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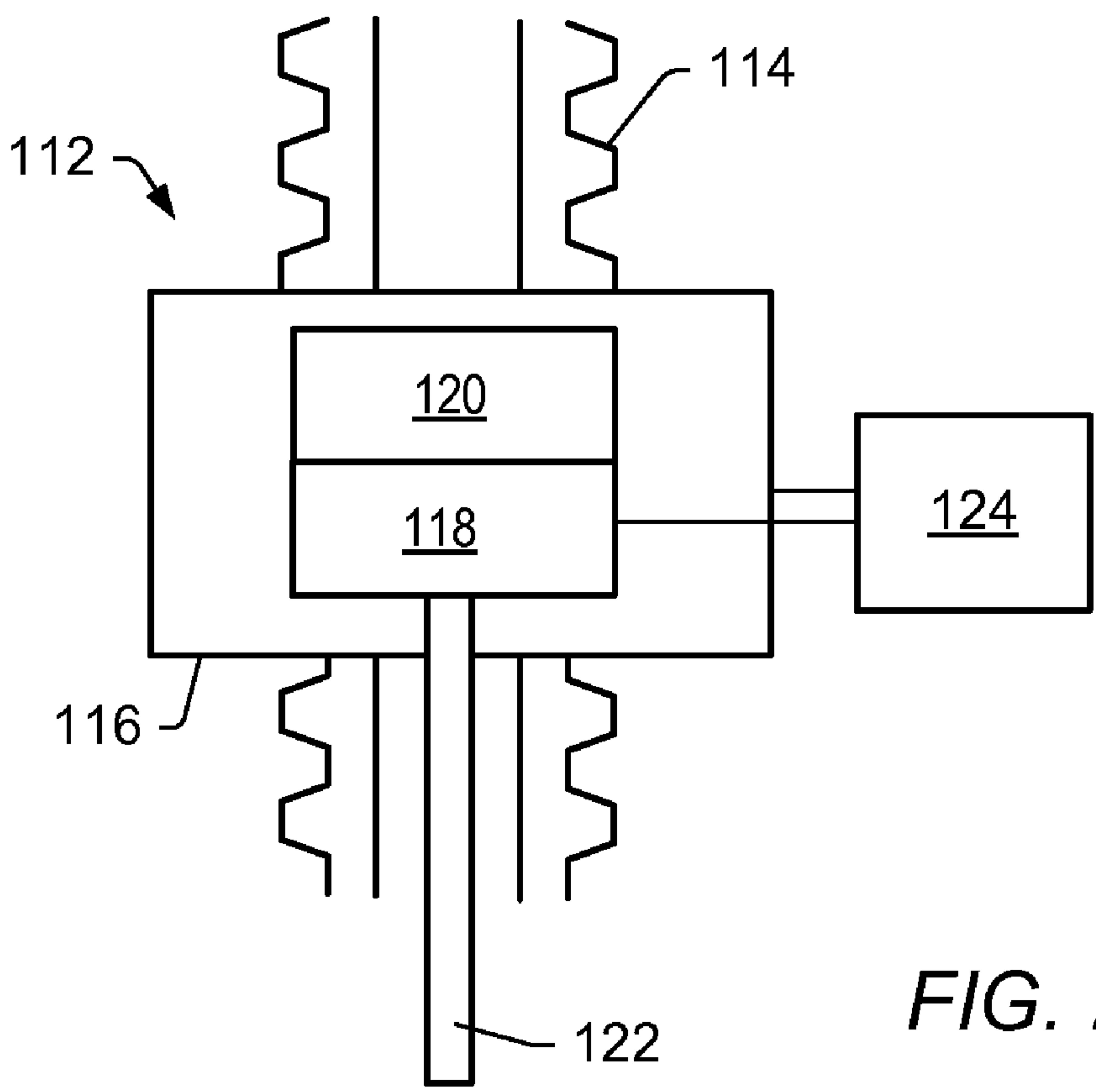

FIG. 2

(57) Abrégé/Abstract:
Systems and methods for forming subsurface wellbores are described. A system may include a rack and pinion a rack and pinion system and an automatic position control system. The rack and pinion includes a chuck drive system configured to operate a

(57) Abrégé(suite)/Abstract(continued):
drilling string. The automatic position control system includes at least one measurement sensor coupled to the rack and pinion system. The automatic position control system is configured to control the rack and pinion system to determine a position of the drilling string.

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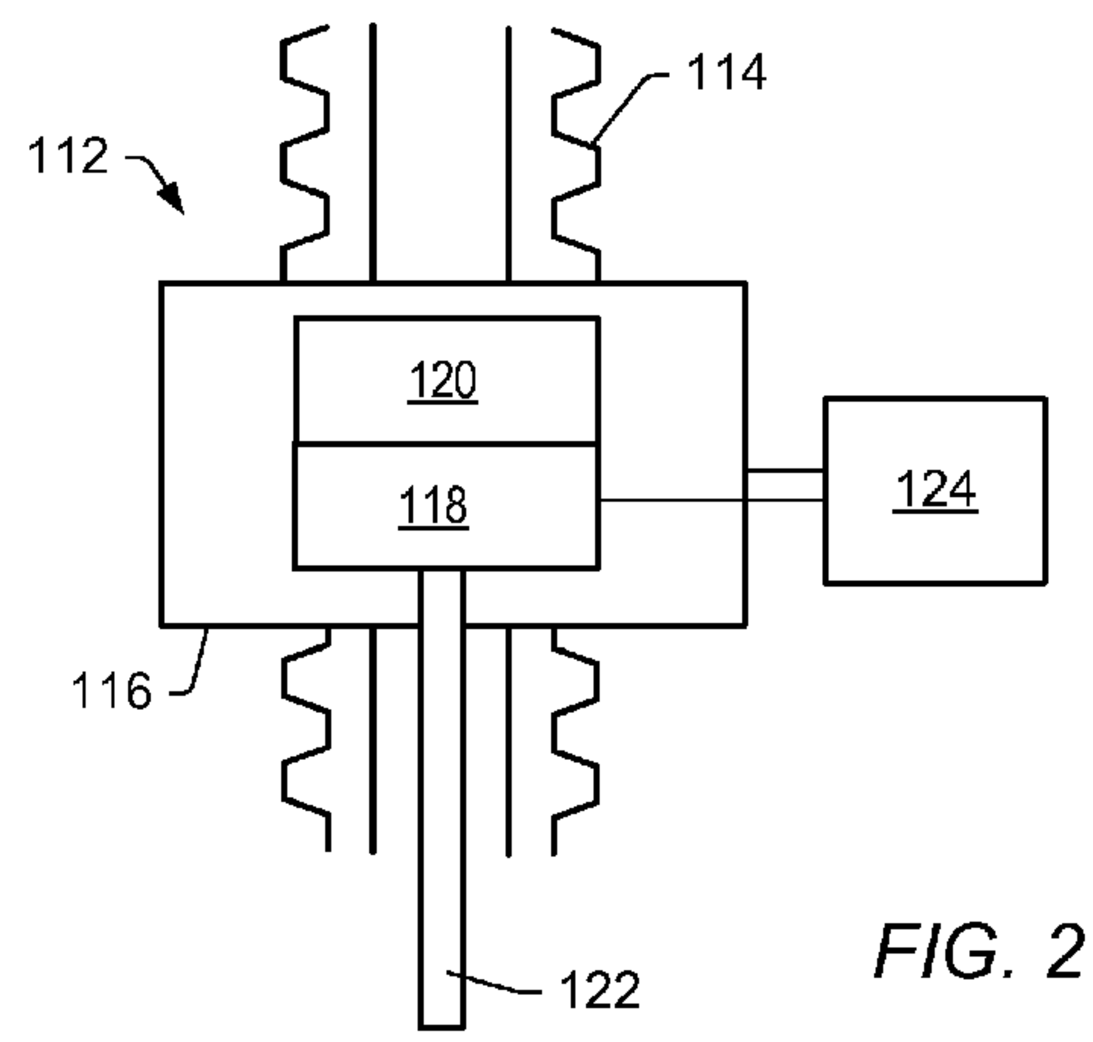

FIG. 2

(57) Abstract: Systems and methods for forming subsurface wellbores are described. A system may include a rack and pinion a rack and pinion system and an automatic position control system. The rack and pinion includes a chuck drive system configured to operate a drilling string. The automatic position control system includes at least one measurement sensor coupled to the rack and pinion system. The automatic position control system is configured to control the rack and pinion system to determine a position of the drilling string.

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SYSTEMS AND METHODS OF FORMING SUBSURFACE WELLBORES

BACKGROUND

1. Field of the Invention

[0001] The present invention relates generally to systems and methods for production of hydrocarbons, hydrogen, and/or other products from various subsurface formations such as hydrocarbon containing formations. The present invention relates in particular to systems and methods of forming subsurface wellbores.

2. Description of Related Art

[0002] Hydrocarbons obtained from subterranean formations are often used as energy resources, as feedstocks, and as consumer products. Concerns over depletion of available hydrocarbon resources and concerns over declining overall quality of produced hydrocarbons have led to development of processes for more efficient recovery, processing and/or use of available hydrocarbon resources. In situ processes may be used to remove hydrocarbon materials from subterranean formations. Chemical and/or physical properties of hydrocarbon material in a subterranean formation may need to be changed to allow hydrocarbon material to be more easily removed from the subterranean formation. The chemical and physical changes may include in situ reactions that produce removable fluids, composition changes, solubility changes, density changes, phase changes, and/or viscosity changes of the hydrocarbon material in the formation. A fluid may be, but is not limited to, a gas, a liquid, an emulsion, a slurry, and/or a stream of solid particles that has flow characteristics similar to liquid flow.

