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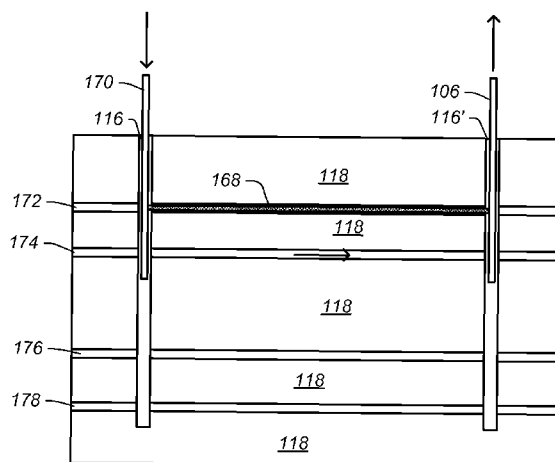


FIG. 11B

(57) Abstract: Systems and methods for heaters used in treating a subsurface formation are described herein. Some embodiments also generally relate to heaters that have novel components therein. Such heaters may be obtained by using the systems and methods described. Some embodiments also generally relate to systems, methods, and/or processes for treating fluid produced from the subsurface formation.

METHODS OF HEATING A SUBSURFACE FORMATION USING ELECTRICALLY CONDUCTIVE PARTICLES

BACKGROUND

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1. Field of the Invention

[0001] The present invention relates generally to systems, methods and heat sources for production of hydrocarbons, hydrogen, and/or other products. The present invention relates in particular to systems and methods using heat sources for treating various subsurface
10 hydrocarbon formations.

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
15 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
20 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
25 characteristics similar to liquid flow.

[0003] Subsurface formations (for example, tar sands or heavy hydrocarbon formations) include dielectric media. Dielectric media may exhibit conductivity, relative dielectric constant, and loss tangents at temperatures below 100 °C. Loss of conductivity, relative dielectric constant, and dissipation factor may occur as the formation is heated to
30 temperatures above 100 °C due to the loss of moisture contained in the interstitial spaces in the rock matrix of the formation. To prevent loss of moisture, formations may be heated at temperatures and pressures that minimize vaporization of water. Conductive solutions may be added to the formation to help maintain the electrical properties of the formation.

[0004] Formations may be heated using electrodes to temperatures and pressures that vaporize the water and/or conductive solutions. Material used to produce the current flow, however, may become damaged due to heat stress and/or loss of conductive solutions may limit heat transfer in the layer. In addition, when using electrodes, magnetic fields may form. Due to the presence of magnetic fields, non-ferromagnetic materials may be desired for overburden casings.

[0005] U.S. Patent No. 4,084,637 to Todd describes methods of producing viscous materials from subterranean formations that includes passing electrical current through the subterranean formation. As the electrical current passes through the subterranean formation, the viscous material is heated to thereby lower the viscosity of such material. Following the heating of the subterranean formation in the vicinity of the path formed by the electrode wells, a driving fluid is injected through the injection wells to thereby migrate along the path and force the material having a reduced viscosity toward the production well. The material is produced through the production well and by continuing to inject a heated fluid through the injection wells, substantially all of the viscous material in the subterranean formation can be heated to lower its viscosity and be produced from the production well.

[0006] U.S. Patent No. 4,926,941 to Glandt et al. describes producing thick tar sand deposits by preheating of thin, relatively conductive layers which are a small fraction of the total thickness of a tar sand deposit. The thin conductive layers serve to confine the heating within the tar sands to a thin zone adjacent to the conductive layers even for large distances between rows of electrodes. The preheating is continued until the viscosity of the tar in a thin preheated zone adjacent to the conductive layers is reduced sufficiently to allow steam injection into the tar sand deposit. The entire deposit is then produced by steam flooding.

[0007] U.S. Patent No. 5,046,559 to Glandt describes an apparatus and method for producing thick tar sand deposits by electrically preheating paths of increased injectivity between an injector and producers. The injector and producers are arranged in a triangular pattern with the injector located at the apex and the producers located on the base of the triangle. These paths of increased injectivity are then steam flooded to produce the hydrocarbons.

[0008] As discussed above, there has been a significant amount of effort to develop methods and systems to economically produce hydrocarbons, hydrogen, and/or other

products from hydrocarbon containing formations. At present, however, there are still many hydrocarbon containing formations from which hydrocarbons, hydrogen, and/or other products cannot be economically produced. Thus, there is a need for improved methods and systems for heating of a hydrocarbon formation and production of fluids from the hydrocarbon formation. There is also a need for improved methods and systems that reduce energy costs for treating the formation, reduce emissions from the treatment process, facilitate heating system installation, and/or reduce heat loss to the overburden as compared to hydrocarbon recovery processes that utilize surface based equipment.

SUMMARY

[0009] Embodiments described herein generally relate to systems, methods, and heaters for treating a subsurface formation. Embodiments described herein also generally relate to heaters that have novel components therein. Such heaters can be obtained by using the systems and methods described herein.

