arranged radially adjacent one another, additional adhesive 132 may be disposed radially between sensors 130, 131 to secure sensors 130, 131 to one another.

[0041] Referring still to Figure 4, as previously described, sensors 130, 131 are encased and protected by a plurality of protective coatings 134, 136. Such coatings 134, 136 are designed to protect sensors 130, 131 from damage caused both by mechanical impact as well as contact with potentially corrosive or damaging fluids (e.g., chemicals, saltwater, hydrocarbon fluids, etc.). Inner coating 134 is disposed immediately around and over sensors 130, 131 such that it contacts both of the sensors 130, 131 as well as a region or portion 64 of outer surface 60c immediately surrounding sensor 130. In general, coating 134 can comprise any suitable coating material(s) configured to restrict the ingress of water, formation fluids, or other fluids from the area immediately surrounding conductor 60 toward sensors 130, 131. In addition, coating 134 should also maintain a certain level of elasticity and deformability so that it does not interfere with the ability of sensor 130 (and potentially also sensor 131) to deform under the influence of strain experienced by conductor 60. For example, in this embodiment, coating 134 has a tensile strength TS_{134} that is equal to approximately 530 psi [or 3654 kPa], an elongation e_{134} of 350%, and a Durometer A hardness of 55. In addition, coating 134 exhibits minimal corrosion, adhesion loss, or softening when exposed to salt water and jet fuel. Further, in this embodiment, inner coating 134 is an electrical insulator, and thus, is configured to shield sensors 130, 131 from outside electrical influences during operations. In some embodiments, coating 134 comprises multiple layers of bonding material, TEFLON® sheet(s), metallic foil, carbon fiber, other coating agents, or combinations thereof. In this embodiment, coating 134 comprises a resin material such as, for example a two-part polysulfide Permapol® P-5 liquid polymer like PR-1770 available from PPG Industries, Inc. of Sylmar, CA.

[0042] In general, inner coating 134 can be applied to sensors 130, 131 in any suitable manner, such as, for example, extrusion, smearing, rolling, spraying, etc. In addition, once inner coating 134 is applied to sensors 130, 131 it can be cured in any suitable manner such as, for example, by radiative heat, ultraviolet (UV) light, etc. In some embodiments, coating 134 is cured involuntarily or naturally through an exothermic reaction; however, without being limited to this or any other theory, increasing the temperature by using heat lamps or applying the coating in a warm environment may accelerate the curing process. It should be appreciated that the curing method and parameters may affect the resulting properties of coating 134, such as for, example, the hardness, flexibility, etc. One of ordinary skill would appreciate the proper curing methods and parameters which would result in the desired properties discussed above.

[0043] Referring still to Figure 4, outer coating 136 is disposed immediately around and over inner coating 134 such that it contacts both inner coating 134 and at least a region or potion 68 of outer surface 60c immediately surrounding inner coating 134. In general, coating 136 can comprise any suitable coating material(s) configured to protect sensors 130, 131 from damage caused by mechanical impacts. Such impacts may occur during transportation, handling, installation, and use of conductor 60, and can include, impacting conductor 60 (particular the region of outer surface 60c proximate sensors 130, 131) with another object. In some embodiments, outer coating 136 comprises one or more layers of urethane, carbon fiber, fiberglass, metallic wiring, rubber, and/or other resins. In this embodiment, coating 136 comprises a resin material such as, for example polyurethane compound like PR-1535 available from PPG Industries, Inc. of Sylmar, CA. In addition, because coating 136 is utilized to guard against physical impacts and other direct trauma to sensor assembly 128, it should also maintain a certain level of toughness – which is a measure of a material's ability to absorb energy and plastically deform without fracturing or failing. Toughness can also be thought of as a combination of tensile strength and elongation. For example, in this embodiment, coating 136 has a tensile strength TS_{134} that is equal to approximately 4500 psi [or 31,030 kPa], an elongation e_{136} of 500%, and a Durometer A hardness of 90.

[0044] Therefore, in this embodiment, the tensile strength TS_{136} and elongation e_{136} of outer coating 136 is greater than the tensile strength TS_{134} and elongation e_{134} of inner coating 134, and the hardness of outer coating 136 is greater than the hardness of the inner coating 134. Accordingly, outer coating 136 has a greater toughness than inner coating 134. As a result, inner coating 134 is able to accommodate deformation of sensor 130 (and potentially also sensor 131) and resist fluid ingress toward sensors 130, 131, while outer coating 136 is able to protect sensors 130, 131 from mechanical impacts. Also, as can be determined from the specific materials properties given above, the tensile strength TS_{136} of outer coating 136 is approximately 8.5 times greater than the tensile strength TS_{134} of inner coating 134, and the elongation e_{136} of outer coating 136 is approximately 1.4 times the elongation e_{134} of inner coating 134.

[0045] Referring still to Figure 4, it is generally desirable to limit the radial distance to which sensor assemblies 128 extend from conductor 60 to reduce the potential for sensor assemblies 128 to physically interfere with other equipment during operations (e.g., transportation, handling, installation, etc.). As a result, in this embodiment, outer coating 136 has an outer surface 136a disposed at a maximum distance R_{128} measured from radially outer surface 60c of conductor 60. In this embodiment, radial distance R_{128} preferably ranges from 0 to 0.5 inches; however, other values are possible (e.g., values above 0.5 inches). Typically, the upper limit of radial distance R_{128} is determined by the maximum radial distance to which other components of conductor 60, such as couplers, extend. Therefore, limiting radial distance R_{128} such that it is equal to or preferably less than the radial distance of these other components of conductor 60 prevents at least some engagement with sensor assemblies 128 during operations.

[0046] In general, coatings 134 and 136 can be applied in any suitable manner in order to fully and sufficiently cover and encase sensors 130, 131 and inner coatings 134, respectively. Referring now to Figure 5, in this embodiment, inner coating 134 and outer coating 136 are applied in a plurality of strips 139, 140, respectively, that extend axially along radially outer surface 60c of conductor 60. As shown in Figure 5, each strip 139 includes a first or upper end 139a, a second or lower end 139b opposite upper end 139a, and an axial length L_{139} extending between ends 139a, 139b. Axial length L_{139} is sized such that each strip 139 covers one of the sensors 130, 131 of each row 122a, 122b, 122c, 122d. Specifically, one sensor 130 in each row 122a, 122b, 122c, 122d is axially aligned with a corresponding sensor 130 in each of the other rows 122a, 122b, 122c, 122d. Similarly, one sensor 131 in each row 122a, 122b, 122c, 122d is axially aligned with a corresponding sensor 131 in each of the other rows 122a, 122b, 122c, 122d. Each strip 139 extends axially over each of the axially aligned sensors 130, 131. In addition, each strip 140 includes a first or upper end 140a, a second or lower end 140b opposite upper end 140a, and an axial length L_{140} extending between ends 140a, 140b. Axial length L_{140} is sized such that each strip 140 covers one of the strips 139 (and the corresponding sensors 130 covered thereby). Therefore, in this embodiment, axial length L_{140} is preferably equal to or greater than axial length L_{139}. Without being limited to this or any other theory, this arrangement of coatings 134, 136 has the added benefit of preventing free rolling of conductor 60 about axis 65 when it is resting on radially outer surface 60c, such as might be the case during storage and transportation of conductor 60.

[0047] Referring now to Figures 2 and 5, each sensor 130 and each sensor 131 is coupled to an electrical connector 126 mounted to outer surface 60c. In particular, a plurality of electrical conductors 129 electrically couple sensors 130, 131 to connector 126. Preferably, each conductor 129 extends between one of the sensors 130, 131 and connector 126 (note: only a single conductor 129 is shown extending across sensors 130 in rows 122a, 122b, 122c, 122d in Figure 5 for simplicity). In this embodiment, conductors 129 comprise TEFLON® insulated wires (i.e., conductors 129 include wires insulated with polytetrafluoroethylene, perfluoroalkoxy, fluorinated ethylene propylene, or combinations thereof); however, other coatings and insulation are possible. Also, in this embodiment (where conductors 129 are coated in TEFLON®) it is preferable to etch the insulation with a Fluorocarbon Etchant to promote a strong bond between the insulation and one or more of the coatings (e.g., coatings 134, 136, 137, etc.). For example, in some embodiments, conductor 129 insulation is etched with Tetra-Etch® available from Polytetra of Mönchengladbach, Germany. In addition, in at least some embodiments, the insulation of conductors 129 is prepped to promote waterproofing thereof in a manner suitable for such purposes as would be known and appreciated by one of ordinary skill in the art. As is best shown in Figure 5, at least a part of each conductor 129 is encased by one of the strips 139, 140 of coatings 134, 136, respectively. In addition, in this embodiment, additional coating material(s) 137 encases portions of conductors 129 that are not proximate sensor assemblies 128. Without being limited to this or any other theory, coating 137 provides strain relief for conductors 129 as well as protection from egress of conductors 129 and connector 126. Coating 137 may be the same or different as coating 136 or coating 134 while still complying with the principles disclosed herein. In some embodiments, at least a portion of conductors 129 that extend above the sea floor 13 are not encased by coatings 134, 136, or 137 while still complying with the principles disclosed herein. In general, electrical connector 126 can be any suitable electrical connector for coupling and transferring power, data, communication signals, or combinations thereof between sensors assemblies 128 and other components (e.g., communication unit 150 described in more detail below). In this embodiment, connector 126 comprises a dry mateable electrical connector 126 mounted to radially outer surface 60c.