[0003] Heaters may be placed in wellbores to heat a formation during an in situ process. Heat may be applied to the oil shale formation to pyrolyze kerogen in the oil shale formation. The heat may also fracture the formation to increase permeability of the formation. The increased permeability may allow formation fluid to travel to a production well where the fluid is removed from the oil shale formation. A heat source may be used to heat a subterranean formation. Electric heaters may be used to heat the subterranean formation by radiation and/or conduction. An electric heater may resistively heat an element.

[0004] Obtaining permeability in an oil shale formation between injection and production wells tends to be difficult because oil shale is often substantially impermeable. Drilling such wells may be expensive and time consuming. Many methods have attempted to link injection and production wells.

[0005] Wellbores for heater, injection, and/or production wells may be drilled by rotating a drill bit against the formation. The drill bit may be suspended in a borehole by a drill string that extends to the surface. In some cases, the drill bit may be rotated by rotating the drill string at the surface. A drilling fluid may be used to flush the wellbore during drilling. Flushing of the wellbore may remove dirt and/or metal cuttings produced during drilling. In some cases, hydrostatic pressure of the drilling fluid in the wellbore may be maintained at a higher pressure with respect to the formation pore pressure. In other cases, pressure in an open section of the borehole may be maintained below the formation pressure such that formation fluid flows into the wellbore during drilling.

[0006] Sensors may be attached to drilling systems to assist in determining direction, operating parameters, and/or operating conditions during drilling of a wellbore. Using the sensors may decrease the amount of time taken to determine positioning of the drilling systems. For example, U.S. Patent No. 7,093,370 to Hansberry describes a borehole navigation system that can determine position and attitude for any orientation in a borehole utilizing multiple gimbals containing solid state or other gyros and accelerometers that fit within the small diameter of a borehole drill pipe. U.S. Patent Application Publication No. 2009-027041 to Zaeper et al. describes a method of measuring while drilling that includes positioning at least one sensor downhole, and transmitting sensed data while drilling from the at least one sensor to the surface without processing the sensed data downhole.

[0007] As outlined above, there has been a significant amount of effort to develop methods and systems using navigation systems and/or sensors to drill wellbores in hydrocarbon formations. At present, however, there are still many hydrocarbon containing formations where drilling wellbores is difficult, expensive, and/or time consuming. Thus, there is still a need for improved methods and systems of drilling wellbores for production of hydrocarbons, hydrogen, and/or other products from various hydrocarbon containing formations.

SUMMARY

[0008] Embodiments described herein generally relate to systems, methods, and for forming a subsurface wellbore. In certain embodiments, the invention provides one or more systems and one or more methods for treating a subsurface formation.

[0009] The invention, in some embodiments provides, a system for forming a subsurface wellbore, comprising: a rack and pinion system comprising a chuck drive system, wherein chuck drive system is configured to operate a drilling string; and an automatic position control system comprising at least one measurement sensor coupled to the rack and pinion system, wherein the automatic position control system is configured to control the rack and pinion system to determine a position of the drilling string.

[0010] The invention, in some embodiments provides, a method for forming a subsurface wellbore, comprising: receiving position data about a tubular from at least one measurement sensor coupled to an automatic position control system; and controlling a direction of the tubular in a formation using a rack and pinion system based on the position data from the measurement sensor.

[0011] The invention, in some embodiments provides, a system for forming a subsurface wellbore, comprising: a bottom drive system configured to couple to an existing tubular of a drilling string at least partially in the subsurface wellbore and to control a drilling operation in the wellbore, the bottom drive system comprising a circulating sleeve configured to accept a new tubular during the drilling operation; and a top drive system configured to couple with the new tubular and to assume control of the drilling operation when the new tubular is coupled to the existing tubular.

[0012] The invention, in some embodiments provides, a method for adding a new tubular to a drilling string, comprising: coupling a top end of the new tubular to a top drive system; positioning a bottom end of the new tubular in an opening of a circulating sleeve of a bottom drive system while the bottom drive system controls a drilling operation; while the drilling operation continues, coupling the new tubular to an existing tubular to form a coupled tubular; transferring control of the drilling operation from the bottom drive system to the top drive system; while the drilling operation continues, moving the bottom drive system up the coupled tubular towards the top drive system; while the drilling operation continues, coupling the bottom drive system to a top portion of the coupled tubular; transferring control of the drilling operation from the top drive system to the bottom drive system; and disconnecting the top drive system from the coupled tubular.

[0013] In further embodiments, features from specific embodiments may be combined with features from other embodiments. For example, features from one embodiment may be combined with features from any of the other embodiments.

[0014] In further embodiments, additional features may be added to the specific embodiments described herein.

BRIEF DESCRIPTION OF THE DRAWINGS

[0015] Advantages of the present invention may become apparent to those skilled in the art with the benefit of the following detailed description and upon reference to the accompanying drawings.

[0016] FIG. 1 shows a schematic view of an embodiment of a portion of an in situ heat treatment system for treating a hydrocarbon containing formation.

[0017] FIG. 2 depicts a schematic of an embodiment of a rack and pinion drilling system.

[0018] FIGS. 3A through 3D depict schematics of an embodiment for a continuous drilling sequence.

[0019] FIG. 4 depicts a cut-away view of an embodiment of a circulating sleeve of the bottom drive system depicted in FIGS. 3A-3D.

[0020] FIG. 5 depicts a schematic of the valve system of the circulating sleeve of the bottom drive system depicted in FIGS. 3A-3D.

[0021] While the invention is susceptible to various modifications and alternative forms, specific embodiments thereof are shown by way of example in the drawings and may herein be described in detail. The drawings may not be to scale. It should be understood, however, that the drawings and detailed description thereto are not intended to limit the invention to the particular form disclosed, but on the contrary, the intention is to cover all modifications, equivalents and alternatives falling within the spirit and scope of the present invention as defined by the appended claims.

[0022] DETAILED DESCRIPTION

[0023] The following description generally relates to systems and methods for forming wellbores in subsurface formations. Use of the wellbores for treating hydrocarbons in the formations to yield hydrocarbon products, hydrogen, and other products is described herein.

[0024] "API gravity" refers to API gravity at 15.5 °C (60 °F). API gravity is as determined by ASTM Method D6822 or ASTM Method D1298.

[0025] "Condensable hydrocarbons" are hydrocarbons that condense at 25 °C and one atmosphere absolute pressure. Condensable hydrocarbons may include a mixture of hydrocarbons having carbon numbers greater than 4. "Non-condensable hydrocarbons" are hydrocarbons that do not condense at 25 °C and one atmosphere absolute pressure. Non-condensable hydrocarbons may include hydrocarbons having carbon numbers less than 5.

[0026] "Fluid pressure" is a pressure generated by a fluid in a formation. "Lithostatic pressure" (sometimes referred to as "lithostatic stress") is a pressure in a formation equal to a weight per unit area of an overlying rock mass. "Hydrostatic pressure" is a pressure in a formation exerted by a column of water.

[0027] A "formation" includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. "Hydrocarbon layers" refer to layers in the formation that contain hydrocarbons. The hydrocarbon layers may contain non-hydrocarbon material and hydrocarbon material. The "overburden" and/or the "underburden" include one or more different types of impermeable materials. For example, the overburden and/or underburden may include rock, shale, mudstone, or wet/tight carbonate. In some embodiments of in situ heat treatment processes, the overburden and/or the underburden may include a hydrocarbon containing layer or hydrocarbon containing layers that are relatively impermeable and are not subjected to temperatures during in situ heat treatment processing that result in significant characteristic changes of the hydrocarbon containing layers of the overburden and/or the underburden. For example, the underburden may contain shale or mudstone, but the underburden is not allowed to heat to pyrolysis temperatures during the in situ heat treatment process. In some cases, the overburden and/or the underburden may be somewhat permeable.

[0028] "Formation fluids" refer to fluids present in a formation and may include pyrolyzation fluid, synthesis gas, mobilized hydrocarbons, and water (steam). Formation fluids may include hydrocarbon fluids as well as non-hydrocarbon fluids. The term "mobilized fluid" refers to fluids in a hydrocarbon containing formation that are able to flow as a result of thermal treatment of the formation. "Produced fluids" refer to fluids removed from the formation.

[0029] A "heat source" is any system for providing heat to at least a portion of a formation substantially by conductive and/or radiative heat transfer. For example, a heat source may include electrically conducting materials and/or electric heaters such as an insulated conductor, an elongated member, and/or a conductor disposed in a conduit. A heat source may also include systems that generate heat by burning a fuel external to or in a formation. The systems may be surface burners, downhole gas burners, flameless distributed combustors, and natural distributed combustors. In some embodiments, heat provided to or generated in one or more heat sources may be supplied by other sources of energy. The other sources of energy may directly heat a formation, or the energy may be applied to a transfer medium that directly or indirectly heats the formation. It is to be understood that one or more heat sources that are applying heat to a formation may use different sources of energy. Thus, for example, for a given formation some heat sources may supply heat from electrically conducting materials, electric resistance heaters, some heat sources may provide heat from combustion, and some heat sources may provide heat from one or more other energy sources (for example, chemical reactions, solar energy, wind energy, biomass, or other sources of renewable energy). A chemical reaction may include an exothermic reaction (for example, an oxidation reaction). A heat source may also include a electrically conducting materials and/or a heater that provides heat to a zone proximate and/or surrounding a heating location such as a heater well.

[0030] A "heater" is any system or heat source for generating heat in a well or a near wellbore region. Heaters may be, but are not limited to, electric heaters, burners, combustors that react with material in or produced from a formation, and/or combinations thereof.