[0010] In certain embodiments, the invention provides one or more systems, methods, and/or heaters. In some embodiments, the systems, methods, and/or heaters are used for treating a subsurface formation.

[0011] In certain embodiments, a system for treating a subsurface formation includes: a first wellbore at least partially located in a hydrocarbon containing formation, wherein the first wellbore comprises a substantially horizontal or inclined portion in a hydrocarbon containing layer in the formation; a first conductor at least partially positioned in the substantially horizontal or inclined portion of the first wellbore, wherein the first conductor comprises electrically conductive material; at least one conductive material substantially surrounding the first conductor in the substantially horizontal or inclined portion of the first wellbore; a second conductor located in the hydrocarbon containing layer in the formation, wherein the second conductor comprises a substantially horizontal or inclined portion in the hydrocarbon containing layer in the formation; at least one conductive material substantially surrounding the substantially horizontal or inclined portion of the second conductor; and a power supply coupled to the first conductor, the power supply configured to electrically excite the electrically conductive materials of the first conductor such that current flows between the electrically conductive materials in the first conductor, through

at least a portion of the formation, to the second conductor, and the current resistively heats at least a portion of the formation between the two conductors.

[0012] In certain embodiments, a system for treating a subsurface formation includes: a first wellbore at least partially located in a hydrocarbon containing formation, wherein the first wellbore comprises a substantially horizontal or inclined portion in a hydrocarbon containing layer in the formation; a first conductor at least partially positioned in the substantially horizontal or inclined portion of the first wellbore, wherein the first conductor comprises electrically conductive material, and wherein at least a portion of the first conductor positioned in the substantially horizontal or inclined portion of the first wellbore comprises copper coupled to the electrically conductive material, the copper tapering from a larger thickness at a first end of the portion to a smaller thickness at a second end of the portion, the first end being closer to an overburden section of the first wellbore than the second end; a power supply coupled to the first conductor, the power supply configured to electrically excite the electrically conductive materials of the first conductor such that current flows between the electrically conductive materials in the first conductor, through at least a portion of the formation, to a second conductor located in the hydrocarbon containing layer in the formation, and the current resistively heats at least a portion of the formation between the two conductors.

[0013] In certain embodiments, a method for heating a hydrocarbon containing formation includes: providing time-varying electrical current at a first frequency to an elongated electrical conductor located in the formation; inducing electrical current flow in a ferromagnetic conductor with the time-varying electrical current at the first frequency, wherein the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor; resistively heating the ferromagnetic conductor with the induced electrical current flow such that the ferromagnetic conductor resistively heats up to a first temperature, wherein the first temperature is at most about 300 °C; allowing heat to transfer from the ferromagnetic conductor at the first temperature to at least a part of the formation; vaporizing at least some water in the formation with the ferromagnetic conductor at the first temperature; providing time-varying electrical current at a second frequency to the elongated electrical conductor; inducing electrical current flow in the ferromagnetic conductor with the time-varying electrical current at the second frequency; resistively heating the ferromagnetic conductor with the induced electrical

current flow such that the ferromagnetic conductor resistively heats up to a second temperature, wherein the second temperature is above about 300 °C; allowing heat to transfer from the ferromagnetic conductor at the second temperature to at least a part of the formation; and mobilizing at least some hydrocarbons in the part of the formation with the ferromagnetic conductor at the second temperature.

[0014] 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.

[0015] In further embodiments, treating a subsurface formation is performed using any of the methods, systems, power supplies, or heaters described herein.

[0016] In further embodiments, additional features may be added to the specific embodiments described herein.

BRIEF DESCRIPTION OF THE DRAWINGS

[0017] Features and advantages of the methods and apparatus of the present invention will be more fully appreciated by reference to the following detailed description of presently preferred but nonetheless illustrative embodiments in accordance with the present invention when taken in conjunction with the accompanying drawings.

[0018] 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.

[0019] FIG. 2 depicts a schematic of an embodiment for treating a subsurface formation using heat sources having electrically conductive material.

[0020] FIG. 3 depicts a schematic of an embodiment for treating a subsurface formation using a ground and heat sources having electrically conductive material.

[0021] FIG. 4 depicts a schematic of an embodiment for treating a subsurface formation using heat sources having electrically conductive material and an electrical insulator.

[0022] FIG. 5 depicts a schematic of an embodiment for treating a subsurface formation using electrically conductive heat sources extending from a common wellbore.

[0023] FIG. 6 depicts a schematic of an embodiment for treating a subsurface formation having a shale layer using heat sources having electrically conductive material.

[0024] FIG. 7 depicts an embodiment of a conduit with heating zone cladding and a conductor with overburden cladding.

[0025] FIG. 8 depicts an embodiment of a u-shaped heater that has an inductively energized tubular.

[0026] FIG. 9 depicts an embodiment of an electrical conductor centralized inside a tubular.

5 [0027] FIG. 10 depicts an embodiment of an induction heater with a sheath of an insulated conductor in electrical contact with a tubular.

[0028] FIGS. 11A through 11D depict a perspective view of embodiments of heating a formation using electrically conductive particles.