[0048] In general, strips 139, 140 of coatings 134, 136 can be disposed on outer surface 60c of conductor 60 by any suitable method while still complying with the principles disclosed herein. However, as best shown Figure 6, in this embodiment each strip 140 of outer coating 136 is formed by constructing or forming a mold 145 around one sensor 130 of each row 122a, 122b, 122c, 122d after inner coating 134 is applied and cured. Mold 145 includes an inner cavity 146 sized and shaped to correspond with the desired size and shape of each strip 140. Therefore, cavity 146 has a total axial length (with respect to axis 65) that is equal to length L_{140}, previously described. In addition, mold 145 includes an upper end 145a, a lower end 145b, an outlet 149 at upper end 145a, and an inlet 147 at a lower end 145b. Both inlet 147 and outlet 149 provide access to cavity 146. To fill mold cavity 146, an injector 143 is connected to inlet 147 and injects the material(s) making up outer coating 136 from a supply 141 into cavity 146 in at least a semi-liquid state. Simultaneously with the injection of outer coating 136 into cavity 146 at inlet 147, a vacuum or negative pressure is created at outlet 149 with a vacuum pump 148, thereby creating a pressure differential across cavity 146 between inlet 147 and outlet 149. As a result, injected coating 136 is drawn up (via the differential pressure) within cavity 146 from inlet 147 toward outlet 149. After cavity 146 has been completely filled, mold 145 is removed and outer coating 136 is cured in any suitable manner such as, for example, by radiative heat, ultraviolet (UV) light, or placing coating 136 in a warm environment of approximately 80-130°F. As is similarly explained for inner coating 134, it should be appreciated that the curing method and parameters may affect the resulting properties of coating 136, such as for, example, the hardness, flexibility, etc. One of ordinary skill would appreciate the proper curing methods and parameters which would result in the desired properties discussed above. In addition, it should be appreciated that strips 139 of inner coating 134 may be formed through a similar process to that described above for strips 140 while still complying with the principles disclosed herein.

[0049] Referring now to Figure 7, an external gauge ring 180 is disposed about conductor 60 axially below sensor array 120 to clear sediment in advance of array 120 during insertion of conductor 60 into the sea floor. In particular, in this embodiment, ring 180 includes a first or upper end 180a, a second or lower end 180b opposite upper end 180a, a radially outer surface 180d extending between ends 180a, 180b, and a radially inner surface 180c extending between ends 180a, 180b. In this embodiment, inner surface 180c is cylindrical and engages radially outer surface 60c of conductor 60. Outer surface 180d includes a downward facing frustoconical surface 184 at lower end 180b and an outer cylindrical surface 182 extending axially between frustoconical surface 184 and upper end 180a. Outer cylindrical surface 182 extends to a maximum radius R_{180} measured radially from outer surface 60c that is preferably equal to or greater than the radius R_{128} of sensor assemblies 128. In at least some embodiments, radius R_{180} is preferably less than the maximum radial distance to which other components of conductor 60, such as couplers, extend to avoid interference by ring 180 during installation and handling of conductor 60 as previously described above. In this embodiment, radius R_{180} is preferably less than 0.5 inches. In general, gauge ring 180 may be installed on radially outer surface 60c in any suitable manner while still complying with the principles disclosed herein. For example, ring 180 may be secured to outer surface 60c through welding, adhesive, securing members (e.g., bolts, rivets, etc.), interference fit, or combinations thereof.

[0050] Referring now to Figures 8 and 9, during insertion of conductor 60 into the sea floor 13, frustoconical surface 184 of gauge ring 180 engages with sediment and directs it radially away from radially outer surface 60c of conductor 60 and thus also away from the trailing sensor array 120. Because radius R_{180} is preferably equal to or larger than radius R_{128} of sensor assemblies 128 within array 120 (Figure 7), ring 180 pushes sediment is radially beyond the reach of sensor assemblies 128 by as conductor 60 is advanced into sea floor. Therefore, the installation of gauge ring 180 offers the potential to reduce excessive engagement between the sediment below the sea floor 13 and sensor array 120, which can prevent damage to array 120 during conductor 60 installation operations.

[0051] Referring again to Figure 2, communication unit 150 is received within a receptacle 46 mounted to a radially extending mounting bracket 44 extending from wellhead 40. Communication unit 150 is configured to receive data from each of the sensors 130, 131 within sensor array 120 (e.g., strain measurements, temperature measurements, etc.) during drilling and/or production operations, and transmit that received data to a remote surface location. The remote surface location may be any location that is removed from wellhead 40 and system 100, and may include any suitable location for receiving data such as, for example, a control room. In this embodiment, the remote surface location is disposed on platform 20. In this embodiment, communication unit 150 includes a wet mateable electrical connector 154 coupled to connector 126 with a cable 127. As previously described above, connector 126 is electrically coupled to sensors 130 in array 120 via conductors 129. The connection between cable 127 and connector 154 may be made up by a remote operated vehicle (ROV) subsea or may be made up by well site personnel at platform 20.

[0052] Communication unit 150 also includes a wireless transmitter 152 configured to communicate, via wireless signals 160, with the remote surface location (e.g., platform 20). In general, wireless signals 160 can comprise any suitable wireless communication signal for communication across atmospheric or oceanic space. For example, signals 160 may comprise acoustic waves, radio waves, light waves, etc. In this embodiment, signals 160 comprise acoustic signals. Transmitter 152 is configured to both transmit and receive wireless signals (e.g., signals 160) during operation, and thus, communication unit 150 is configured to send and receive signals to and from both sensor array 120 and the remote surface location (e.g., platform 20).

[0053] In this embodiment, communication unit 150 is configured to receive raw data from sensors 130, 131 (e.g., electrical resistance, voltage, impedance, etc. readings from sensors 130, 131), calculate the resulting strain, temperature measurements, respectively, from the raw data, and then communicate the strain, temperature measurements to the remote location.

Accordingly, communication unit 150 includes a processor configured to execute software stored on a memory.

[0054] Referring again to Figures 1-4, during drilling and/or production operations (i.e., following installation of systems 10, 100), any strain experienced by conductor 60 (particularly on outer surface 60c) causes deformation of sensors 130 within array 120. The sensors 130 then output signals that include changes in at least one parameter as a result of the deformation (e.g., resistivity). This raw data signal is then routed to communication unit 150 via electrical conductors 129, connector 126, and cable 127, where it is then translated into a measurement of strain on conductor 60. The strain measurements communicated to communication unit 150 are then communicated wirelessly to platform 20 via communication signals 160. In at least some embodiments, strain measurements are taken at a sufficient sampling frequency in order for well site personnel to characterize cyclic loading conditions on conductor 60. In addition, in some embodiments, the data output from sensors 130 and/or stored and communicated by communication unit 150 may be sufficiently compressed through known methods to allow for more efficient transmission and analysis thereof.

[0055] While embodiments disclosed herein have focused on the measurement of strain on the outermost conductor tubular (e.g., conductor 60), it should be appreciated that other embodiments can also be utilized to measure and monitor the strain on other tubulars, such as, for example, other casing or conductor tubulars disposed within the outermost conductor of an oil and gas well. For example, referring now to Figure 10, another offshore system 200 for drilling and/or producing subsea wellbore 11 is shown. System 200 is substantially the same as system 10, previously described, and thus, corresponding components are given the same reference numerals and the following description will focus on the differences between systems 10, 200. Specifically, in addition to the components of system 10, system 200 includes a second or inner conductor 210 extending concentrically within conductor 60 along axis 65. Inner conductor 210 includes a first or upper end 210a coupled to wellhead 40, a second or lower end (not shown) disposed within wellbore 11, a radially outer surface 210c extending axially from end 210a, and a radially inner surface 210d also extending axially from end 210a. As shown in Figure 10, when inner conductor 210 is concentrically disposed within conductor 60, an annulus 205 is formed between radially inner surface 60d of conductor 60 and radially outer surface 210c of inner conductor 210.

[0056] Referring now to Figures 10 and 11, system 200 also includes a strain monitoring system 220 for directly measuring and monitoring the strain experienced by conductor 210 during drilling and/or production operations. System 200 may include strain monitoring system 220 either in addition to or in lieu of strain monitoring system 100 previously described above. Strain monitoring system 220 includes a communication assembly 230 mounted to radially outer surface 60c of conductor 60 and a strain measurement assembly 260 mounted to radially outer surface 210c of inner conductor 210.

[0057] As is best shown in Figure 11, communication assembly 230 is a ring-shaped member that extends circumferentially about the radially outer surface 60c of conductor 60. Assembly 230 includes and houses a plurality of acoustic transducers 232 that are circumferentially spaced about axis 65 along surface 60c. Communication assembly 230 can be secured to outer surface 60c of conductor 60 through any suitable method while still complying with the principles disclosed herein. For example, in some embodiments, communication assembly 230 is a clam shell style member that includes two circumferential halves that are joined by a hinge (not shown) thereby allowing assembly 230 to be closed about radially outer surface 60. In other embodiments, assembly 230 is welded or bolted to radially outer surface 60c. In still other embodiments, assembly 230 is secured to radially outer surface 60c with an interference fit or an adhesive.

[0058] Each transducer 232 includes one or more piezoelectric elements that allow each transducer 232 to generate acoustic signals (e.g., acoustic waves) in response to the receipt of input electrical signals (i.e., electric current), and further, to output electrical signals (i.e., electric current) in response to the receipt of input acoustic signals. Accordingly, each transducer 232 can be referred to as being a "piezoelectric" transducer. In this embodiment, each transducer 232 is configured to generate and receive acoustic signals having frequencies between 100 MHz and 2000 MHz; however, other frequency ranges are possible. In general, each piezoelectric transducer 232 can be any suitable piezoelectric transducer known in the art while still complying with the principles disclosed herein, and in some embodiments may include transducers that are configured to communicate with other non-acoustic wireless signals, such as, for example, optical signals, radio frequency (RF) signals, WiFi, BLUETOOTH®, etc.

[0059] Power and/or communication signals (e.g., electromagnetic signals, light signals, etc.) routed to and from transducers 232 in communication assembly 230 may be carried by a conductor 236, shown in Figure 10. Conductor 236 is routed from communication assembly 230 along outer surface 60c either to another communication device (e.g., communication unit 150, previously described) or to some other remote location (e.g., platform 20). In this embodiment, conductor 236 is routed to platform 20. Conductor 236 is configured substantially the same as conductors 129, previously described, and may include any suitable conductor, such as, for example, wires or fiber optic cabling. In addition, conductor 236 may include a plurality of individual conductive elements (not shown) that are each coupled to one of the transducers 232 at one end and a separate component (e.g., communication unit 150, device or component disposed on platform 20, etc.) at an opposite end.