[0031] "Heavy hydrocarbons" are viscous hydrocarbon fluids. Heavy hydrocarbons may include highly viscous hydrocarbon fluids such as heavy oil, tar, and/or asphalt. Heavy hydrocarbons may include carbon and hydrogen, as well as smaller concentrations of sulfur, oxygen, and nitrogen. Additional elements may also be present in heavy hydrocarbons in trace amounts. Heavy hydrocarbons may be classified by API gravity. Heavy hydrocarbons generally have an API gravity below about 20°. Heavy oil, for example, generally has an API gravity of about 10-20°, whereas tar generally has an API gravity below about 10°. The viscosity of heavy hydrocarbons is generally greater than about 100 centipoise at 15 °C. Heavy hydrocarbons may include aromatics or other complex ring hydrocarbons.

[0032] Heavy hydrocarbons may be found in a relatively permeable formation. The relatively permeable formation may include heavy hydrocarbons entrained in, for example, sand or carbonate. "Relatively permeable" is defined, with respect to formations or portions thereof, as an average permeability of 10 millidarcy or more (for example, 10 or 100 millidarcy). "Relatively low permeability" is defined, with respect to formations or portions thereof, as an average permeability of less than about 10 millidarcy. One darcy is equal to about 0.99 square micrometers. An impermeable layer generally has a permeability of less than about 0.1 millidarcy.

[0033] Certain types of formations that include heavy hydrocarbons may also include, but are not limited to, natural mineral waxes, or natural asphaltites. "Natural mineral waxes" typically occur in substantially tubular veins that may be several meters wide, several kilometers long, and hundreds of meters deep. "Natural asphaltites" include solid hydrocarbons of an aromatic composition and typically occur in large veins. In situ recovery of hydrocarbons from formations such as natural mineral waxes and natural asphaltites may include melting to form liquid hydrocarbons and/or solution mining of hydrocarbons from the formations.

[0034] "Hydrocarbons" are generally defined as molecules formed primarily by carbon and hydrogen atoms. Hydrocarbons may also include other elements such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur. Hydrocarbons may be, but are not limited to, kerogen, bitumen, pyrobitumen, oils, natural mineral waxes, and asphaltites. Hydrocarbons may be located in or adjacent to mineral matrices in the earth. Matrices may include, but are not limited to, sedimentary rock, sands, silicilytes, carbonates, diatomites, and other porous media. "Hydrocarbon fluids" are fluids that include hydrocarbons. Hydrocarbon fluids may include, entrain, or be entrained in non-hydrocarbon fluids such as hydrogen, nitrogen, carbon monoxide, carbon dioxide, hydrogen sulfide, water, and ammonia.

[0035] An "in situ conversion process" refers to a process of heating a hydrocarbon containing formation from heat sources to raise the temperature of at least a portion of the formation above a pyrolysis temperature so that pyrolyzation fluid is produced in the formation.

[0036] An "in situ heat treatment process" refers to a process of heating a hydrocarbon containing formation with heat sources to raise the temperature of at least a portion of the formation above a temperature that results in mobilized fluid, visbreaking, and/or pyrolysis of hydrocarbon containing material so that mobilized fluids, visbroken fluids, and/or pyrolyzation fluids are produced in the formation.

[0037] "Pyrolysis" is the breaking of chemical bonds due to the application of heat. For example, pyrolysis may include transforming a compound into one or more other substances by heat alone. Heat may be transferred to a section of the formation to cause pyrolysis.

[0038] "Pyrolyzation fluids" or "pyrolysis products" refers to fluid produced substantially during pyrolysis of hydrocarbons. Fluid produced by pyrolysis reactions may mix with other fluids in a formation. The mixture would be considered pyrolyzation fluid or pyrolyzation product. As used herein, "pyrolysis zone" refers to a volume of a formation (for example, a relatively permeable formation such as a tar sands formation) that is reacted or reacting to form a pyrolyzation fluid.

[0039] A "tar sands formation" is a formation in which hydrocarbons are predominantly present in the form of heavy hydrocarbons and/or tar entrained in a mineral grain framework or other host lithology (for example, sand or carbonate). Examples of tar sands formations include formations such as the Athabasca formation, the Grosmont formation, and the Peace River formation, all three in Alberta, Canada; and the Faja formation in the Orinoco belt in Venezuela.

[0040] A "u-shaped wellbore" refers to a wellbore that extends from a first opening in the formation, through at least a portion of the formation, and out through a second opening in the formation. In this context, the wellbore may be only roughly in the shape of a "v" or "u", with the understanding that the "legs" of the "u" do not need to be parallel to each other, or perpendicular to the "bottom" of the "u" for the wellbore to be considered "u-shaped".

[0041] The term "wellbore" refers to a hole in a formation made by drilling or insertion of a conduit into the formation. A wellbore may have a substantially circular cross section, or another cross-sectional shape. As used herein, the terms "well" and "opening," when referring to an opening in the formation may be used interchangeably with the term "wellbore."

[0042] A formation may be treated in various ways to produce many different products. Different stages or processes may be used to treat the formation during an in situ heat treatment process. In some embodiments, one or more sections of the formation are solution mined to remove soluble minerals from the sections. Solution mining minerals may be performed before, during, and/or after the in situ heat treatment process. In some embodiments, the average temperature of one or more sections being solution mined may be maintained below about 120 °C.

[0043] In some embodiments, one or more sections of the formation are heated to remove water from the sections and/or to remove methane and other volatile hydrocarbons from the sections. In some embodiments, the average temperature may be raised from ambient temperature to temperatures below about 220 °C during removal of water and volatile hydrocarbons.

[0044] In some embodiments, one or more sections of the formation are heated to temperatures that allow for movement and/or visbreaking of hydrocarbons in the formation. In some embodiments, the average temperature of one or more sections of the formation are raised to mobilization temperatures of hydrocarbons in the sections (for example, to temperatures ranging from 100 °C to 250 °C, from 120 °C to 240 °C, or from 150 °C to 230 °C).

[0045] In some embodiments, one or more sections are heated to temperatures that allow for pyrolysis reactions in the formation. In some embodiments, the average temperature of one or more sections of the formation may be raised to pyrolysis temperatures of hydrocarbons in the sections (for example, temperatures ranging from 230 °C to 900 °C, from 240 °C to 400 °C or from 250 °C to 350 °C).

[0046] Heating the hydrocarbon containing formation with a plurality of heat sources may establish thermal gradients around the heat sources that raise the temperature of hydrocarbons in the formation to desired temperatures at desired heating rates. The rate of temperature increase through mobilization temperature range and/or pyrolysis temperature range for desired products may affect the quality and quantity of the formation fluids produced from the hydrocarbon containing formation. Slowly raising the temperature of the formation through the mobilization temperature range and/or pyrolysis temperature range may allow for the production of high quality, high API gravity hydrocarbons from the formation. Slowly raising the temperature of the formation through the mobilization temperature range and/or pyrolysis temperature range may allow for the removal of a large amount of the hydrocarbons present in the formation as hydrocarbon product.

[0047] In some in situ heat treatment embodiments, a portion of the formation is heated to a desired temperature instead of slowly heating the temperature through a temperature range. In some embodiments, the desired temperature is 300 °C, 325 °C, or 350 °C. Other temperatures may be selected as the desired temperature.

[0048] Superposition of heat from heat sources allows the desired temperature to be relatively quickly and efficiently established in the formation. Energy input into the formation from the heat sources may be adjusted to maintain the temperature in the formation substantially at a desired temperature.

[0049] Mobilization and/or pyrolysis products may be produced from the formation through production wells. In some embodiments, the average temperature of one or more sections is raised to mobilization temperatures and hydrocarbons are produced from the production wells. The average temperature of one or more of the sections may be raised to pyrolysis temperatures after production due to mobilization decreases below a selected value. In some embodiments, the average temperature of one or more sections may be raised to pyrolysis temperatures without significant production before reaching pyrolysis temperatures. Formation fluids including pyrolysis products may be produced through the production wells.

[0050] In some embodiments, the average temperature of one or more sections may be raised to temperatures sufficient to allow synthesis gas production after mobilization and/or pyrolysis. In some embodiments, hydrocarbons may be raised to temperatures sufficient to allow synthesis gas production without significant production before reaching the temperatures sufficient to allow synthesis gas production. For example, synthesis gas may be produced in a temperature range from about 400 °C to about 1200 °C, about 500 °C to about 1100 °C, or about 550 °C to about 1000 °C. A synthesis gas generating fluid (for example, steam and/or water) may be introduced into the sections to generate synthesis gas. Synthesis gas may be produced from production wells.

[0051] Solution mining, removal of volatile hydrocarbons and water, mobilizing hydrocarbons, pyrolyzing hydrocarbons, generating synthesis gas, and/or other processes may be performed during the in situ heat treatment process. In some embodiments, some processes may be performed after the in situ heat treatment process. Such processes may include, but are not limited to, recovering heat from treated sections, storing fluids (for example, water and/or hydrocarbons) in previously treated sections, and/or sequestering carbon dioxide in previously treated sections.

[0052] FIG. 1 depicts a schematic view of an embodiment of a portion of the in situ heat treatment system for treating the hydrocarbon containing formation. The in situ heat treatment system may include barrier wells 100. Barrier wells are used to form a barrier around a treatment area. The barrier inhibits fluid flow into and/or out of the treatment area. Barrier wells include, but are not limited to, dewatering wells, vacuum wells, capture wells, injection wells, grout wells, freeze wells, or combinations thereof. In some embodiments, barrier wells 100 are dewatering wells. Dewatering wells may remove liquid water and/or inhibit liquid water from entering a portion of the formation to be heated, or to the formation being heated. In the embodiment depicted in FIG. 1, the barrier wells 100 are shown extending only along one side of heat sources 102, but the barrier wells typically encircle all heat sources 102 used, or to be used, to heat a treatment area of the formation.