10 [0029] FIG. 12 depicts a schematic representation of embodiments of heating a formation using electrically conductive particles in a vertical fracture.

[0030] FIG. 13 depicts a schematic representation of embodiments of heating a formation using electrically conductive particles using a network of fractures.

[0031] FIG. 14 depicts the oil saturation profile of the formation prior to heating.

15 [0032] FIG. 15 depicts a temperature profile in the formation after heating using conductive particles in horizontal fractures at an average temperature rate of 750 °C per day.

[0033] FIG. 16 depicts an oil saturation profile after heating for 810 days using conductive particles.

20 [0034] FIG. 17 depicts a temperature profile in the formation after heating using conductive particles in vertical fracture at an average temperature rate of 600 °C per day.

[0035] FIG. 18 depicts an oil saturation profile after heating for 810 days using conductive particles in vertical fractures.

25 [0036] While the invention is susceptible to various modifications and alternative forms, specific embodiments thereof are shown by way of example in the drawings and will herein be described in detail. The drawings may not be to scale. It should be understood that the drawings and detailed description thereto are not intended to limit the invention to the particular form disclosed, but to 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.

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DETAILED DESCRIPTION

[0037] The following description generally relates to systems and methods for treating hydrocarbons in the formations. Such formations may be treated to yield hydrocarbon products, hydrogen, and other products.

- 5 [0038] “Alternating current (AC)” refers to a time-varying current that reverses direction substantially sinusoidally. AC produces skin effect electricity flow in a ferromagnetic conductor.

- [0039] In the context of reduced heat output heating systems, apparatus, and methods, the term “automatically” means such systems, apparatus, and methods function in a certain
10 way without the use of external control (for example, external controllers such as a controller with a temperature sensor and a feedback loop, PID controller, or predictive controller).

- [0040] “Coupled” means either a direct connection or an indirect connection (e.g., one or more intervening connections) between one or more objects or components. The phrase
15 “directly connected” means a direct connection between objects or components such that the objects or components are connected directly to each other so that the objects or components operate in a “point of use” manner.

- [0041] “Curie temperature” is the temperature above which a ferromagnetic material loses all of its ferromagnetic properties. In addition to losing all of its ferromagnetic properties
20 above the Curie temperature, the ferromagnetic material begins to lose its ferromagnetic properties when an increasing electrical current is passed through the ferromagnetic material.

- [0042] A “formation” includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. “Hydrocarbon layers”
25 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
30 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.

5 [0043] “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
10 removed from the formation.

[0044] “Heat flux” is a flow of energy per unit of area per unit of time (for example, Watts/meter²).

[0045] 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
15 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
20 generated in one or more heat sources is 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
25 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
30 conducting material and/or a heater that provides heat to a zone proximate and/or surrounding a heating location such as a heater well.

[0046] 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.

5 [0047] “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.

10 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.

15 [0048] 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.

[0049] An “in situ heat treatment process” refers to a process of heating a hydrocarbon
20 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.

[0050] “Insulated conductor” refers to any elongated material that is able to conduct
25 electricity and that is covered, in whole or in part, by an electrically insulating material.

[0051] “Modulated direct current (DC)” refers to any substantially non-sinusoidal time-varying current that produces skin effect electricity flow in a ferromagnetic conductor.

[0052] “Nitride” refers to a compound of nitrogen and one or more other elements of the Periodic Table. Nitrides include, but are not limited to, silicon nitride, boron nitride, or
30 alumina nitride.

[0053] “Perforations” include openings, slits, apertures, or holes in a wall of a conduit, tubular, pipe or other flow pathway that allow flow into or out of the conduit, tubular, pipe or other flow pathway.

[0054] “Phase transformation temperature” of a ferromagnetic material refers to a temperature or a temperature range during which the material undergoes a phase change (for example, from ferrite to austenite) that decreases the magnetic permeability of the ferromagnetic material. The reduction in magnetic permeability is similar to reduction in magnetic permeability due to the magnetic transition of the ferromagnetic material at the Curie temperature.

[0055] “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.

[0056] “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.

[0057] “Superposition of heat” refers to providing heat from two or more heat sources to a selected section of a formation such that the temperature of the formation at least at one location between the heat sources is influenced by the heat sources.

[0058] 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.

[0059] “Temperature limited heater” generally refers to a heater that regulates heat output (for example, reduces heat output) above a specified temperature without the use of external controls such as temperature controllers, power regulators, rectifiers, or other

devices. Temperature limited heaters may be AC (alternating current) or modulated (for example, “chopped”) DC (direct current) powered electrical resistance heaters.

[0060] “Thermally conductive fluid” includes fluid that has a higher thermal conductivity than air at standard temperature and pressure (STP) (0 °C and 101.325 kPa).

- 5 [0061] “Thermal conductivity” is a property of a material that describes the rate at which heat flows, in steady state, between two surfaces of the material for a given temperature difference between the two surfaces.

[0062] “Thickness” of a layer refers to the thickness of a cross section of the layer, wherein the cross section is normal to a face of the layer.