[0060] Referring still to Figures 10 and 11, strain measurement assembly 260 is circumferentially disposed about the radially outer surface 210c of inner conductor 210. As a result, assembly 260 is disposed within annulus 205. Strain measurement assembly 260 generally includes a protective outer ring member 262, and a plurality of strain sensor assemblies 128 (which may potentially include temperature sensor 131 as described above), each being the same as previously described above. Sensor assemblies 128 are mounted to and are circumferentially spaced about radially outer surface 210c. As a result, assemblies 128 are configured to measure the strain (and potentially temperature) on inner conductor 210 during operations. In addition, in this embodiment, assembly 260 includes a power storage and delivery unit 264 (referred to more simply herein as "power unit 264") and a communication transducer 266. Each of the sensor assemblies 128, power unit 264, and transducer 266 are coupled (e.g., electrically or otherwise) to one another with one or more conductors 268 extending along or proximate to radially outer surface 210c.

[0061] Referring now to Figures 11 and 12, ring member 262 provides a protective outer shell to the other components of strain measurement assembly 260 during manufacturing, transportation, installation, and production operations for conductor 210. As best shown in Figure 12, member 262 includes a first or upper end 262a, a second or lower end 262b, a radially outer surface 262c, and a radially inner surface 262d. An annular recess 263 extends radially inward from radially inner surface 262d. Recess 263 contains and houses each of the sensor assemblies 128, power unit 264, transducer 266, and conductor(s) 268 during operations. As with communication assembly 230, ring member 262 may be secured to radially outer surface 210c of inner conductor 210 through any suitable method, such as, for example, welding, bolting, interference fit, adhesive, clamping, etc. In this embodiment, member 262 is a clam-shell type member that includes two circumferential halves joined by a hinge (not shown). In at least some embodiments, recess 263 is sealed from the environment in annulus 205. Such a seal may be achieved and maintained in any suitable manner while still complying with the principles disclosed herein. For example, in at least some embodiments, a pair of annular seal assemblies (not shown) are disposed on radially inner surface 262d, with one above recess 263 and the other below recess 263. Each seal assembly may include an annular seal gland extending radially inward from radially inner surface 262d and a sealing member (metallic, non-metallic, compliant, etc.) disposed therein that engages radially outer surface 210c when member 262 is installed on conductor 210.

[0062] Referring still to Figures 11 and 12, as previously described, each sensor assembly 128 disposed within recess 263 is configured substantially the same as described above for strain monitoring system 100. Specifically, as best shown in Figure 12, each sensor assembly 128 includes a strain sensor 130 (and possibly a temperature sensor 131) that is encased by an inner coating 134, which is further encased by an outer coating 136. Sensor 130 (and sensor 131 if applicable) and coatings 134, 136 are the same as previously described above, and thus, a detailed description is omitted for conciseness. Each of the sensors 130 (and sensors 131 if applicable) of assemblies 128 is coupled to power unit 264 and transducer 266 through conductor(s) 268 as previously described. As shown in Figure 11, in this embodiment, a total of four (4) sensor assemblies 128 are disposed about radially outer surface 210c, and each sensor assembly 128 is uniformly-circumferentially spaced such that each assembly 128 is circumferentially spaced approximately 90° from each immediately adjacent sensor assembly 128. However, as previously described above, sensor assemblies 128 need not be uniformly-circumferentially spaced about radially outer surface 210c, and more or less than four (4) sensor assemblies 128 may be included while still complying with the principles disclosed herein.

[0063] Communication transducer 266 is configured substantially the same as transducers 232 of communication assembly 230. Therefore, transducer 266 is configured to generate acoustic signals (e.g., acoustic waves) in response to the receipt of input electrical signals (i.e., electric current), and further, to output electrical signals (i.e., electric current) in response to the receipt of input acoustic signals. In this embodiment, transducer 266 is configured to communicate wirelessly with any one or more (or all) of the transducers 232 through annulus 205 and conductor 60 (i.e., across surfaces 60d, 60c). In general, one or more (or all) transducers 232 receive electric signals (i.e., an electric current) from conductor 236, converts the electric signals into acoustic signals 238 (i.e., acoustic waves 238), and outputs the acoustic signals 238 to transducer 266. In addition, transducer 266 receives acoustic signals (i.e., acoustic signals 238 output from transducer(s) 232), converts the acoustic signals into electric signals (i.e., an electric current), and outputs the electric signals to power unit 264 and/or sensors 130 (e.g., through conductors 268). Further, transducers 266 receives electric signals from one or more of the sensors 130, converts the electric signals into acoustic signals 239 (i.e., acoustic waves 239), and outputs the acoustic signals 239 to one or more of the transducers 232. In addition, one of more of the transducers 232 receive acoustic signal 239 (i.e., acoustic waves 239 output from transducer 266), converts the acoustic signals 239 into electric signals, and outputs the electric signals to conductor 236. In some embodiments, an additional conversion unit (or multiple conversion units) is disposed within recess 263 and is configured to convert electrical signals received from transducer 266 into a different signal format for submission to sensors 130 and/or power unit 264 as well as to convert signals received from sensors 130 and/or power unit 264 into electrical signals (e.g., when the signals received from sensors 130 and/or power unit 264 are other than electromagnetic signals) for submission to transducer 264. Such a conversion unit would be particularly useful for embodiments where sensors 130 are coupled to transducer 266 through a wireless connection (e.g., RF, acoustic, WiFi, etc.). In addition, it should be appreciated that communication transducers 266, 232 may operate in substantially the same manner to communicate signals from the temperature sensors 131 if such sensors are included in one or more of the sensor assemblies 128 as described above.

[0064] Further, during communication operations between transducer(s) 232 and transducer 266, in at least some embodiments the signal(s) from platform 20 and output from transducer(s) 232 are of a sufficient strength (i.e., the signals are strong enough account for expected attenuation due to environmental conditions) such that they provide the electrical power necessary to run various components of system 100 (e.g., transducer 266, sensors 130, etc.). For example, in some embodiments transducer 266 may be configured to receive some amount of electric energy that is taken from signals emitted from transducer(s) 232 which may then be stored in power unit 264 and utilized to power transducer 266, and sensors 130 for all operations described herein. Alternatively, for some embodiments transducer 266 may continuously receive power from transducer(s) 232 through acoustic signals throughout operations which again may then be utilized to power transducer 266 and sensors 130, 131 for all operations described herein. In at least some of these embodiments, the acoustic signals for transferring power from transducer(s) 232 to transducer 266 may be at a different frequencies or on different channels than other communication signals (e.g., through frequency-division multiplexing). In addition, in some embodiments acoustic communication between transducers 232, 266 may only occur in one direction at any given time (e.g., either from transducer(s) 232 to transducer 266 or from transducer 266 to transducer(s) 232) such as, for example, through time-division multiplexing. Alternatively, in other embodiments acoustic communication between transducers 232, 266 may occur in both directions simultaneously (e.g., simultaneously from transducer(s) 232 to transducer 266 and from transducer 266 to transducer(s) 232.)

[0065] Power unit 264 is configured to store and deliver electrical power to each of the sensors 130, 131 within assemblies 128 as well as transducer 266 during operations. Power unit 264 may comprise any suitable element or device for storing and delivering electrical power, while still complying with the principles disclosed herein, such as, for example, a battery, capacitor, a wireless power receiver, or combinations thereof. During operations, electrical power is delivered to and stored in power unit 264 via the acoustic communication between transducer 266 and one or more of the transducers 232 in the manner previously described above.

[0066] During strain measurement operations, sensors 130 measure the strain on inner conductor 210 in the same manner as described above and output signals (that include either strain measurement values or some other measured value indicative of the strain such as a change in electric resistivity) to communication transducer 266 through conductors 268. Transducer 266 then converts the received signals from sensors 130 into an acoustic signal 239 and routes signal 239 through annulus 205 and conductor 60 where it is received by one or more of the transducers 232 within communication assembly 230. The received acoustic signal 239 is then converted back to an electromagnetic signal and routed to platform 20 (or some other remote location or device as described above) through conductor 236. During these operations, measurements or data may be generated by sensors 130 either automatically based on a set and predetermined time period (e.g., every minute, hour, day, week, etc.) or upon receipt of an interrogation signal originating from platform 20 or some other remote location. Specifically, in some embodiments, an interrogation signal is routed via conductor 236 from some other remote location (e.g., platform 20) to transducers 232 in assembly 230. Upon receipt of the interrogation signal, one or more (or all) of the transducers 232 convert the electromagnetic signal into an acoustic interrogation signal 238 which is then routed across conductor 60 and annulus 205 to transducer 266, which receives and converts signal 238 back to an electromagnetic interrogation signal in the manner previously described above. Thereafter, the newly converted interrogation signal is routed through conductors 268 to one or more (or all) of the sensors 130 which then take a reading of the strain on inner conductor 210 and output a measurement signal as described above. It should be appreciated that the communication operations with temperature sensors 131 is substantially the same as discussed above for strain sensors 130.

[0067] During these communication operations, at least partially circumferential and axial alignment between transducer 266 and at least one of the transducers 232 is preferred to allow for effective communications therebetween. In this embodiment, circumferential alignment is ensured since a plurality of transducers 232 are provided circumferentially about radially outer surface 60c. Thus, no matter where transducers 266 is located circumferentially along radially outer surface 210c of inner conductor 210, it will be at least partially circumferentially aligned with one of the transducers 232. Axial alignment of assemblies 230, 260 is ensured by careful placement thereof along conductors 60, 210, respectively, and is facilitated by the fact that both conductors 60, 210 are coupled to wellhead 40 at known (or determinable) axial positions.

[0068] In the manner described, through use of a strain monitoring system in accordance with the principles disclosed herein (e.g., system 100), direct measurement and monitoring of the strain experienced by a wellhead conductor (e.g., conductor 60) is possible. As a result, well site personnel are able to determine whether the conductor is nearing a failure event due to excess strain, and can therefore take appropriate action to avoid the ultimate failure and mitigate any damage potentially caused thereby.

[0069] While preferred embodiments have been shown and described, modifications thereof can be made by one skilled in the art without departing from the scope or teachings herein. The embodiments described herein are exemplary only and are not limiting. Many variations and modifications of the systems, apparatus, and processes described herein are possible and are within the scope of the disclosure.