[0053] Heat sources 102 are placed in at least a portion of the formation. Heat sources 102 may include electrically conducting materials. In some embodiments, heaters such as insulated conductors, conductor-in-conduit heaters, surface burners, flameless distributed combustors, and/or natural distributed combustors. Heat sources 102 may also include other types of heaters. Heat sources 102 provide heat to at least a portion of the formation to heat hydrocarbons in the formation. Energy may be supplied to heat sources 102 through supply lines 104. Supply lines 104 may be structurally different depending on the type of heat source or heat sources used to heat the formation. Supply lines 104 for heat sources may transmit electricity for electrically conducting materials and/or electric heaters, may transport fuel for combustors, or may transport heat exchange fluid that is circulated in the formation. In some embodiments, electricity for an in situ heat treatment process may be provided by a nuclear power plant or nuclear power plants. The use of nuclear power may allow for reduction or elimination of carbon dioxide emissions from the in situ heat treatment process.

[0054] When the formation is heated, the heat input into the formation may cause expansion of the formation and geomechanical motion. The heat sources may be turned on before, at the same time, or during a dewatering process. Computer simulations may model formation response to heating. The computer simulations may be used to develop a pattern and time sequence for activating heat sources in the formation so that geomechanical motion of the formation does not adversely affect the functionality of heat sources, production wells, and other equipment in the formation.

[0055] Heating the formation may cause an increase in permeability and/or porosity of the formation. Increases in permeability and/or porosity may result from a reduction of mass in the formation due to vaporization and removal of water, removal of hydrocarbons, and/or creation of fractures. Fluid may flow more easily in the heated portion of the formation because of the increased permeability and/or porosity of the formation. Fluid in the heated portion of the formation may move a considerable distance through the formation because of the increased permeability and/or porosity. The considerable distance may be over 1000 m depending on various factors, such as permeability of the formation, properties of the fluid, temperature of the formation, and pressure gradient allowing movement of the fluid. The ability of fluid to travel considerable distance in the formation allows production wells 106 to be spaced relatively far apart in the formation.

[0056] Production wells 106 are used to remove formation fluid from the formation. In some embodiments, production well 106 includes a heat source. The heat source in the production well may heat one or more portions of the formation at or near the production well. In some in situ heat treatment process embodiments, the amount of heat supplied to the formation from the production well per meter of the production well is less than the amount of heat applied to the formation from a heat source that heats the formation per meter of the heat source. Heat applied to the formation from the production well may increase formation permeability adjacent to the production well by vaporizing and removing liquid phase fluid adjacent to the production well and/or by increasing the permeability of the formation adjacent to the production well by formation of macro and/or micro fractures.

[0057] More than one heat source may be positioned in the production well. A heat source in a lower portion of the production well may be turned off when superposition of heat from adjacent heat sources heats the formation sufficiently to counteract benefits provided by heating the formation with the production well. In some embodiments, the heat source in an upper portion of the production well may remain on after the heat source in the lower portion of the production well is deactivated. The heat source in the upper portion of the well may inhibit condensation and reflux of formation fluid.

[0058] In some embodiments, the heat source in production well 106 allows for vapor phase removal of formation fluids from the formation. Providing heating at or through the production well may: (1) inhibit condensation and/or refluxing of production fluid when such production fluid is moving in the production well proximate the overburden, (2) increase heat input into the formation, (3) increase production rate from the production well as compared to a production well without a heat source, (4) inhibit condensation of high carbon number compounds (C_6 hydrocarbons and above) in the production well, and/or (5) increase formation permeability at or proximate the production well.

[0059] Subsurface pressure in the formation may correspond to the fluid pressure generated in the formation. As temperatures in the heated portion of the formation increase, the pressure in the heated portion may increase as a result of thermal expansion of in situ fluids, increased fluid generation and vaporization of water. Controlling rate of fluid removal from the formation may allow for control of pressure in the formation. Pressure in the formation may be determined at a number of different locations, such as near or at production wells, near or at heat sources, or at monitor wells.

[0060] In some hydrocarbon containing formations, production of hydrocarbons from the formation is inhibited until at least some hydrocarbons in the formation have been mobilized and/or pyrolyzed. Formation fluid may be produced from the formation when the formation fluid is of a selected quality. In some embodiments, the selected quality includes an API gravity of at least about 20°, 30°, or 40°. Inhibiting production until at least some hydrocarbons are mobilized and/or pyrolyzed may increase conversion of heavy hydrocarbons to light hydrocarbons. Inhibiting initial production may minimize the production of heavy hydrocarbons from the formation. Production of substantial amounts of heavy hydrocarbons may require expensive equipment and/or reduce the life of production equipment.

[0061] In some hydrocarbon containing formations, hydrocarbons in the formation may be heated to mobilization and/or pyrolysis temperatures before substantial permeability has been generated in the heated portion of the formation. An initial lack of permeability may inhibit the transport of generated fluids to production wells 106. During initial heating, fluid pressure in the formation may increase proximate heat sources 102. The increased fluid pressure may be released, monitored, altered, and/or controlled through one or more heat sources 102. For example, selected heat sources 102 or separate pressure relief wells may include pressure relief valves that allow for removal of some fluid from the formation.

[0062] In some embodiments, pressure generated by expansion of mobilized fluids, pyrolysis fluids or other fluids generated in the formation may be allowed to increase although an open path to production wells 106 or any other pressure sink may not yet exist in the formation. The fluid pressure may be allowed to increase towards a lithostatic pressure. Fractures in the hydrocarbon containing formation may form when the fluid approaches the lithostatic pressure. For example, fractures may form from heat sources 102 to production wells 106 in the heated portion of the formation. The generation of fractures in the heated portion may relieve some of the pressure in the portion. Pressure in the formation may have to be maintained below a selected pressure to inhibit unwanted production, fracturing of the overburden or underburden, and/or coking of hydrocarbons in the formation.

[0063] After mobilization and/or pyrolysis temperatures are reached and production from the formation is allowed, pressure in the formation may be varied to alter and/or control a composition of formation fluid produced, to control a percentage of condensable fluid as compared to non-condensable fluid in the formation fluid, and/or to control an API gravity of formation fluid being produced. For example, decreasing pressure may result in production of a larger condensable fluid component. The condensable fluid component may contain a larger percentage of olefins.

[0064] In some in situ heat treatment process embodiments, pressure in the formation may be maintained high enough to promote production of formation fluid with an API gravity of greater than 20°. Maintaining increased pressure in the formation may inhibit formation subsidence during in situ heat treatment. Maintaining increased pressure may reduce or eliminate the need to compress formation fluids at the surface to transport the fluids in collection conduits to treatment facilities.

[0065] Maintaining increased pressure in a heated portion of the formation may surprisingly allow for production of large quantities of hydrocarbons of increased quality and of relatively low molecular weight. Pressure may be maintained so that formation fluid produced has a minimal amount of compounds above a selected carbon number. The selected carbon number may be at most 25, at most 20, at most 12, or at most 8. Some high carbon number compounds may be entrained in vapor in the formation and may be removed from the formation with the vapor. Maintaining increased pressure in the formation may inhibit entrainment of high carbon number compounds and/or multi-ring hydrocarbon compounds in the vapor. High carbon number compounds and/or multi-ring hydrocarbon compounds may remain in a liquid phase in the formation for significant time periods. The significant time periods may provide sufficient time for the compounds to pyrolyze to form lower carbon number compounds.

[0066] Generation of relatively low molecular weight hydrocarbons is believed to be due, in part, to autogenous generation and reaction of hydrogen in a portion of the hydrocarbon containing formation. For example, maintaining an increased pressure may force hydrogen generated during pyrolysis into the liquid phase within the formation. Heating the portion to a temperature in a pyrolysis temperature range may pyrolyze hydrocarbons in the formation to generate liquid phase pyrolyzation fluids. The generated liquid phase pyrolyzation fluids components may include double bonds and/or radicals. Hydrogen (H_2) in the liquid phase may reduce double bonds of the generated pyrolyzation fluids, thereby reducing a potential for polymerization or formation of long chain compounds from the generated pyrolyzation fluids. In addition, H_2 may also neutralize radicals in the generated pyrolyzation fluids. H_2 in the liquid phase may inhibit the generated pyrolyzation fluids from reacting with each other and/or with other compounds in the formation.

[0067] Formation fluid produced from production wells 106 may be transported through collection piping 108 to treatment facilities 110. Formation fluids may also be produced from heat sources 102. For example, fluid may be produced from heat sources 102 to control pressure in the formation adjacent to the heat sources. Fluid produced from heat sources 102 may be transported through tubing or piping to collection piping 108 or the produced fluid may be transported through tubing or piping directly to treatment facilities 110. Treatment facilities 110 may include separation units, reaction units, upgrading units, fuel cells, turbines, storage vessels, and/or other systems and units for processing produced formation fluids. The treatment facilities may form transportation fuel from at least a portion of the hydrocarbons produced from the formation.

[0068] Many wells are needed for treating the hydrocarbon formation using the in situ heat treatment process. In some embodiments, vertical or substantially vertical wells are formed in the formation. In some embodiments, horizontal or U-shaped wells are formed in the formation. In some embodiments, combinations of horizontal and vertical wells are formed in the formation.

[0069] Accuracy and efficiency in forming wellbores in subsurface formations may be affected by the density and quality of directional data during drilling. The quality of directional data may be diminished by vibrations and angular accelerations during rotary drilling, especially during rotary drilling segments using slide mode drilling.