- 10 [0063] “Time-varying current” refers to electrical current that produces skin effect electricity flow in a ferromagnetic conductor and has a magnitude that varies with time. Time-varying current includes both alternating current (AC) and modulated direct current (DC).

- [0064] “Turndown ratio” for the temperature limited heater in which current is applied
15 directly to the heater is the ratio of the highest AC or modulated DC resistance below the Curie temperature to the lowest resistance above the Curie temperature for a given current. Turndown ratio for an inductive heater is the ratio of the highest heat output below the Curie temperature to the lowest heat output above the Curie temperature for a given current applied to the heater.

- 20 [0065] 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”.
25

- [0066] 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
30 “wellbore.”

[0067] 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 is maintained below about 120 °C.

[0068] 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 is raised from ambient temperature to temperatures below about 220 °C during removal of water and volatile hydrocarbons.

[0069] 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).

[0070] 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 is 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).

[0071] 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.

[0072] 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.

- 5 [0073] 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.

- [0074] Mobilization and/or pyrolysis products may be produced from the formation
10 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 is raised to
15 pyrolysis temperatures without significant production before reaching pyrolysis temperatures. Formation fluids including pyrolysis products may be produced through the production wells.

- [0075] In some embodiments, the average temperature of one or more sections is raised to temperatures sufficient to allow synthesis gas production after mobilization and/or
20 pyrolysis. In some embodiments, hydrocarbons is 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,
25 steam and/or water) may be introduced into the sections to generate synthesis gas. Synthesis gas may be produced from production wells.

- [0076] 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
30 processes is 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.

[0077] 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

5 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
10 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.

[0078] Heat sources 102 are placed in at least a portion of the formation. Heat sources 102

15 may include 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
20 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 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 is provided by a nuclear power plant or nuclear power plants. The use of nuclear power may
25 allow for reduction or elimination of carbon dioxide emissions from the in situ heat treatment process.

[0079] 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
30 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.

[0080] 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.

[0081] 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.

[0082] 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 remains 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.

[0083] 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)

- 5 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 (C6 hydrocarbons and above) in the production well, and/or (5) increase formation permeability at or proximate the production well.

[0084] Subsurface pressure in the formation may correspond to the fluid pressure generated
10 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
15 production wells, near or at heat sources, or at monitor wells.

[0085] 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
20 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
25 production equipment.

[0086] 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,
30 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.

[0087] In some embodiments, pressure generated by expansion of mobilized fluids, pyrolysis fluids or other fluids generated in the formation may be allowed to increase

5 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
10 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.

[0088] After mobilization and/or pyrolysis temperatures are reached and production from
15 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
20 may contain a larger percentage of olefins.

[0089] 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
25 eliminate the need to compress formation fluids at the surface to transport the fluids in collection conduits to treatment facilities.

[0090] 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
30 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.

[0091] 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 (H₂) 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, H₂ may also neutralize radicals in the generated pyrolyzation fluids. H₂ in the liquid phase may inhibit the generated pyrolyzation fluids from reacting with each other and/or with other compounds in the formation.

[0092] 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. In some embodiments, the transportation fuel is jet fuel, such as JP-8.

[0093] Subsurface formations (for example, tar sands or heavy hydrocarbon formations) include dielectric media. Dielectric media may exhibit conductivity, relative dielectric constant, and loss tangents at temperatures below 100 °C. Loss of conductivity, relative

dielectric constant, and dissipation factor may occur as the formation is heated to temperatures above 100 °C due to the loss of moisture contained in the interstitial spaces in the rock matrix of the formation. To prevent loss of moisture, formations may be heated at temperatures and pressures that minimize vaporization of water. Conductive solutions may
5 be added to the formation to help maintain the electrical properties of the formation.

[0094] Formations may be heated using electrodes to temperatures and pressures that vaporize the water and/or conductive solutions. Material used to produce the current flow, however, may become damaged due to heat stress and/or loss of conductive solutions may limit heat transfer in the layer. In addition, when using electrodes, magnetic fields may
10 form. Due to the presence of magnetic fields, non-ferromagnetic materials may be desired for overburden casings.

[0095] Heat sources with electrically conducting material may allow current flow through a formation from one heat source to another heat source. Current flow between the heat sources with electrically conducting material may heat the formation to increase
15 permeability in the formation and/or lower viscosity of hydrocarbons in the formation. Heating using current flow or “joule heating” through the formation may heat portions of the hydrocarbon layer in a shorter amount of time relative to heating the hydrocarbon layer using conductive heating between heaters spaced apart in the formation.

[0096] In some embodiments, heat sources that include electrically conductive materials
20 are positioned in a hydrocarbon layer. Portions of the hydrocarbon layer may be heated from current generated from the heat sources that flows from the heat sources and through the layer. Positioning of electrically conductive heat sources in a hydrocarbon layer at depths sufficient to minimize loss of conductive solutions may allow hydrocarbons layers to be heated at relatively high temperatures over a period of time with minimal loss of
25 water and/or conductive solutions.