[0070] For example, while embodiments of the strain monitoring system 100 have been described for use in an offshore drilling and/or production system 10, it should be appreciated that embodiments of the strain monitoring system 100 disclosed herein may be utilized on a land based drilling and/or production system while still complying with the principles disclosed herein. In addition, while embodiments of the communication unit 150 disclosed herein have been described as receiving raw data output from sensors 130 and then converting that raw data into strain measurements for communication to the remote surface location (e.g., on platform 20), it should be appreciated that in other embodiments, sensors 130 determine the strain on conductor 60 from the measured parameter(s) and then route these determined strain measurements to communication unit 150 via conductors 129, connector 126, and cable 127 as previously described. Also, in still other embodiments, the raw data out put from the sensors 130 is converted into a measurement of strain on conductor 60 at the remote surface location (e.g., at platform 20). Further, although communication unit 150 as described here in wirelessly communicates strain measurements to the remote location in real time or near real time, in other embodiments, the communication unit (e.g., communication unit 150) simply stores all received data for later retrieval to the remote surface location (e.g., platform). For example, in some embodiments, communication unit 105 stores data and is retrieved to the sea surface 12 by an ROV. Still further, while embodiments of strain measurement assembly 260 have included a transducer 266 for communication with one or more transducers 232 in communication assembly 230, it should be appreciated that in other embodiments, sensors 130 themselves may directly communicate with transducers 232 without the aid of a transducers 266. For example, in some embodiment, each sensor 130 may include a wireless transceiver which is configured to produce an acoustic signal for transmission across annulus 205 and conductor 60 for receipt by one or more of the transducers 232. Also, it should be appreciated that embodiments for measuring and monitoring the strain on an inner conductor (e.g., such as conductor 210 and the embodiment shown in Figures 10-12) may be utilized along with an embodiment of a strain monitoring system for measuring and monitoring the strain on an outer conductor (e.g., such as conductor 60, and the embodiment of Figures 1-5). When such assemblies and systems are utilized together, communication assembly 230 may additionally function as a collection point for measurement signals not only from sensors 130 disposed on radially outer surface 210c of inner conductor 210, but may also collect signals from sensors 130 disposed on radially outer surface 60c of outer conductor 60. It should further be appreciated that communication unit 150 can be mounted anywhere proximal to wellhead 40 or other similarly situated components (e.g., production tree) and need not be directly mounted to wellhead 40 as previously described above. While embodiments disclosed herein include sensor assemblies 128 that are all configured the same, it should be appreciated that other embodiments include sensors assemblies 128 that are configured differently (e.g., different sensor types, different coating arrangements, thicknesses, types, etc.) while still complying with the principles disclosed herein.

[0071] Accordingly, the scope of protection is not limited to the embodiments described herein, but is only limited by the claims that follow, the scope of which shall include all equivalents of the subject matter of the claims. Unless expressly stated otherwise, the steps in a method claim may be performed in any order. The recitation of identifiers such as (a), (b), (c) or (1), (2), (3) before steps in a method claim are not intended to and do not specify a particular order to the steps, but rather are used to simplify subsequent reference to such steps.

CLAIMS

What is claimed is:

1. A system, comprising:

a tubular member including a radially outer surface; and

a sensor assembly comprising:

a strain sensor coupled to the radially outer surface of the tubular member;

a first coating having a first hardness and a first tensile strength, wherein the first coating encases the strain sensor and at least part of the radially outer surface of the tubular member;

a second coating having a second hardness that is greater than the first hardness and a second tensile strength that is greater than the first tensile strength, wherein the second coating encases the first coating and at least another part of the radially outer surface of the tubular member.

2. The system of claim 1, wherein the strain sensor assembly extends radially outward to a distance from the radially outer surface of the tubular member that is less than about 0.5 inches.

3. The system of claim 1, further comprising:

an electrical conductor that is coupled to the strain sensor and extends along the radially outer surface of the tubular member, wherein the second coating encases at least a portion of the electrical conductor; and

an electrical connector that is coupled to the electrical conductor and disposed on the radially outer surface of the tubular member.

4. The system of claim 1, wherein the first coating is an electric insulator and is configured to restrict contact of liquid disposed around the tubular member with the strain sensor; and

wherein the second coating comprises one of at least one of resin, carbon fiber, and rubber.

5. The system of claims 1 2, 3, or 4, further comprising an external gauge ring disposed about the radially outer surface of the tubular member, axially below the sensor assembly;

wherein the external gauge ring includes a frustoconical lower surface and a radially outer surface; and

wherein the radially outer surface of the external gauge ring is radially outward from the second coating of the sensor assembly.

6. The system of claims 1, 2, 3, or 4, further comprising a communication unit in communication with the strain sensor; wherein the communication unit is configured to communicate with a remote surface location via a wireless signal.

7. The system of claim 6, further comprising:

a temperature sensor coupled to the radially outer surface of the tubular member;

wherein the communication unit is in communication with the temperature sensor.

8. The system of claims 1, 2, 3, or 4, further comprising:

an inner tubular disposed within the tubular member such that an annulus is formed between the inner tubular and the tubular member, wherein the inner tubular has a radially outer surface;

a second strain sensor coupled to the radially outer surface of the inner tubular;

a first transducer coupled to the radially outer surface of the tubular member;

a second transducer coupled to the radially outer surface of the inner tubular;

wherein the second transducer is electrically coupled to the second strain sensor; and

wherein the first transducer is configured to wirelessly communicate with the second transducer across the annulus.

9. The system of claim 8, further comprising:

a ring member disposed about the radially outer surface of the inner tubular;

wherein the ring member includes an annular recess, wherein the second strain sensor and the second transducer are disposed within the annular recess; and

a power unit disposed within the annular recess and configured to store electrical power and deliver electrical power to the second transducer and the second strain sensor.

10. A method of measuring strain on a first conductor for use in an oil and gas well, the method comprising:

(a) measuring a strain on the first conductor with a first strain sensor coupled to a radially outer surface of the first conductor;

(b) protecting the first strain sensor during (a) with an outer coating;

(c) routing data from the first strain sensor to a communication unit after (a);

(d) wirelessly communicating with a remote surface location with the communication unit after (c).

11. The method of claim 10, wherein (a) comprises deforming the first sensor with the strain on the first conductor; and wherein the method further comprises:

(e) accommodating the deformation in (a) with an inner coating disposed between the outer coating and the first strain sensor; and

(f) resisting contact between liquids disposed about the first conductor and the first strain sensor with the inner coating.

12. The method of claims 10 or 11, further comprising:

(g) forcing the first conductor into a wellbore before (a);

(h) engaging sediment in the wellbore during (g) with an external gauge ring disposed about the first conductor below the first strain sensor; and

(i) forcing the sediment radially away from the radially outer surface of the first conductor during (h).

13. The method of claim 10 or 11, further comprising:

(j) measuring strain on a second conductor disposed within the first conductor with a second strain sensor coupled to a radially outer surface of the second conductor; and

(k) routing data from the second strain sensor across an annulus formed between the first conductor and the second conductor.

14. The method of claim 13, wherein (k) comprises routing data from the second strain sensor across the annulus with a wireless signal.