[0070] In some embodiments, an automatic position control system in combination with a rack and pinion drilling system may be used for forming wellbores in a formation. Use of an automatic position control and/or measurement system in combination with a rack and pinion drilling system may allow wellbores to be drilled more accurately than drilling using manual positioning and calibration. For example, the automatic position system may be continuously and/or semi-continuously calibrated during drilling. FIG. 2 depicts a schematic of a portion of a system including a rack and pinion drive system. Rack and pinion drive system 112 includes, but is not limited to, rack 114, carriage 116, chuck drive system 118, and circulating sleeve 120. Chuck drive system 118 may hold tubular 122. Push/pull capacity of a rack and pinion type system may allow enough force (for example, about 5 tons) to push tubulars into wellbores so that rotation of the tubulars is not necessary. A rack and pinion system may apply downward force on the drill bit. The force applied to the drill bit may be independent of the weight of the drilling string (tubulars) and/or collars. In certain embodiments, collar size and weight is reduced because the weight of the collars is not needed to enable drilling operations. Drilling wellbores with long horizontal portions may be performed using rack and pinion drilling systems because of the ability of the drilling systems to apply force to the drilling bit independent of the vertical length of drill string available to provide weight on bit.

[0071] Rack and pinion drive system 112 may be coupled to automatic position control system 124. Automatic position control system 124 may include, but is not limited to, rotary steerable systems, dual motor rotary steerable systems, and/or hole measurement systems. In some embodiments, a measurement system includes one or more sensors, including, but not limited to, magnetic ranging sensors, non-rotating sensors, and/or canted accelerometers. In some embodiments, one or more heaters are included in one or more tubulars of the rack and pinion drive system. In some embodiments, hole measurement systems are positioned in the heaters.

[0072] In some embodiments, a hole measuring system includes one or more canted accelerometers. Use of canted accelerometers may allow for surveying of a shallow portion of the formation. For example, shallow portions of the formation may have steel casing strings from drilling operations and/or other wells. The steel casings may affect the use of magnetic survey tools in determining the direction of deflection incurred during drilling. Canted accelerometers may be positioned in a bottom hole assembly of a drilling system (for example, a rack and pinion drilling system) with the surface as reference of tubular rotational position. Positioning the canted accelerometers in a bottom hole assembly may allow accurate measurement of inclination and direction of a hole regardless of the influence of nearby magnetic interference sources (for example, casing strings). In some embodiments, the relative rotational position of the tubular is monitored by measuring and tracking incremental rotation of the shaft. By monitoring the relative rotation of tubulars added to existing tubulars, more accurate positioning of tubulars may be achieved. Such monitoring may allow tubulars to be added in a continuous manner.

[0073] In some embodiments, a method of drilling using a rack and pinion system includes continuous downhole measurement. A measurement system may be operated using a predetermined and constant current signal. Distance and direction are calculated continuously downhole. The results of the calculations are filtered and averaged. A best estimate final distance and direction is reported to the surface. When received on the surface, the known along-hole depth and tubular location may be combined with the calculated distance and direction to calculate X, Y and Z position data.

[0074] During drilling with jointed pipes, the time taken to shut down circulation, add the next pipe, re-establish circulation, and continuation of hole making may require a substantial amount of time, particularly when using two-phase circulation systems. Handling tubulars (for example, pipes) has historically been a large safety risk where manual handling techniques have been used. Coiled tubing drilling has had some success in eliminating the need for making connections and manual tubular handling; however, the inability to rotate and the limitations on practical coil diameters may limit the extent to which it can be used.

[0075] In some embodiments, a drilling sequence is used in which tubulars are added to a string without interrupting the drilling process. The tubulars may include jointed connections that allow the tubulars to be connected under pressure. Such a sequence may allow continuous rotary drilling with large diameter tubulars. The tubulars may include heaters and/or automatic position control systems described herein.

[0076] A continuous rotary drilling system may include a drilling platform, which includes, but is not limited to, one or more platforms, a top drive system, and a bottom drive system. The platform may include a rack to allow multiple independent traversing of components. The top drive system may include an extended drive sub (for example, an extended drive system manufactured by American Augers, West Salem, Ohio, U.S.A.). The top drive system may be, for example, a rotary drive system or a rack and pinion drive system. The bottom drive system may include a chuck drive system and a hydraulic system. The bottom drive system may operate in a similar manner to a rack and pinion drilling system (for example, the rack and pinion system described in FIG. 2). Bottom drive system and top drive system may alternate control of the drilling operation. The chuck drive system may be mounted on a separate carriage. The hydraulic system may include, but is not limited to, one or more motors and a circulating sleeve. The circulating sleeve may allow circulation between tubulars and the annulus. The circulating sleeve may be used to open or shut off production from various intervals in the well. In some embodiments, a system includes a tubular handling system. A tubular handling system may be automated, manually operated, or a combination thereof.

[0077] In some embodiments, a method using a continuous rotary drilling system includes adding a new tubular to an existing tubular coupled to a bottom drive system to form an extended tubular. During drilling while the bottom drive system controls the drilling operation, a new tubular may be positioned in an opening of the circulating sleeve of the bottom drive system. The new tubular may be coupled to a top drive system. The circulating sleeve of the bottom drive system may allow fluid to flow around the two tubulars. The fluid pressure in the circulating sleeve may be at pressures of up to about 13.8 MPa (2000 psi). The circulation sleeve may include one or more valves (for example, UBD circulation or check valves) that facilitate change and/or flow of circulation. The use of valves may assist in maintaining pressure in the system. The pressure applied to the two tubulars in the circulating sleeve may couple (for example, pressure-fit) the two tubulars to form a coupled tubular without interruption of the drilling process. During and/or after coupling the tubulars together, control of the drilling operation may be transferred from the bottom drive system to the top drive system. Transfer of the drilling operation to the top drive system may allow the bottom drive system to travel up the coupled tubular towards the top drive system without interruption of the drilling process. The bottom drive system may attach to a drive sub of the top drive system and the control of the drilling operation may be transferred from the top drive system to the bottom drive system without interruption of the drilling process. Once drilling control is transferred to the bottom drive system, the top drive system may disconnect from the tubular. The top drive system may then connect to the top of another tubular to continue the process.

[0078] FIGS. 3A-3D depict a schematic of an embodiment of a continuous drilling sequence. FIG. 4 depicts a cut-away view of an embodiment of a circulating sleeve of the bottom drive system depicted in FIGS. 3A-3D. FIG. 5 depicts a schematic of the valve system of the circulating sleeve of the bottom drive system depicted in FIGS. 3A-3D. Referring to FIGS. 3A-3D, the continuous drilling sequence includes bottom drive system 112, tubular handling system 128, and top drive system 130. Top drive system 130 includes top circulating sleeve 132 and drive sub 134. Bottom drive system 112 includes bottom circulating sleeve 120 and chuck 118. In some embodiments, the chuck may be on a separate carriage system. As shown in FIGS. 3A-3D, top drive system 130 is at reference line Y and bottom drive system 112 is at reference line Z. It will be understood that reference lines Y and Z are shown for illustrative purposes only, and the heights of the drive systems at various stages in the sequence may be different than those depicted in FIGS. 3A-3D.

[0079] As shown in FIG. 3A, existing tubular 122 is coupled to chuck 118 of bottom drive system 112. Bottom drive system controls the drilling operation that inserts existing tubular 122 in a subsurface formation. During the drilling operation, fluid may enter bottom circulating sleeve 120 through port 136 and flow around existing tubular 122. Fluid may remove heat away from chuck 118 and/or existing tubular 122. Bottom circulating sleeve 120 may include side valve 138 (shown in FIG. 5). Side valve 138 may be a check valve incorporated into a side entry flow and check valve port. Use of side valve 138 and/or top valve 140 (shown in FIG. 5) may facilitate change of circulation entry points and creation of a pressurized system (for example, pressures up to 13.8 MPa).

[0080] As chuck 118 of bottom drive system 112 continues to control drilling using existing tubular 122, new tubular 142 may be aligned with bottom drive system 112 using tubular handling system 128. Once in position, top drive system 130 may be connected to a top end (for example, a box end) of new tubular 142. As shown in FIG. 3B, top drive system 130 lowers and positions or drops a bottom end of new tubular 142 in opening 144 (depicted in FIG. 4) of circulating sleeve 120 of bottom drive system 112. In some embodiments, bottom circulating sleeve 120 includes side valve 138 (shown in FIG. 5) at port 136 and top entry valve 140 at opening 144 (shown in FIG. 5). Regulation of fluid flow through bottom circulating sleeve 120 using valves 138, 140 may control the pressure in the circulating sleeve. In some embodiments, bottom circulating sleeve 120 may include, and/or operate in conjunction with, one or more valves.

[0081] Opening 144 may include one or more tooljoints 148 (see FIG. 4). Tooljoints 148 may guide entry of new tubular 142 in an inner section of circulating sleeve. Since circulating sleeve 120 is pressurized, tooljoints 148 may allow equalization of pressure in the sleeve. Equalization of the pressure facilitates moving new tubular 142 past top entry valve 140 and into bottom circulating sleeve 120.

[0082] Once new tubular 142 is in the chamber of bottom circulating sleeve 120, circulation changes to top drive system 130 and fluid flows through port 146 into top circulating sleeve 132 of top drive system 130. In the chamber of bottom circulating sleeve 120, new tubular 142 and existing tubular 122 are coupled to form coupled tubular 150. Coupled tubular 150 includes new tubular 142 and existing tubular 122. After forming coupled tubular 150, chuck 118 of bottom drive system 112 may disconnect from coupled tubular 150, thus relinquishing control of the drilling process to top drive system 130.