[0097] FIGS. 2-6 depict schematics of embodiments for treating a subsurface formation using heat sources having electrically conductive material. FIG. 2 depicts first conduit 112 and second conduit 114 positioned in wellbores 116, 116' in hydrocarbon layer 118. In certain embodiments, first conduit 112 and/or second conduit 114 are conductors (for
30 example, exposed metal or bare metal conductors). In some embodiments, conduits 112, 114 are oriented substantially horizontally or at an incline in the formation. Conduits 112, 114 may be positioned in or near a bottom portion of hydrocarbon layer 118.

[0098] Wellbores 116, 116' may be open wellbores. In some embodiments, the conduits extend from a portion of the wellbore. In some embodiments, the vertical or overburden portions of wellbores 116, 116' are cemented with non-conductive cement or foam cement. Wellbores 116, 116' may include packers 120 and/or electrical insulators 122. In some
5 embodiments, packers 120 are not necessary. Electrical insulators 122 may insulate conduits 112, 114 from casing 124.

[0099] In some embodiments, the portion of casing 124 adjacent to overburden 126 is made of material that inhibits ferromagnetic effects. The casing in the overburden may be made of fiberglass, polymers, and/or a non-ferromagnetic metal (for example, a high
10 manganese steel). Inhibiting ferromagnetic effects in the portion of casing 124 adjacent to overburden 126 may reduce heat losses to the overburden and/or electrical losses in the overburden. In some embodiments, overburden casings 124 include non-metallic materials such as fiberglass, polyvinylchloride (PVC), chlorinated polyvinylchloride (CPVC), high-density polyethylene (HDPE), and/or non-ferromagnetic metals (for example, non-
15 ferromagnetic high manganese steels). HDPEs with working temperatures in a range for use in overburden 126 include HDPEs available from Dow Chemical Co., Inc. (Midland, Michigan, U.S.A.). In some embodiments, casing 124 includes carbon steel coupled on the inside and/or outside diameter of a non-ferromagnetic metal (for example, carbon steel clad with copper or aluminum) to inhibit ferromagnetic effects or inductive effects in the carbon
20 steel. Other non-ferromagnetic metals include, but are not limited to, manganese steels with at least 15% by weight manganese, 0.7% by weight carbon, 2% by weight chromium, iron aluminum alloys with at least 18% by weight aluminum, and austenitic stainless steels such as 304 stainless steel or 316 stainless steel.

[0100] Portions or all of conduits 112, 114 may include electrically conductive material
25 128. Electrically conductive materials include, but are not limited to, thick walled copper, heat treated copper ("hardened copper"), carbon steel clad with copper, aluminum, or aluminum or copper clad with stainless steel. Conduits 112, 114 may have dimensions and characteristics that enable the conduits to be used later as injection wells and/or production wells. Conduit 112 and/or conduit 114 may include perforations or openings 130 to allow
30 fluid to flow into or out of the conduits. In some embodiments, portions of conduit 112 and/or conduit 114 are pre-perforated with coverings initially placed over the perforations

and removed later. In some embodiments, conduit 112 and/or conduit 114 include slotted liners.

[0101] After a desired time (for example, after injectivity has been established in the layer), the coverings of the perforations may be removed or slots may be opened to open portions of conduit 112 and/or conduit 114 to convert the conduits to production wells and/or injection wells. In some embodiments, coverings are removed by inserting an expandable mandrel in the conduits to remove coverings and/or open slots. In some embodiments, heat is used to degrade material placed in the openings in conduit 112 and/or conduit 114. After degradation, fluid may flow into or out of conduit 112 and/or conduit 114.

[0102] Power to electrically conductive material 128 may be supplied from one or more surface power supplies through conductors 132, 132'. Conductors 132, 132' may be cables supported on a tubular or other support member. In some embodiments, conductors 132, 132' are conduits through which electricity flows to conduit 112 or conduit 114. Electrical connectors 134 may be used to electrically couple conductors 132, 132' to conduits 112, 114. Conductor 132 and conductor 132' may be coupled to the same power supply to form an electrical circuit. Sections of casing 124 (for example a section between packers 120 and electrical connectors 134) may include or be made of insulating material (such as enamel coating) to prevent leakage of electrical current towards the surface of the formation.

[0103] In some embodiments, a direct current power source is supplied to either first conduit 112 or second conduit 114. In some embodiments, time varying current is supplied to first conduit 112 and/or second conduit 114. Current flowing from conductors 132, 132' to conduits 112, 114 may be low frequency current (for example, about 50 Hz, about 60 Hz, or frequencies up to about 1000 Hz). A voltage differential between the first conduit 112 and second conduit 114 may range from about 100 volts to about 1200 volts, from about 200 volts to about 1000 volts, or from about 500 volts to 700 volts. In some embodiments, higher frequency current and/or higher voltage differentials is utilized. Use of time varying current may allow longer conduits to be positioned in the formation. Use of longer conduits allows more of the formation to be heated at one time and may decrease overall operating expenses. Current flowing to first conduit 112 may flow through hydrocarbon layer 118 to second conduit 114, and back to the power supply. Flow of

current through hydrocarbon layer 118 may cause resistance heating of the hydrocarbon layer.