15. The method of claim 14, wherein the wireless signal comprises an acoustic signal.

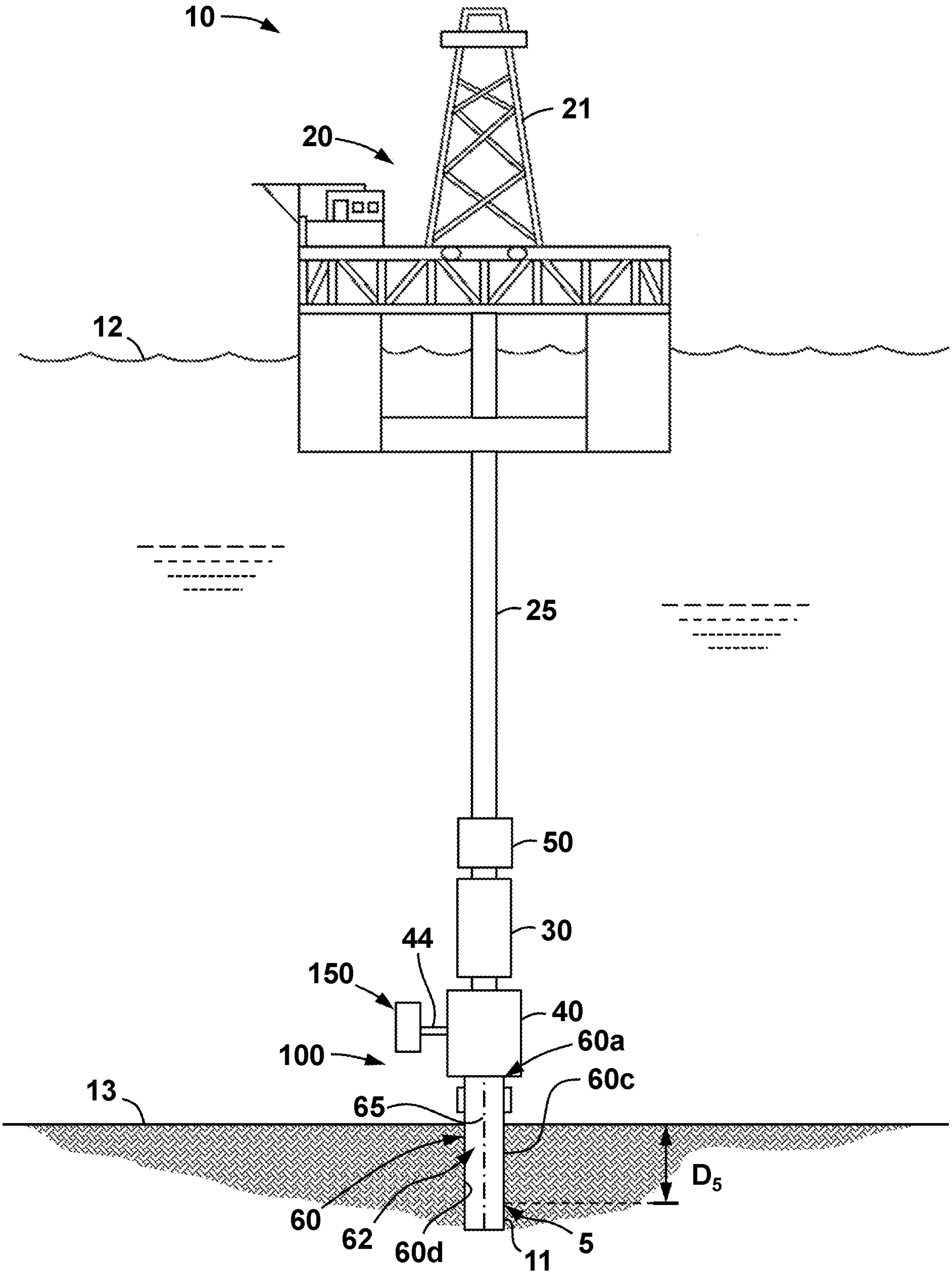
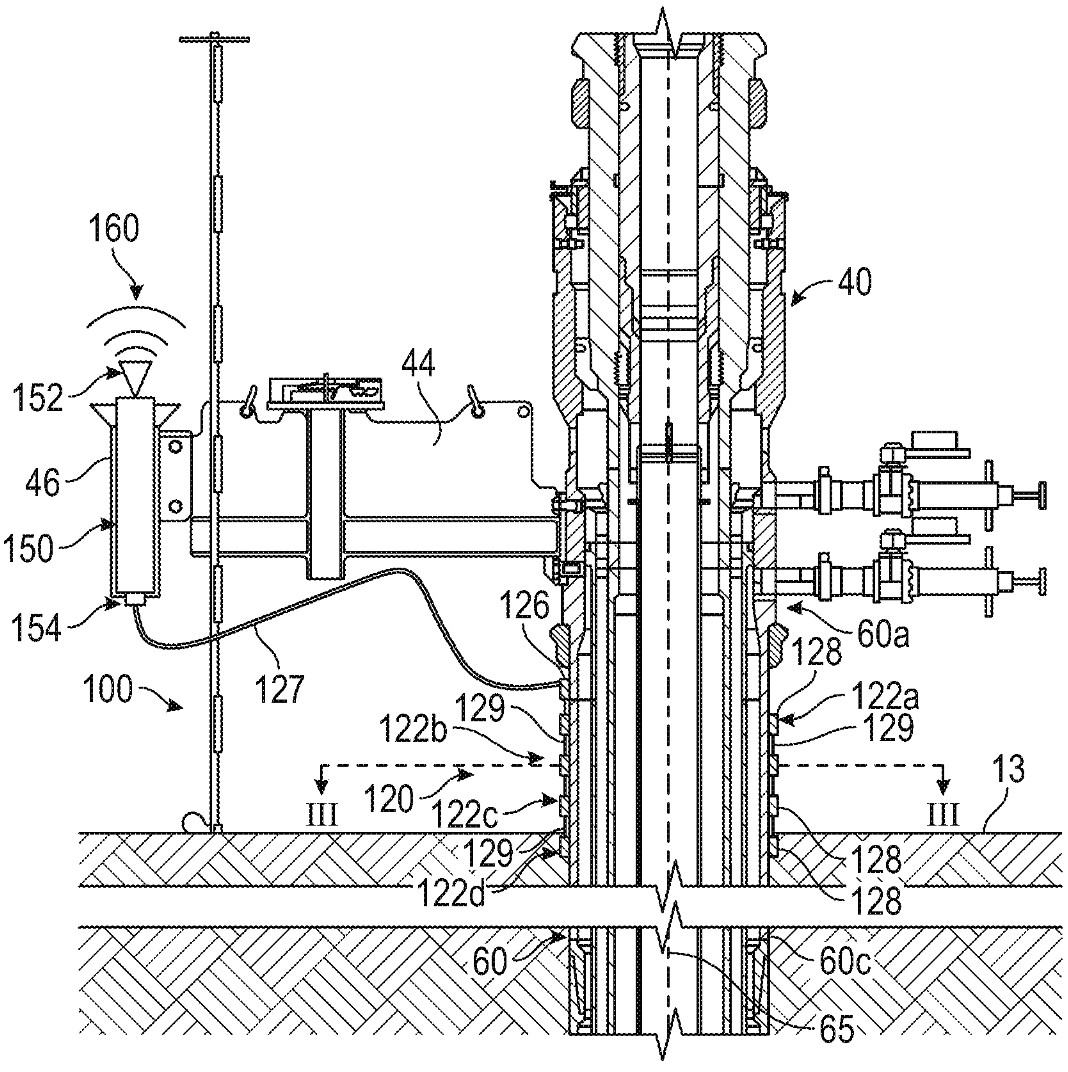


FIG. 1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154
100
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127
126
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128
122a
129
122b
120
III
122c
129
122d
60
13
128
128
60c
65