[0083] While top drive system 130 controls the drilling process, bottom drive system 112 may be actuated to travel upward (see arrow shown in FIG. 3C) toward top drive system 130 along the length of coupled tubular 150. As bottom circulating system sleeve 120 of bottom drive system 112 comes into proximity with drive sub 134 of top drive system 130, fluid from top drive system 130 may be flowing from top circulating sleeve 132 of top drive system 130 through top valve 140 (shown in FIG. 5). Bottom circulating sleeve 120 may be pressurized and side valve 138 (shown in FIG. 5) may open to provide flow. Top valve 140 (shown in FIG. 5) may shut and/or partially close as side valve 138 opens to provide flow to top circulating sleeve 132. Circulation may be slowed or discontinued through top drive system 130. As circulation is stopped through top drive system 130, top valve 140 may close completely and all fluid may be furnished through side valve 138 from port 136. When bottom drive system 112 reaches the top of coupled tubular 150, bottom drive system 112 may engage drive sub 134. Coupled tubular 150 may disengage from drive sub 134 and engage with chuck 118 while bottom drive system 112 resumes control of the drilling operation. Chuck 118 transfers force to couple tubular 150 to continue the drilling process.

[0084] Once disengaged from coupled tubular 150, top drive system 130 may be raised (see up arrow) relative to bottom drive system 112 (for example, until top drive system 130 reaches reference line Y as shown in FIG. 3D). Bottom drive system 112 may be lowered to push coupled tubular 150 downward into the formation (see down arrows in FIG 3D). Bottom drive system 112 may continue to be lowered (for example, until bottom drive system 112 has returned to reference line Z). The sequence described above may be repeated any number of times so as to maintain continuous drilling operations.

[0085] Further modifications and alternative embodiments of various aspects of the invention may be apparent to those skilled in the art in view of this description. Accordingly, this description is to be construed as illustrative only and is for the purpose of teaching those skilled in the art the general manner of carrying out the invention. It is to be understood that the forms of the invention shown and described herein are to be taken as the presently preferred embodiments. Elements and materials may be substituted for those illustrated and described herein, parts and processes may be reversed, and certain features of the invention may be utilized independently, all as would be apparent to one skilled in the art after having the benefit of this description of the invention. Changes may be made in the elements described herein without departing from the spirit and scope of the invention as described in the following claims. In addition, it is to be understood that features described herein independently may, in certain embodiments, be combined.

CLAIMS

1. A system for forming a subsurface wellbore, comprising:

a rack and pinion system comprising a chuck drive system, wherein chuck drive system is configured to operate a drilling string; and

an automatic position control system comprising at least one measurement sensor coupled to the rack and pinion system, wherein the automatic position control system is configured to control the rack and pinion system to determine a position of the drilling string.

2. The system of claim 1, wherein the chuck drive system is configured to hold a tubular.

3. The system of claim 1, wherein the chuck drive system is configured to hold a tubular, and the tubular comprises one or more heaters.

4. The system of claim 1, wherein the chuck drive system is configured to hold a tubular comprising one or more heaters, and at least one of the heaters comprises one or more magnetic ranging sensors and/or one or more non-rotating sensors.

5. The system of claim 1, wherein the automatic position control system is configured to be continuously or semi-continuously calibrated during drilling.

6. The system of claim 1, wherein the automatic position control system comprises one or more rotary steerable system, one or more dual motor rotary steerable systems, or one or more hole measurement systems.

7. The system of claim 1, wherein the auto-position control system comprises one or more hole measurement systems and wherein at least one hole measurement system comprises one or more canted accelerometers.

8. A method for forming a subsurface wellbore, comprising:

receiving position data about a tubular from at least one measurement sensor coupled to an automatic position control system; and

controlling a direction of the tubular in a formation using a rack and pinion system based on the position data from the measurement sensor.

9. The method of claim 8, wherein the measurement sensor comprises one or more canted accelerometers.

10. The method of claim 8, wherein the position data is obtainable in the presence of magnetic interference sources.

11. The method of claim 8, wherein the position data comprises relative rotational data of the tubular shaft.

12. A system for forming a subsurface wellbore, comprising:

a bottom drive system configured to couple to an existing tubular of a drilling string at least partially in the subsurface wellbore and to control a drilling operation in the wellbore, the bottom drive system comprising a circulating sleeve configured to accept a new tubular during the drilling operation; and

a top drive system configured to couple with the new tubular and to assume control of the drilling operation when the new tubular is coupled to the existing tubular.

13. The system of claim 12, wherein the bottom drive system is configured to move at least partially up to the top of the new tubular while the top drive system is controlling the drilling operation and to assume control of the drilling operation from the top drive system.

14. The system of claim 12, further comprising a tubular handling system configured to position the new tubular for coupling with the top drive system.

15. The system of claim 12, wherein the top drive system comprises a circulating sleeve, and the circulating sleeve of the bottom drive system is configured to receive fluid from the circulating sleeve of the top drive system.

16. The system of claim 12, wherein the circulating sleeve is configured to maintain a pressure up to pressures of 13.8 MPa.

17. A method for adding a new tubular to a drilling string, comprising:

coupling a top end of the new tubular to a top drive system;

positioning a bottom end of the new tubular in an opening of a circulating sleeve of a bottom drive system while the bottom drive system controls a drilling operation;

while the drilling operation continues, coupling the new tubular to an existing tubular to form a coupled tubular;

transferring control of the drilling operation from the bottom drive system to the top drive system;

while the drilling operation continues, moving the bottom drive system up the coupled tubular towards the top drive system;

while the drilling operation continues, coupling the bottom drive system to a top portion of the coupled tubular;

transferring control of the drilling operation from the top drive system to the bottom drive system; and disconnecting the top drive system from the coupled tubular.

18. The method of claim 17, further comprising providing fluid to the bottom drive system from the circulating sleeve of the bottom drive system; and, once the new tubular is positioned in the opening of the circulation sleeve of a bottom drive system, providing fluid from a circulating sleeve of the top drive system to the bottom drive system.

19. The method of claim 17, further comprising maintaining a pressure up to 13.8 MPa in the circulating sleeve of the bottom drive system.

20. The method of claim 17, wherein coupling the new tubular to the existing tubular comprises applying sufficient pressure to pressure-fit the tubulars together.