[0104] During the heating process, current flow in conduits 112, 114 may be measured at the surface. Measuring of the current entering conduits 112, 114 may be used to monitor

the progress of the heating process. Current between conduits 112, 114 may increase steadily until a predetermined upper limit (I_{max}) is reached. In some embodiments,

vaporization of water occurs at the conduits, at which time a drop in current is observed.

Current flow of the system is indicated by arrows 136. Current flow in hydrocarbon

containing layer 118 between conduits 112, 114 heats the hydrocarbon layer between and

around the conduits. Conduits 112, 114 may be part of a pattern of conduits in the

formation that provide multiple pathways between wells so that a large portion of layer 118

is heated. The pattern may be a regular pattern, (for example, a triangular or rectangular pattern) or an irregular pattern.

[0105] FIG. 3 depicts a schematic of an embodiment of a system for treating a subsurface

formation using electrically conductive material. Conduit 138 and ground 140 may extend from wellbores 116, 116' into hydrocarbon layer 118. Ground 140 may be a rod or a

conduit positioned in hydrocarbon layer 118 between about 5 m and about 30 m away from conduit 138 (for example, about 10 m, about 15 m, or about 20 m). In some embodiments,

electrical insulators 122' electrically isolate ground 140 from casing 124' and/or conduit

section- 142 positioned in wellbore 116'. As shown, ground 140 is a conduit that includes openings 130.

[0106] Conduit 138 may include sections 144, 146 of conductive material 128. Sections

144, 146 may be separated by electrically insulating material 148. Electrically insulating

material 148 may include polymers and/or one or more ceramic isolators. Section 144 may

be electrically coupled to the power supply by conductor 132. Section 146 may be

electrically coupled to the power supply by conductor 132'. Electrical insulators 122 may

separate conductor 132 from conductor 132'. Electrically insulating material 148 may have dimensions and insulating properties sufficient to inhibit current from section 144 flowing

across insulation material 148 to section 146. For example, a length of electrically

insulating material 148 may be about 30 meters, about 35 meters, about 40 meters, or

greater. Using a conduit that has electrically conductive sections 144, 146 may allow fewer

wellbores to be drilled in the formation. Conduits having electrically conductive sections

(“segmented heat sources”) may allow longer conduit lengths. In some embodiments, segmented heat sources allow injection wells used for drive processes (for example, steam assisted gravity drainage and/or cyclic steam drive processes) to be spaced further apart, and thus achieve an overall higher recovery efficiency.

5 [0107] Current provided through conductor 132 may flow to conductive section 144 through hydrocarbon layer 118 to a section of ground 140 opposite section 144. The electrical current may flow along ground 140 to a section of the ground opposite section 146. The current may flow through hydrocarbon layer 118 to section 146 and through conductor 132' back to the power circuit to complete the electrical circuit. Electrical
10 connector 150 may electrically couple section 146 to conductor 132'. Current flow is indicated by arrows 136. Current flow through hydrocarbon layer 118 may heat the hydrocarbon layer to create fluid injectivity in the layer, mobilize hydrocarbons in the layer, and/or pyrolyze hydrocarbons in the layer. When using segmented heat sources, the amount of current required for the initial heating of the hydrocarbon layer may be at least
15 50% less than current required for heating using two non-segmented heat sources or two electrodes. Hydrocarbons may be produced from hydrocarbon layer 118 and/or other sections of the formation using production wells. In some embodiments, one or more portions of conduit 138 is positioned in a shale layer and ground 140 is positioned in hydrocarbon layer 118. Current flow through conductors 132, 132' in opposite directions
20 may allow for cancellation of at least a portion of the magnetic fields due to the current flow. Cancellation of at least a portion of the magnetic fields may inhibit induction effects in the overburden portion of conduit 138 and the wellhead of wellbore 116.

[0108] FIG. 4 depicts an embodiment in which first conduit 138 and second conduit 138' are used for heating hydrocarbon layer 118. Electrically insulating material 148 may
25 separate sections 144, 146 of first conduit 138. Electrically insulating material 148' may separate sections 144', 146' of second conduit 138'.

[0109] Current may flow from a power source through conductor 132 of first conduit 138 to section 144. The current may flow through hydrocarbon containing layer 118 to section 146' of second conduit 138'. The current may return to the power source through
30 conductor 132' of second conduit 138'. Similarly, current may flow through conductor 132 of second conduit 138' to section 144', through hydrocarbon layer 118 to section 146 of first conduit 138, and the current may return to the power source through conductor 132' of

the first conduit 138. Current flow is indicated by arrows 136. Generation of current flow from electrically conductive sections of conduits 138, 138' may heat portions of hydrocarbon layer 118 between the conduits and create fluid injectivity in the layer, mobilize hydrocarbons in the layer, and/or pyrolyze hydrocarbons in the layer. In some embodiments, one or more portions of conduits 138, 138' are positioned in shale layers.