FIG. 2

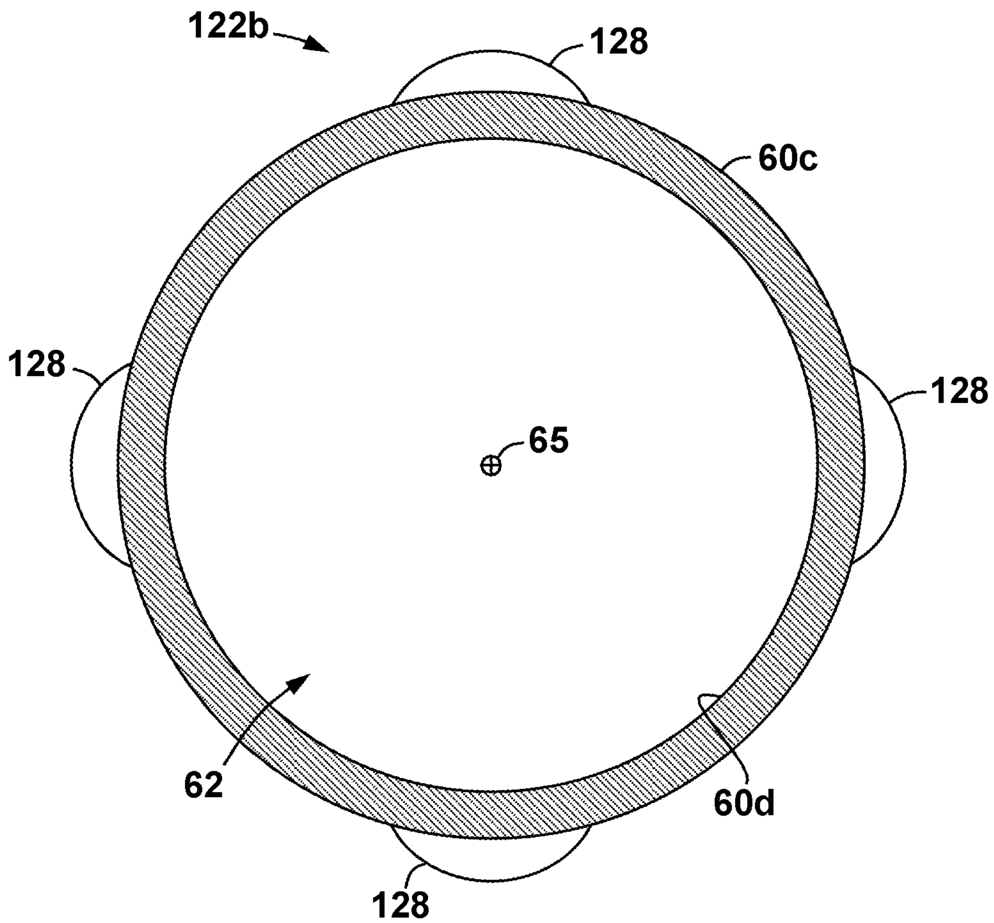


FIG. 3

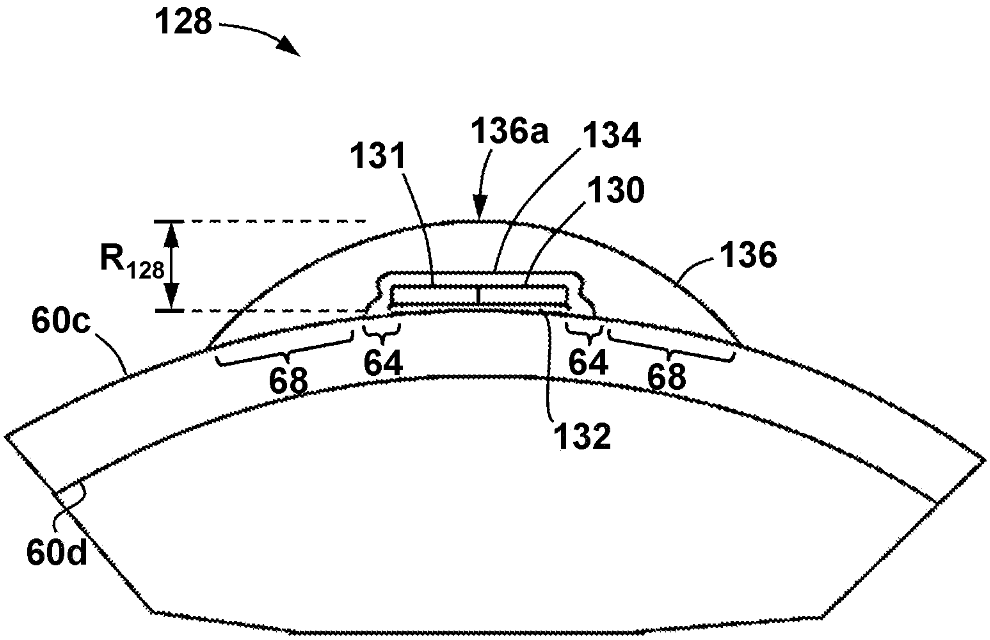
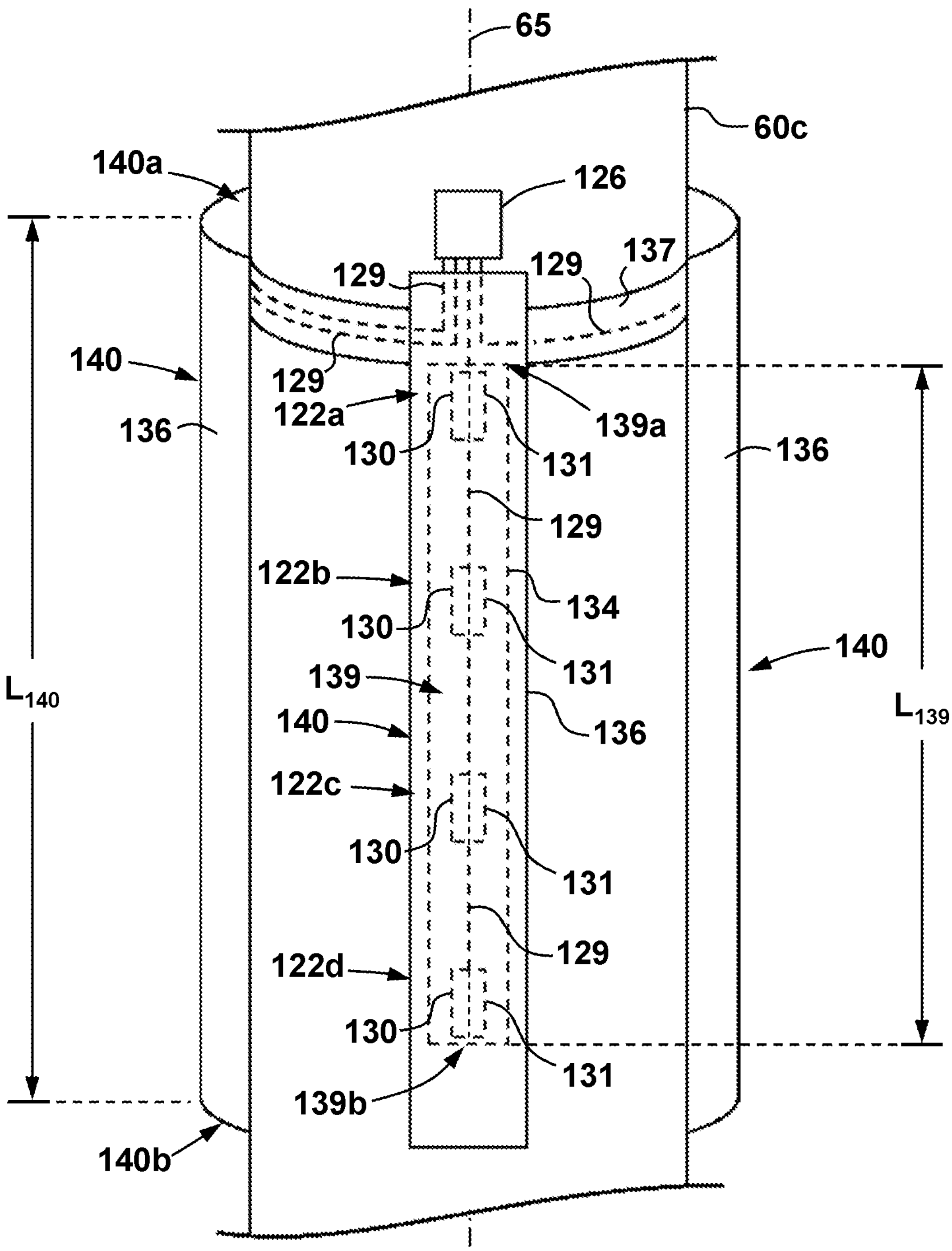


FIG. 4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126
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137
129
140
129
122a
139a
136
130
131
136
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122b
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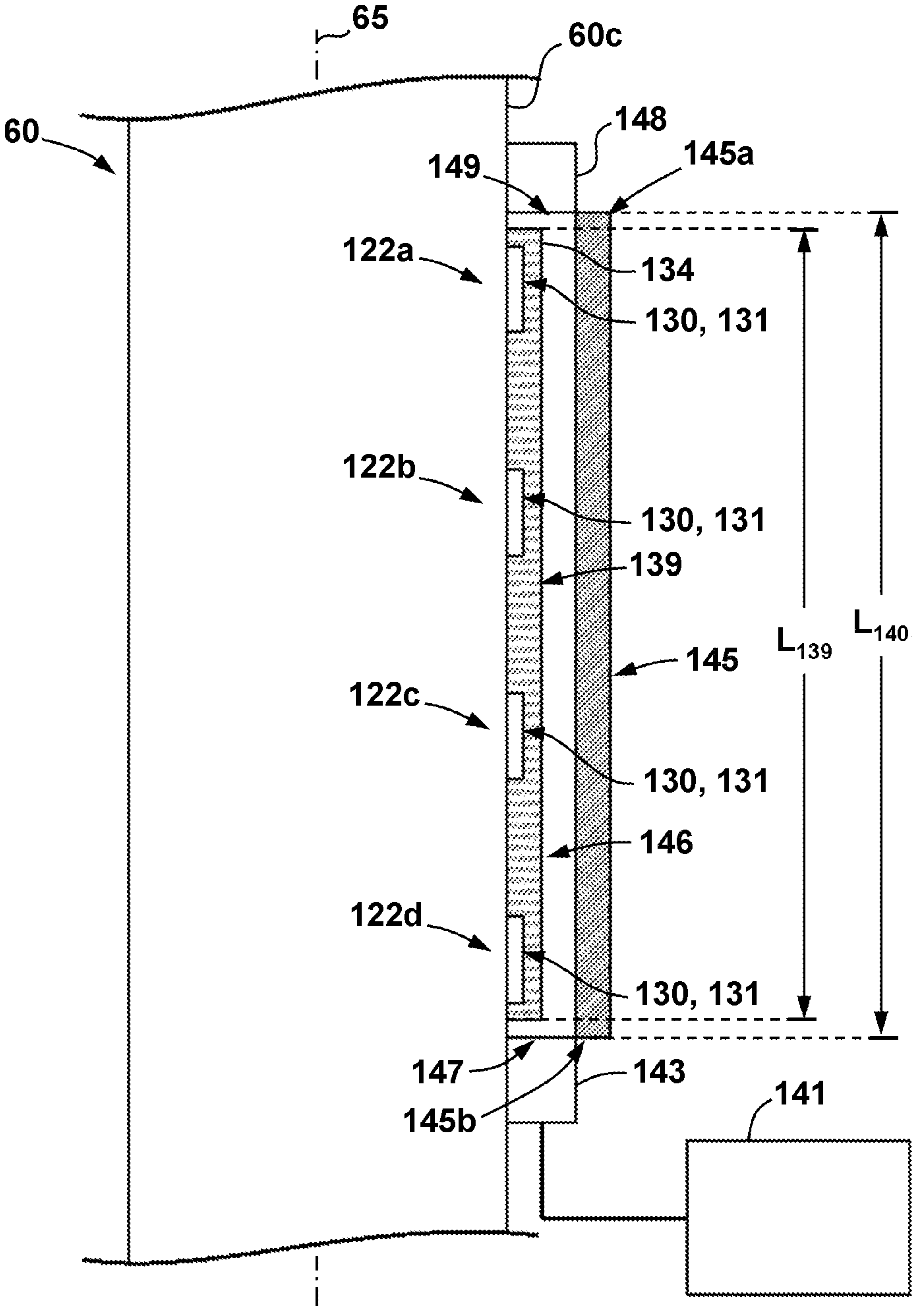
130
140
131
139
L_{140}
L_{139}
140
136
122c
130
131
129
122d
130
131
139b
140b

FIG. 5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122b
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L$_{139}$
L$_{140}$
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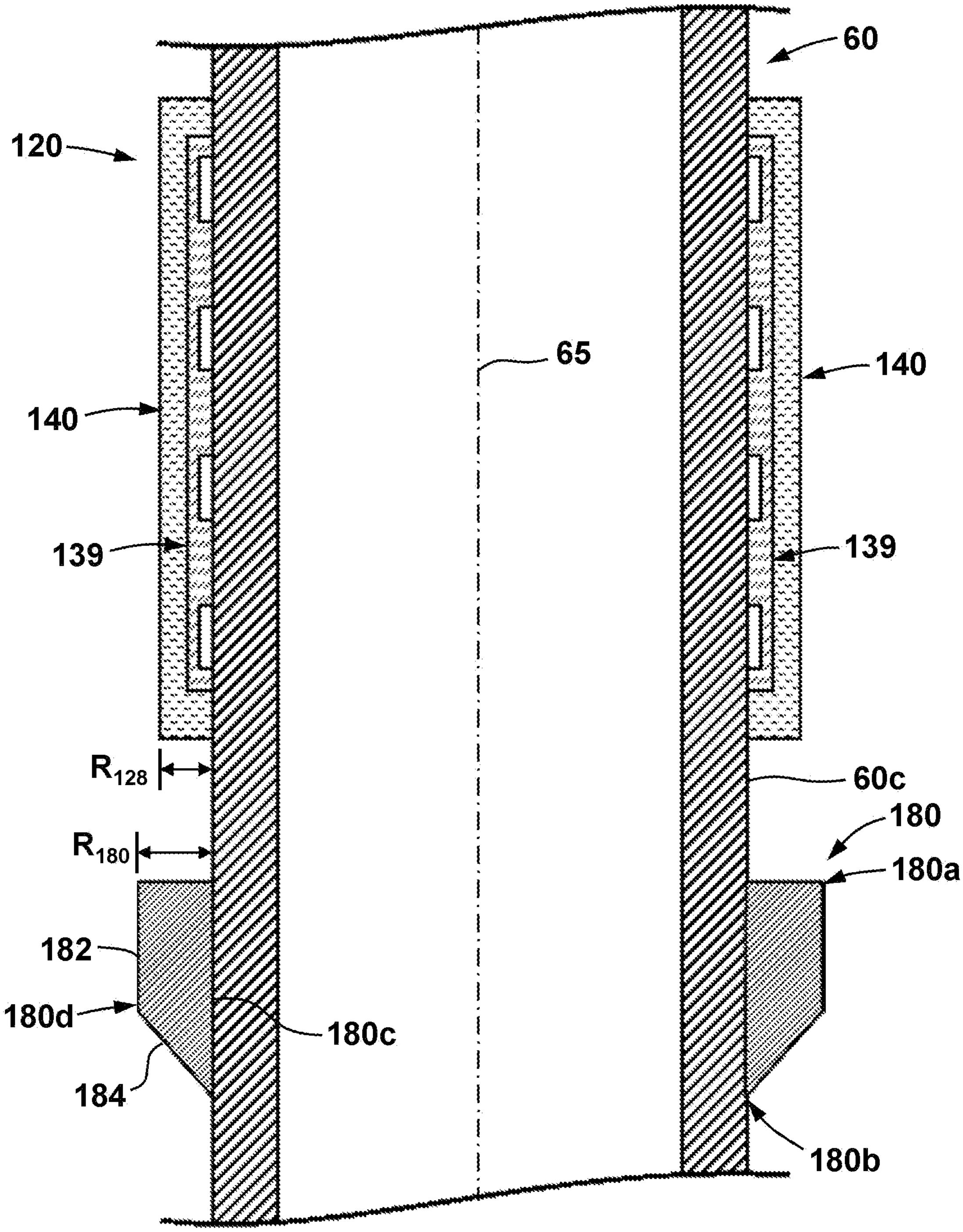
122c
130, 131
146
122d
130, 131
147
143
145b
141