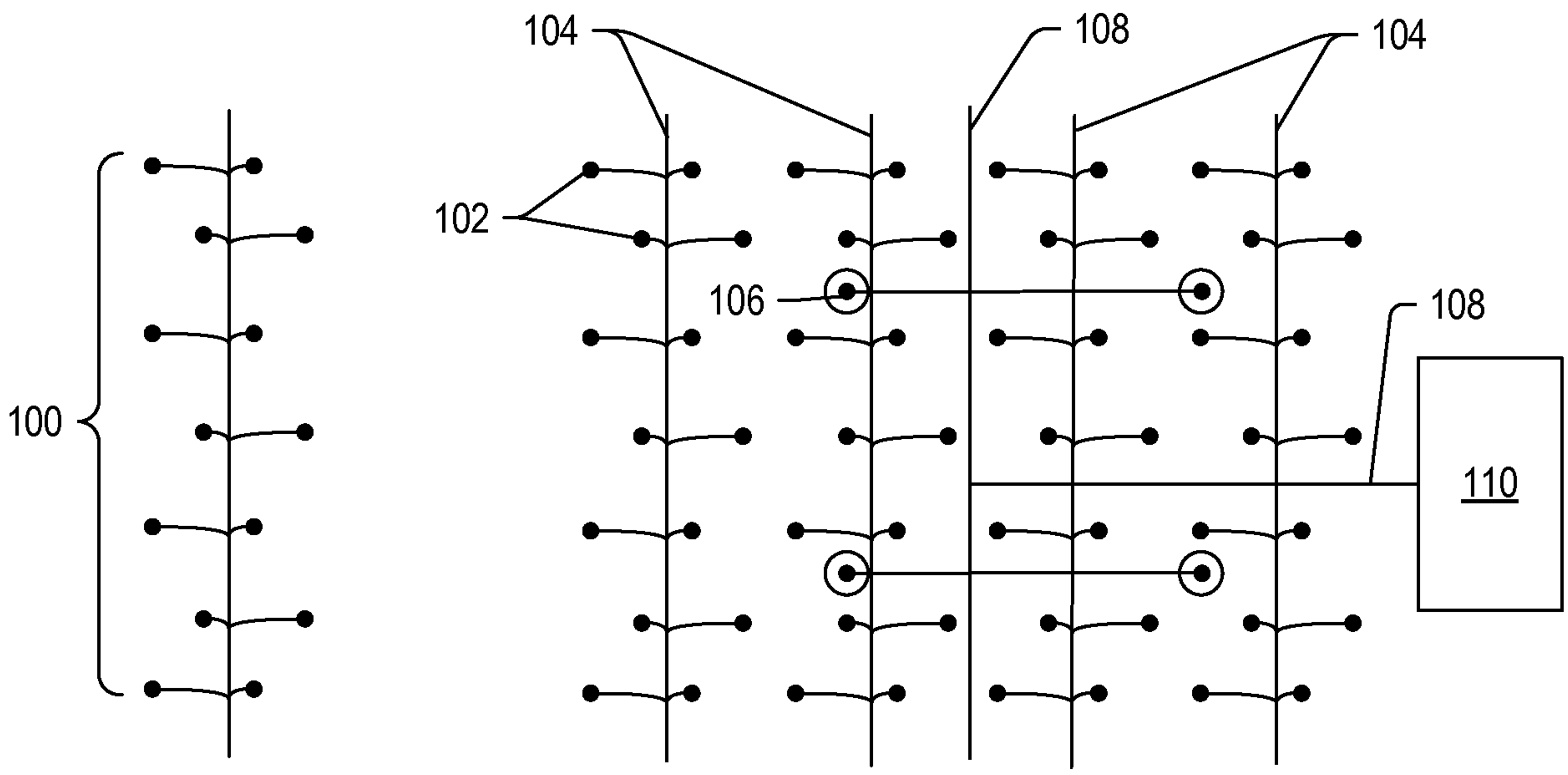

FIG. 1

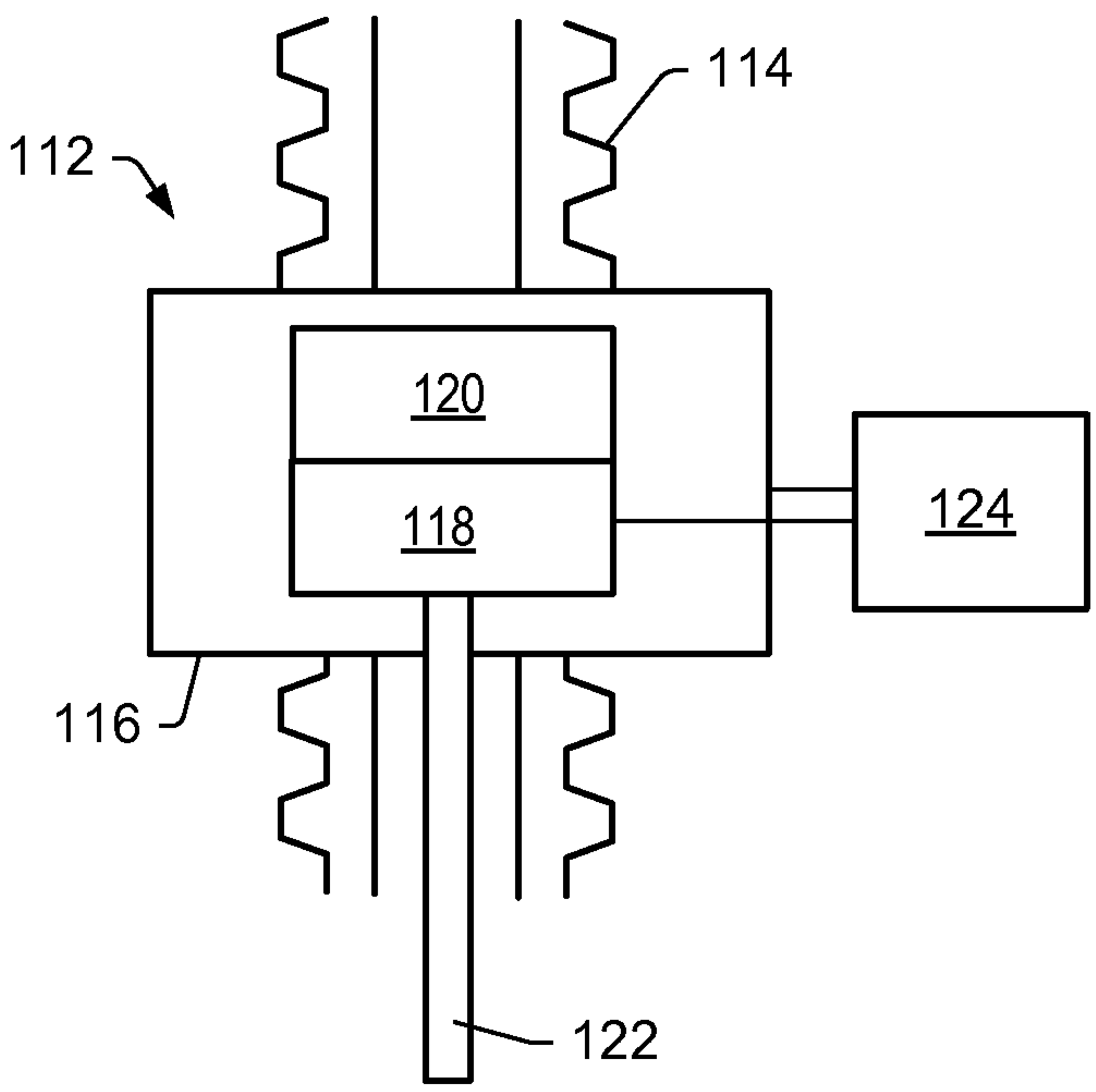

FIG. 2

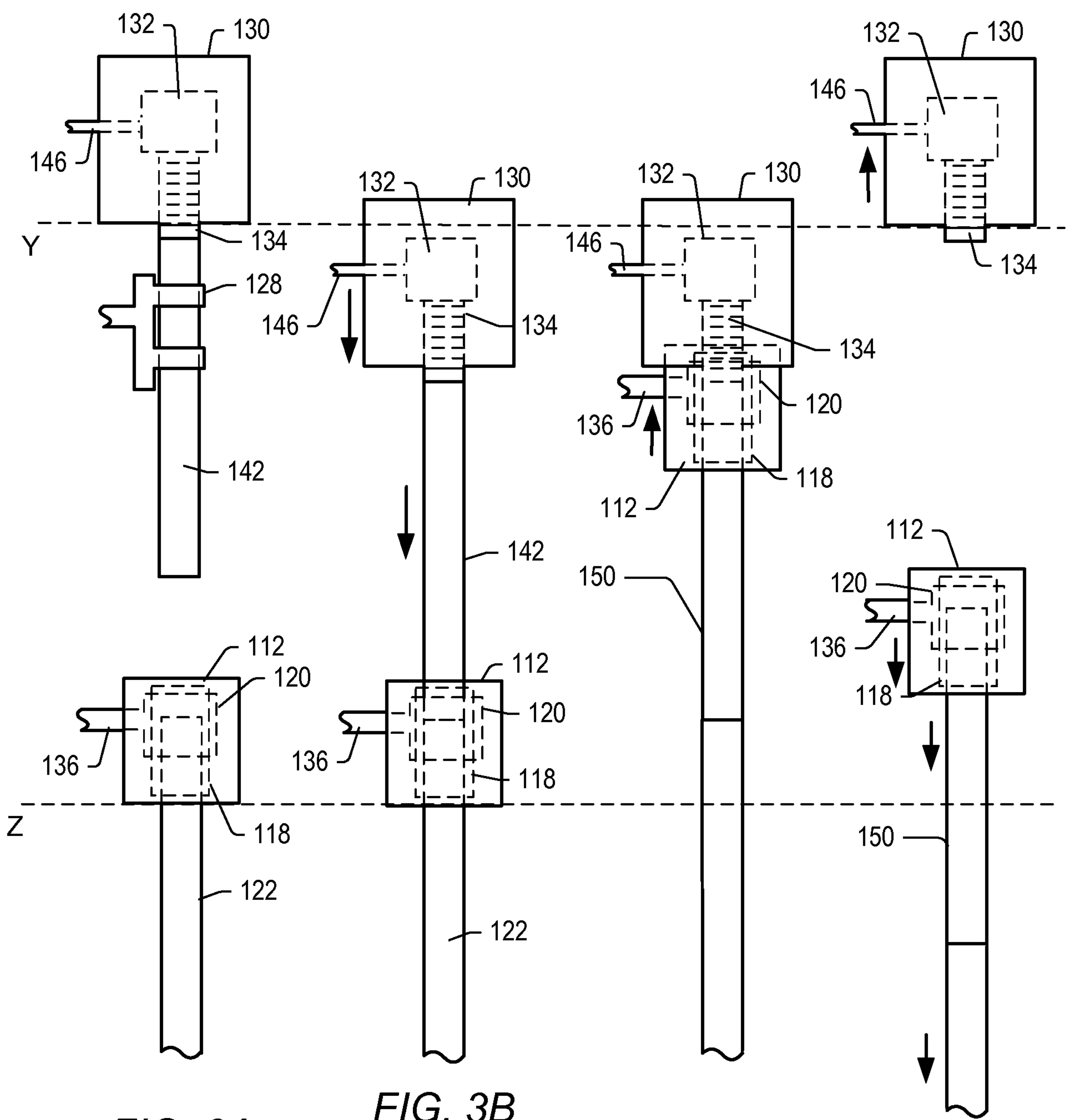

FIG. 3A FIG. 3B FIG. 3C FIG. 3D