[0110] By creating opposite current flow through the wellbores, as described with reference to FIGS. 3 and 4, magnetic fields in the overburden may cancel out. Cancellation of the magnetic fields in the overburden may allow ferromagnetic materials to be used in overburden casings 124. Using ferromagnetic casings in the wellbores may be less expensive and/or easier to install than non-ferromagnetic casings (such as fiberglass casings).

[0111] In some embodiments, two or more conduits branch from a common wellbore. FIG. 5 depicts a schematic of an embodiment of two conduits extending from one common wellbore. Extending the conduits from one common wellbore may reduce costs by forming fewer wellbores in the formation. Using common wellbores may allow wellbores to be spaced further apart and produce the same heating efficiencies and the same heating times as drilling two different wellbores for each conduit through the formation. Using common wellbores may allow ferromagnetic materials to be used in overburden casing 124 since the magnetic fields cancel due to the approximately equal and opposite flow of current in the overburden section of conduits 112, 114. Extending conduits from one common wellbore may allow longer conduits to be used.

[0112] Conduits 112, 114 may extend from common vertical portion 152 of wellbore 116. Conduit 114 may be installed through an opening (for example, a milled window) in vertical portion 152. Conduits 112, 114 may extend substantially horizontally or inclined from vertical portion 152. Conduits 112, 114 may include electrically conductive material 128. In some embodiments, conduits 112, 114 include electrically conductive sections and electrically insulating material, as described for conduit 138 in FIGS. 3 and 4. Conduit 112 and/or conduit 114 may include openings 130. Current may flow from a power source to conduit 112 through conductor 132. The current may pass through hydrocarbon containing layer 118 to conduit 114. The current may pass from conduit 114 through conductor 132' back to the power source to complete the circuit. The flow of current as shown by arrows

136 through hydrocarbon layer 118 from conduits 112, 114 heats the hydrocarbon layer between the conduits.

[0113] In certain embodiments, electrodes (such as conduits 112, 114, conduit 138, and/or ground 140) are coated or clad with high electrical conductivity material to reduce energy losses. In some embodiments, overburden conductors (such as conductor 132) are coated or clad with high electrical conductivity material. FIG. 7 depicts an embodiment of conduit 112 with heating zone cladding 154 and conductor 132 with overburden cladding 156. In certain embodiments, conduit 112 is made of carbon steel. Cladding 154 may be copper or another highly electrically conductive material. In certain embodiments, cladding 154 and/or cladding 156 is coupled to conduit 112 and/or conductor 132 by wrapping thin layers of the cladding onto the conduit or conductor. In some embodiments, cladding 154 and/or cladding 156 is coupled to conduit 112 and/or conductor 132 by depositing or coating the cladding using electrolysis.

[0114] In certain embodiments, overburden cladding 156 has a substantially constant thickness along the length of conductor 132 as the current along the conductor is substantially constant. In the hydrocarbon layer of the formation, however, electrical current flows into the formation and electrical current decreases linearly along the length of conduit 112 if current injection into the formation is uniform. Since current in conduit 112 decreases along the length of the conduit, heating zone cladding 154 can decrease in thickness linearly along with the current while still reducing energy losses to acceptable levels along the length of the conduit. Having heating zone cladding 154 taper to a thinner thickness along the length of conduit 112 reduces the total cost of putting the cladding on the conduit.

[0115] The taper of heating zone cladding 154 may be selected to provide certain electrical output characteristics along the length of conduit 112. In certain embodiments, the taper of heating zone cladding 154 is designed to provide an approximately constant current density along the length of the conduit such that the current decreases linearly along the length of the conduit. In some embodiments, the thickness and taper of heating zone cladding 154 is designed such that the formation is heated at or below a selected heating rate (for example, at or below about 160 W/m). In some embodiments, the thickness and taper of heating zone cladding 154 is designed such that a voltage gradient along the cladding is less than a selected value (for example, less than about 0.3 V/m).

[0116] In certain embodiments, analytical calculations may be made to optimize the thickness and taper of heating zone cladding 154. The thickness and taper of heating zone cladding 154 may be optimized to produce substantial cost savings over using a heating zone cladding of constant thickness. For example, it may be possible to reduce costs by more than 50% by tapering heating zone cladding 154 along the length of conduit 112.

[0117] In certain embodiments, boreholes of electrodes (such as conduits 112, 114, conduit 138, and/or ground 140) are filled with an electrically conductive material and/or a thermally conductive material. For example, the insides of conduits may be filled with the electrically conductive material and/or the thermally conductive material. In certain embodiments, the wellbores with electrodes are filled with graphite, conductive cement, or combinations thereof. Filling the wellbore with electrically and/or thermally conductive material may increase the effective electrical diameter of the electrode for conducting current into the formation and/or increase distribution of any heat generated in the wellbore.