FIG. 6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120
65
140
140
139
139
R_{128}
60c
R_{180}
180
180a
182
180d
180c
184
180b

FIG. 7

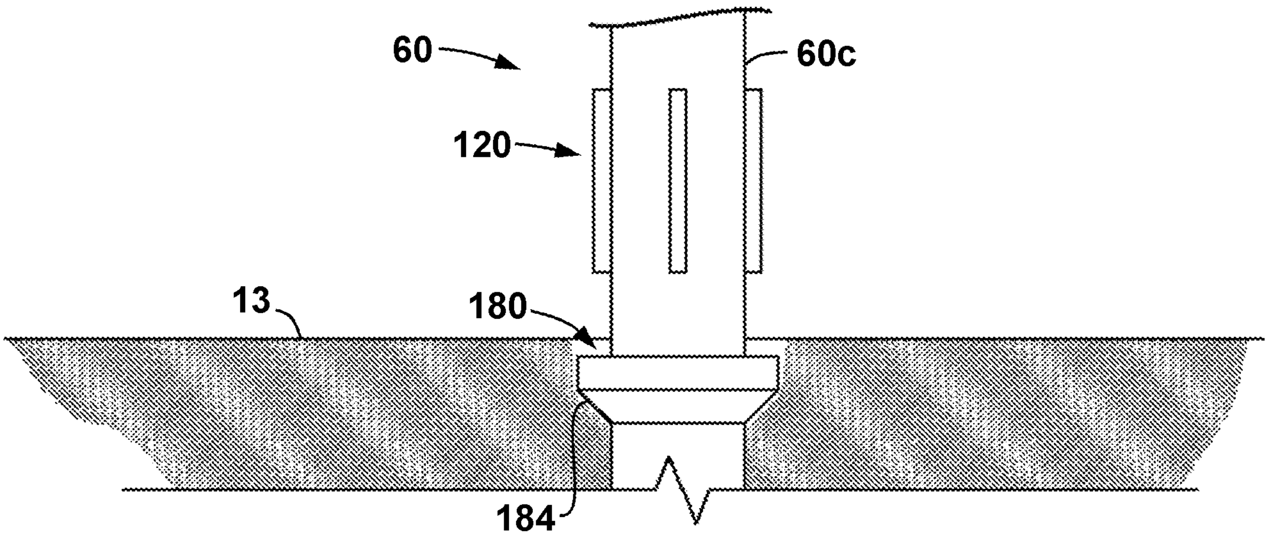


FIG. 8

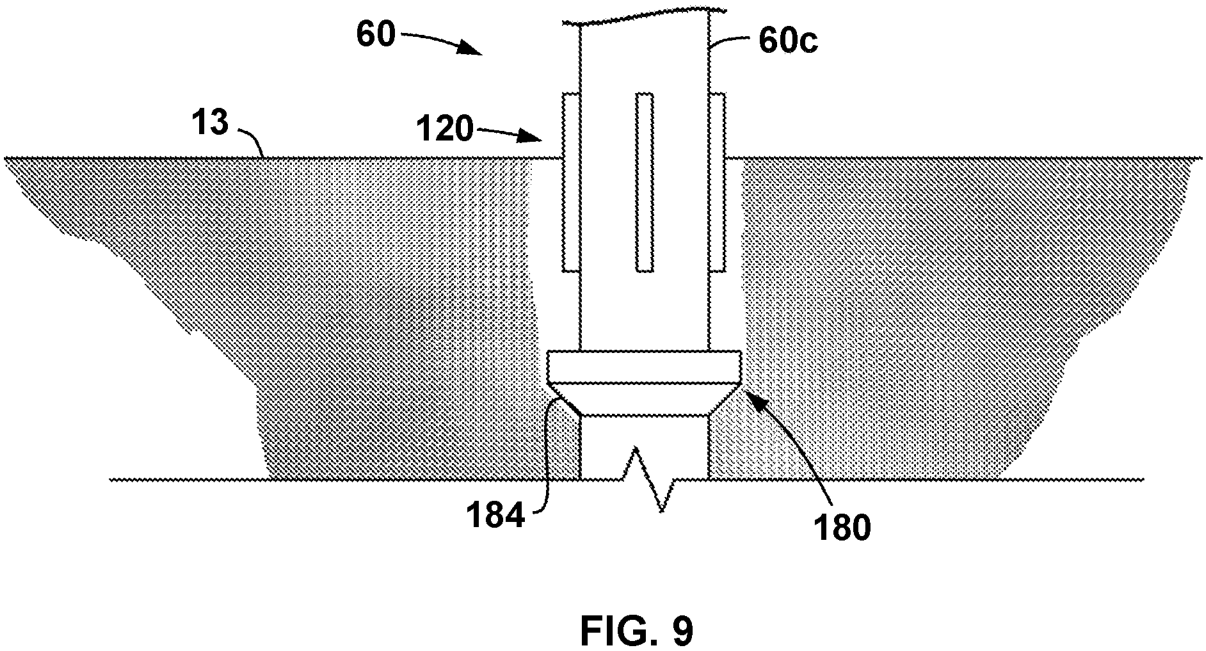
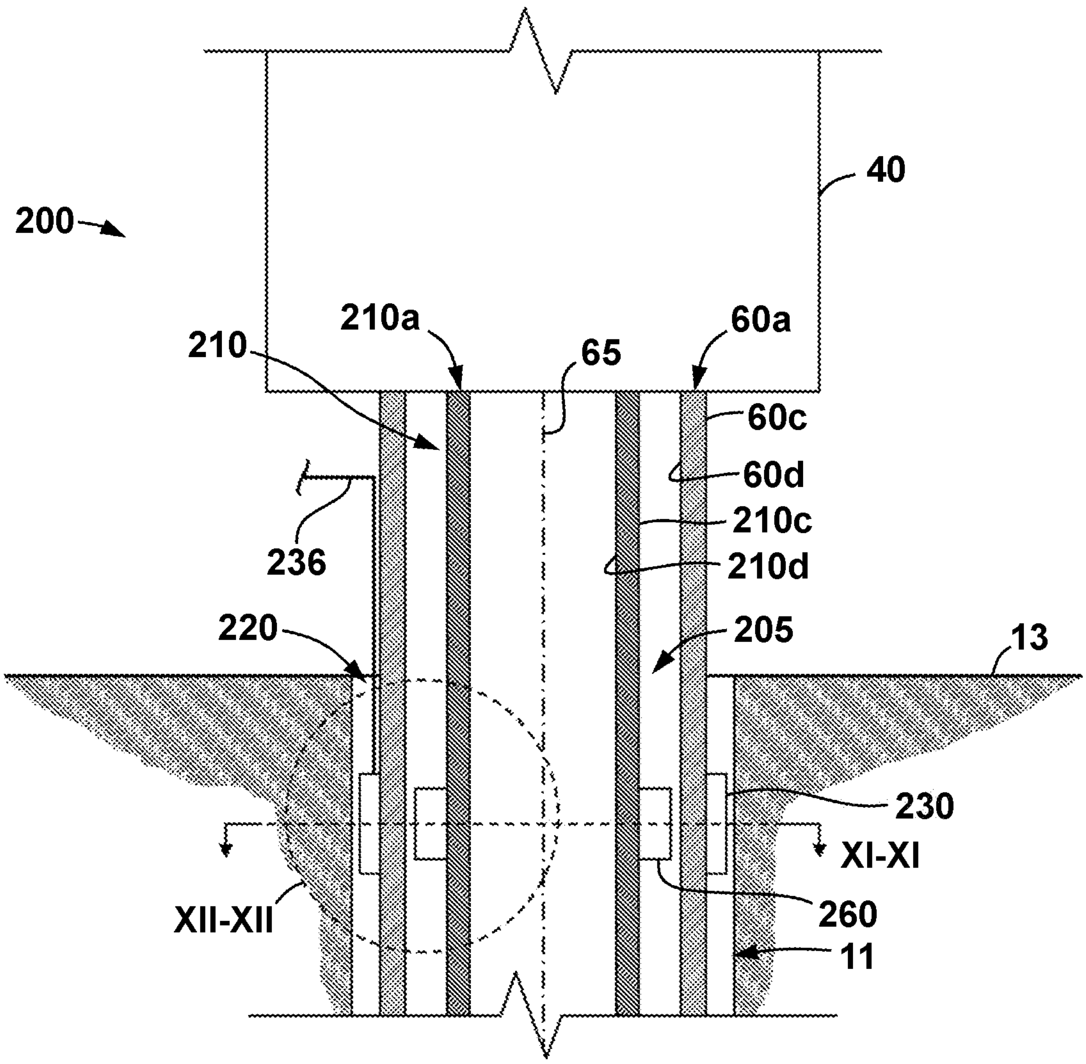