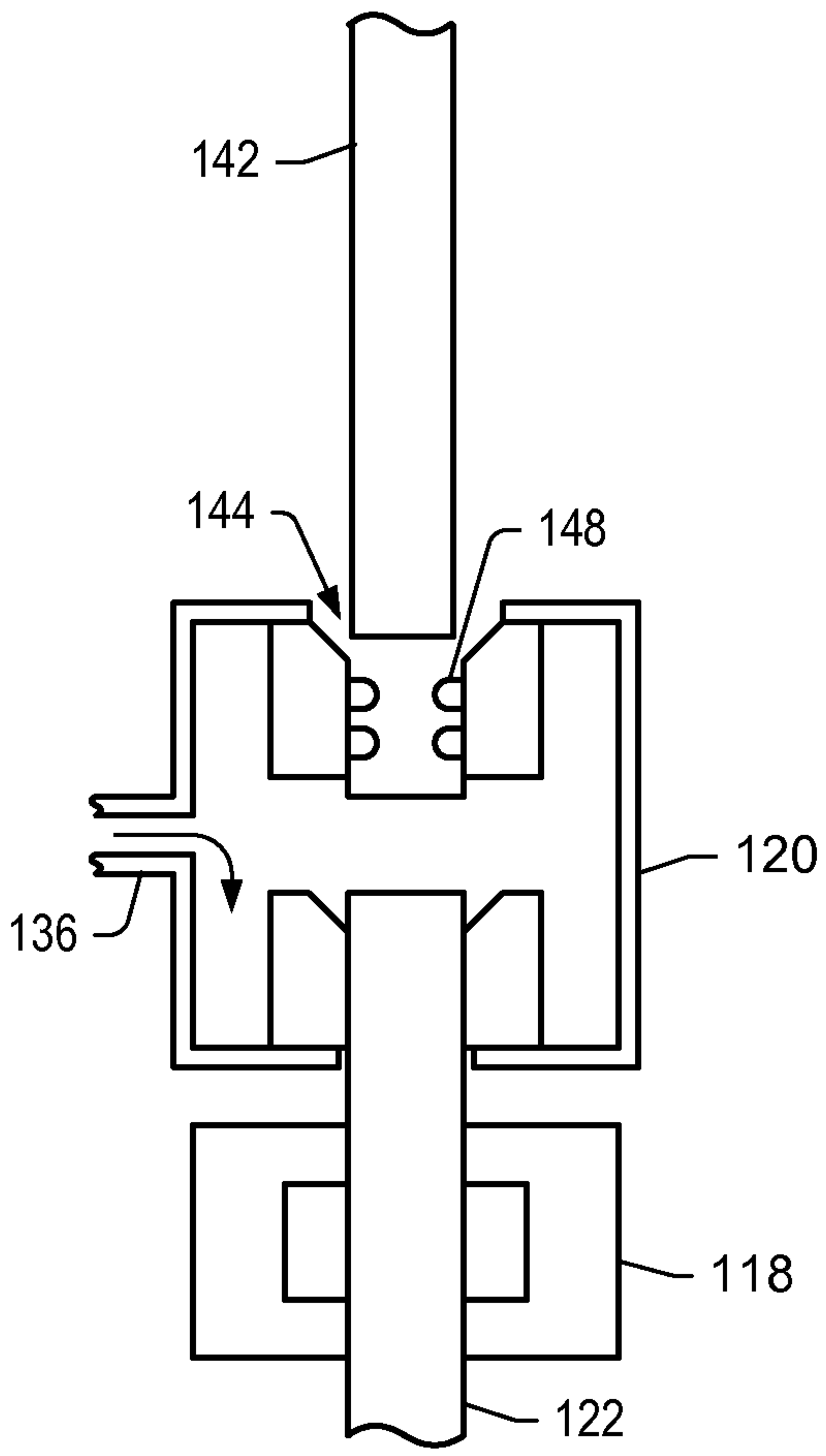

FIG. 4

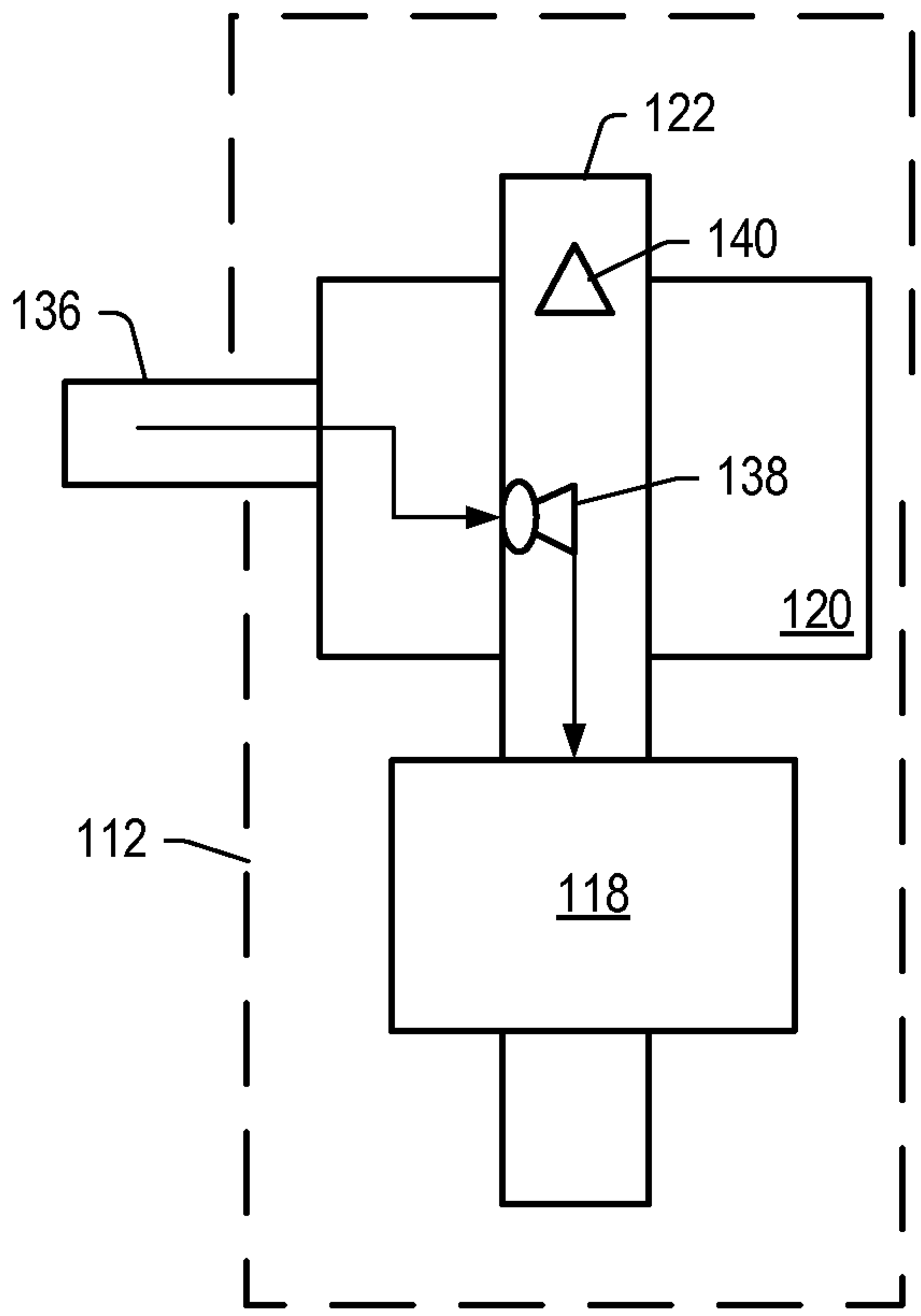

FIG. 5

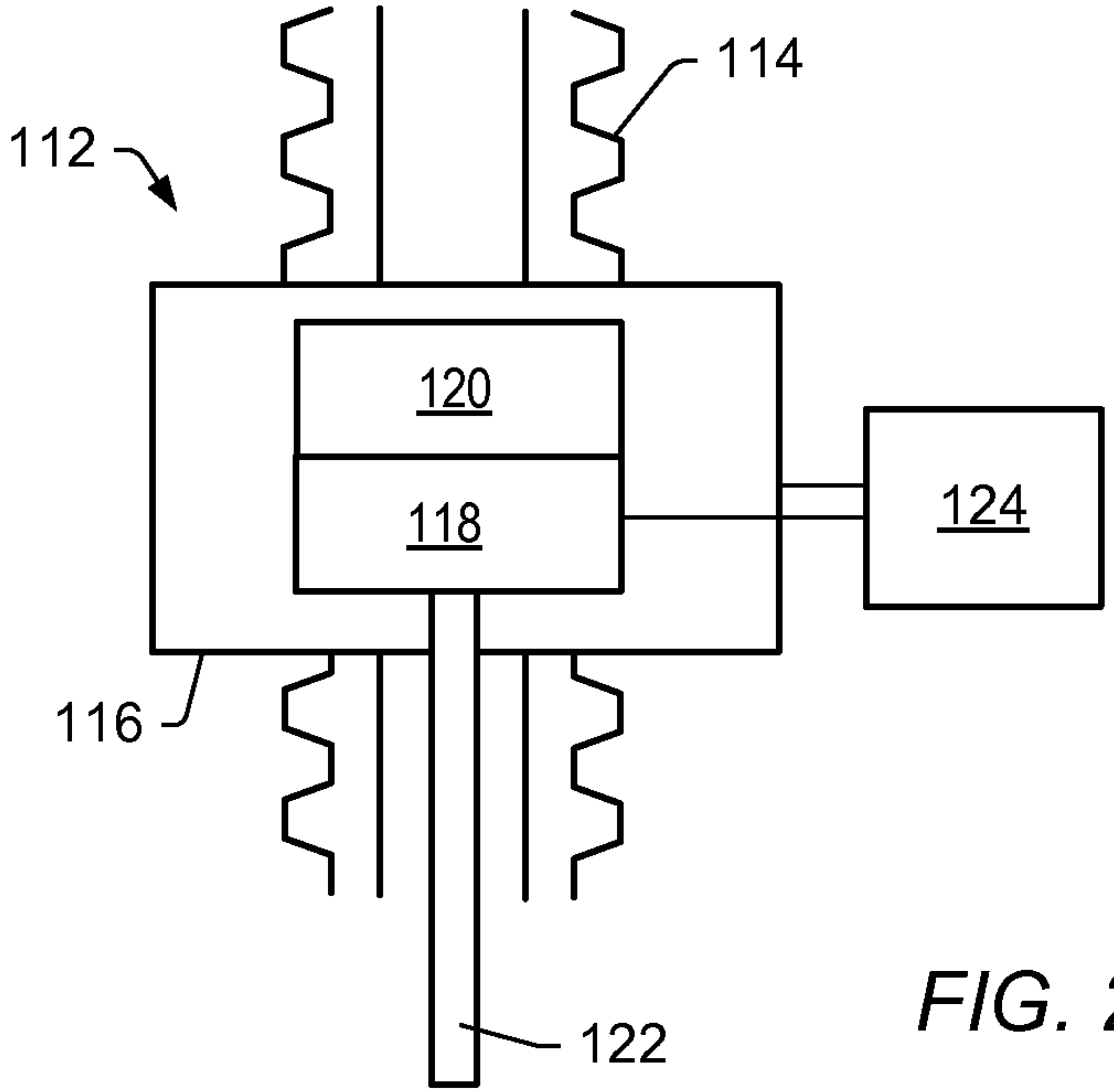

FIG. 2