FIG. 9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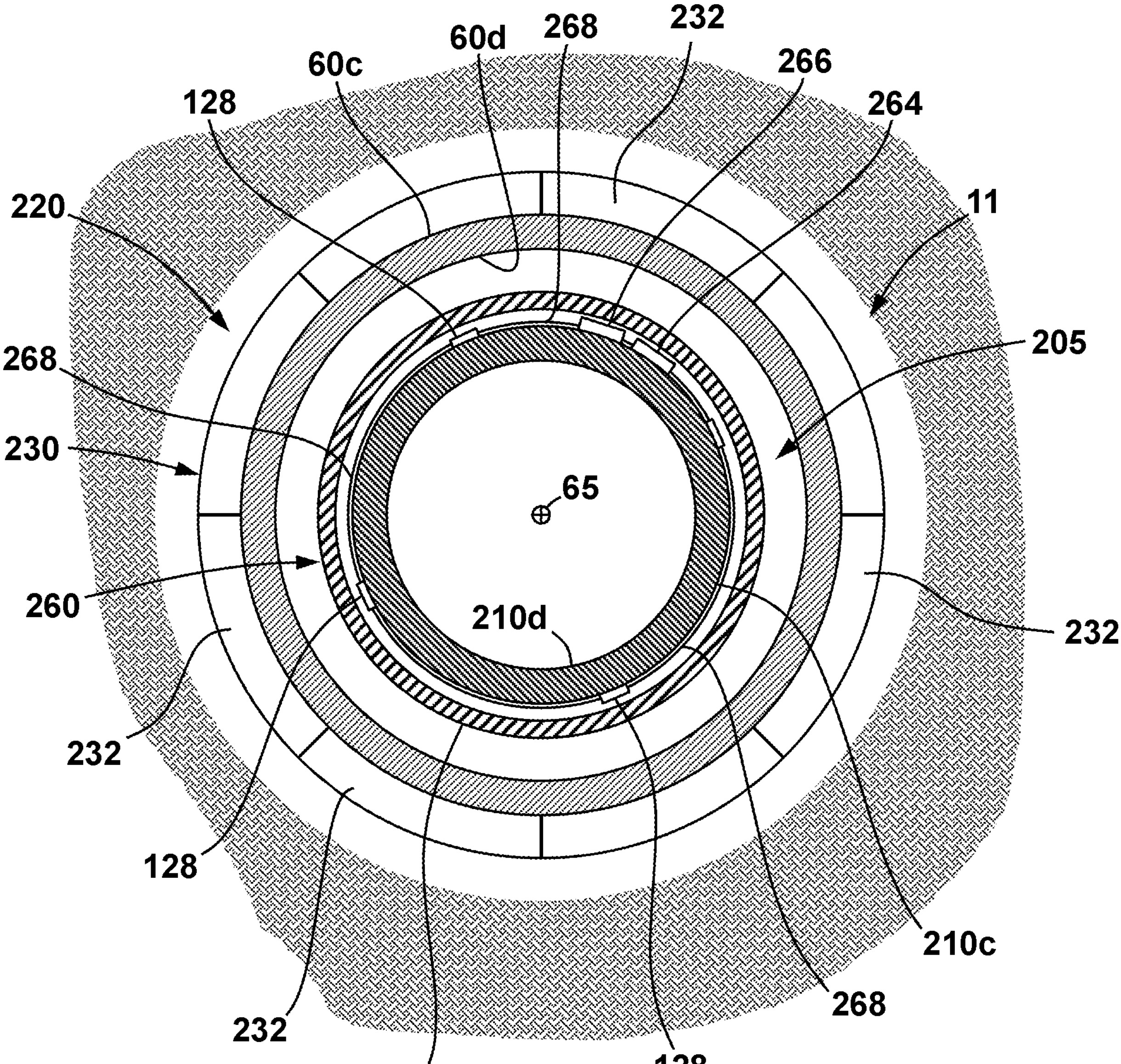
200
210a
60a
210
65
60c
60d
236
210c
210d
220
205
13
230
XI-XI
XII-XII
260
11

FIG. 10


232
268
60d
60c
266
128
264
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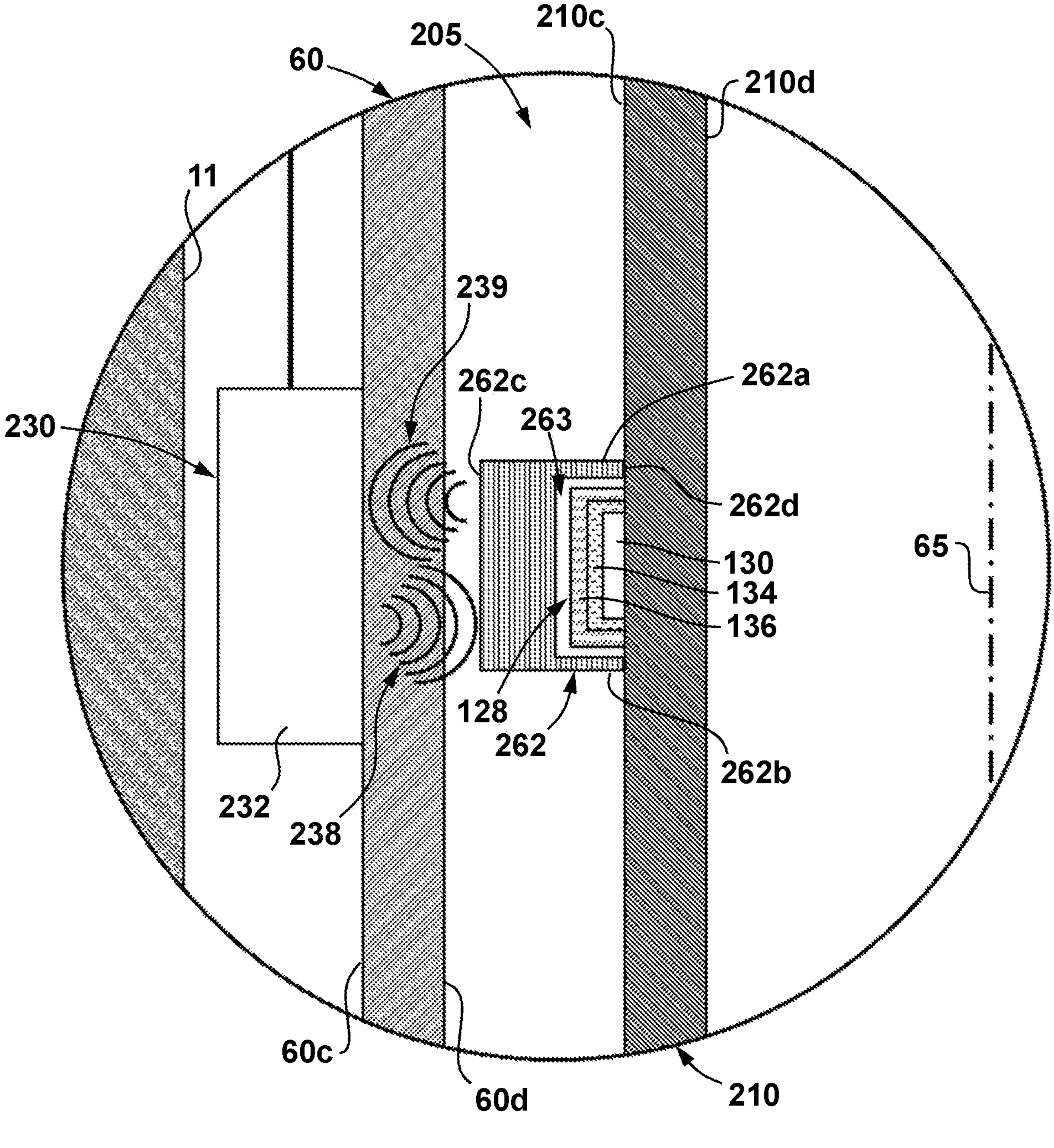
268
230
65
260
210d
232
232
232
128
128
262
268
210c

FIG. 11



210c
205
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210d
11
239
262c
262a
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263
262d
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134
136
128
262
262b
232
238
60c
60d
210

FIG. 12

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2016/027699

A. CLASSIFICATION OF SUBJECT MATTER
INV. E21B47/00 E21B47/01 E21B43/10
ADD.

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 G01B G01L

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

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

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X Y	WO 2014/096667 A1 (VALLOUREC TUBES FRANCE [FR]) 26 June 2014 (2014-06-26) page 5, line 6 - line 14; figures 1,2 page 11, line 16 - page 12, line 26 page 13, line 18 - page 14, line 31 page 33, line 10 - line 15 -----	1-4,6,7, 10,11 5,8,9, 12-15
Y	WO 2009/040510 A2 (QINETIQ LTD [GB]; BOWLES ADRIAN ROBERT [GB]; EATON STUART JOHN [GB]; H) 2 April 2009 (2009-04-02) claim 1; figure 1 -----	8,9, 13-15
X	JP 2009 128009 A (FUJIKURA LTD) 11 June 2009 (2009-06-11) abstract; figures 1,2 -----	1-4,6,7

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[X] Further documents are listed in the continuation of Box C.

[X] See patent family annex.

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"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
13 July 2016	25/07/2016

Name and mailing address of the ISA/	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Fax: (+31-70) 340-3016	Dantinne, Patrick

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INTERNATIONAL SEARCH REPORT

International application No
PCT/US2016/027699

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	WO 2008/001046 A1 (SCHLUMBERGER HOLDINGS; SCHLUMBERGER CA LTD [CA]; PRAD RES & DEV LTD; S) 3 January 2008 (2008-01-03) paragraph [0025] - paragraph [0029]; figures 3,4	5,12
X,P	US 9 279 666 B1 (BALASUBRAMANIAM MAHADEVAN [US] ET AL) 8 March 2016 (2016-03-08) column 5, line 42 - line 58; figures 1,4,5,6,10	1-4,6,7
A	G.W. KING ET AL: "The Instrumentation of the Conductor of a Subsea Well in the North Sea To Measure the Installed Conditions and Behavior Under Load", SPE DRILLING AND COMPLETION, vol. 10, no. 04, 1 December 1995 (1995-12-01), pages 265-270, XP055288032, US ISSN: 1064-6671, DOI: 10.2118/26838-PA figure 2	1-15
A	GB 2 483 675 A (TUNGET BRUCE ARNOLD [GB]) 21 March 2012 (2012-03-21) abstract; figures 15,16	5,12
A	US 3 089 107 A (DEAN III MILLS) 7 May 1963 (1963-05-07) claim 1; figures 1,2	1-15
A	US 2013/213129 A1 (KUMAR SUNIL [DE] ET AL) 22 August 2013 (2013-08-22) paragraph [0022]; figures 3-7 paragraph [0028] - paragraph [0029]	1-15

1

INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No
PCT/US2016/027699

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			WO	2013126396	A1	29-08-2013