[0118] FIG. 8 depicts an embodiment of a u-shaped heater that has an inductively energized tubular. Heater 158 includes electrical conductor 160 and tubular 162 in an opening that spans between wellbore 116A and wellbore 116B. In certain embodiments, electrical conductor 160 and/or the current carrying portion of the electrical conductor is electrically insulated from tubular 162. Electrical conductor 160 and/or the current carrying portion of the electrical conductor is electrically insulated from tubular 162 such that electrical current does not flow from the electrical conductor to the tubular, or vice versa (for example, the tubular is not electrically connected to the electrical conductor).

[0119] In some embodiments, electrical conductor 160 is centralized inside tubular 162 (for example, using centralizers 164 or other support structures, as shown in FIG. 9).

Centralizers 164 may electrically insulate electrical conductor 160 from tubular 162. In some embodiments, tubular 162 contacts electrical conductor 160. For example, tubular 162 may hang, drape, or otherwise touch electrical conductor 160. In some embodiments, electrical conductor 160 includes electrical insulation (for example, magnesium oxide or porcelain enamel) that insulates the current carrying portion of the electrical conductor from tubular 162. The electrical insulation inhibits current from flowing between the current carrying portion of electrical conductor 160 and tubular 162 if the electrical conductor and the tubular are in physical contact with each other.

[0120] In some embodiments, electrical conductor 160 is an exposed metal conductor heater or a conductor-in-conduit heater. In certain embodiments, electrical conductor 160 is an insulated conductor such as a mineral insulated conductor. The insulated conductor may have a copper core, copper alloy core, or a similar electrically conductive, low resistance core that has low electrical losses. In some embodiments, the core is a copper core with a diameter between about 0.5" (1.27 cm) and about 1" (2.54 cm). The sheath or jacket of the insulated conductor may be a non-ferromagnetic, corrosion resistant steel such as 347 stainless steel, 625 stainless steel, 825 stainless steel, 304 stainless steel, or copper with a protective layer (for example, a protective cladding). The sheath may have an outer diameter of between about 1" (2.54 cm) and about 1.25" (3.18 cm).

[0121] In some embodiments, the sheath or jacket of the insulated conductor is in physical contact with the tubular 162 (for example, the tubular is in physical contact with the sheath along the length of the tubular) or the sheath is electrically connected to the tubular. In such embodiments, the electrical insulation of the insulated conductor electrically insulates the core of the insulated conductor from the jacket and the tubular. FIG. 10 depicts an embodiment of an induction heater with the sheath of an insulated conductor in electrical contact with tubular 162. Electrical conductor 160 is the insulated conductor. The sheath of the insulated conductor is electrically connected to tubular 162 using electrical contactors 166. In some embodiments, electrical contactors 166 are sliding contactors. In certain embodiments, electrical contactors 166 electrically connect the sheath of the insulated conductor to tubular 162 at or near the ends of the tubular. Electrically connecting at or near the ends of tubular 162 substantially equalizes the voltage along the tubular with the voltage along the sheath of the insulated conductor. Equalizing the voltages along tubular 162 and along the sheath may inhibit arcing between the tubular and the sheath.

[0122] Tubular 162, shown in FIGS. 8, 9, and 10, may be ferromagnetic or include ferromagnetic materials. Tubular 162 may have a thickness such that when electrical conductor 160 is energized with time-varying current, the electrical conductor induces electrical current flow on the surfaces of tubular 162 due to the ferromagnetic properties of the tubular (for example, current flow is induced on both the inside of the tubular and the outside of the tubular). Current flow is induced in the skin depth of the surfaces of tubular 162 so that the tubular operates as a skin effect heater. In certain embodiments, the

induced current circulates axially (longitudinally) on the inside and/or outside surfaces of tubular 162. Longitudinal flow of current through electrical conductor 160 induces primarily longitudinal current flow in tubular 162 (the majority of the induced current flow is in the longitudinal direction in the tubular). Having primarily longitudinal induced
5 current flow in tubular 162 may provide a higher resistance per foot than if the induced current flow is primarily angular current flow.

[0123] In certain embodiments, current flow in tubular 162 is induced with low frequency current in electrical conductor 160 (for example, from 50 Hz or 60 Hz up to about 1000 Hz). In some embodiments, induced currents on the inside and outside surfaces of tubular
10 162 are substantially equal.

[0124] In certain embodiments, tubular 162 has a thickness that is greater than the skin depth of the ferromagnetic material in the tubular at or near the Curie temperature of the ferromagnetic material or at or near the phase transformation temperature of the ferromagnetic material. For example, tubular 162 may have a thickness of at least 2.1, at
15 least 2.5 times, at least 3 times, or at least 4 times the skin depth of the ferromagnetic material in the tubular near the Curie temperature or the phase transformation temperature of the ferromagnetic material. In certain embodiments, tubular 162 has a thickness of at least 2.1 times, at least 2.5 times, at least 3 times, or at least 4 times the skin depth of the ferromagnetic material in the tubular at about 50 °C below the Curie temperature or the
20 phase transformation temperature of the ferromagnetic material.

[0125] In certain embodiments, tubular 162 is carbon steel. In some embodiments, tubular 162 is coated with a corrosion resistant coating (for example, porcelain or ceramic coating) and/or an electrically insulating coating. In some embodiments, electrical conductor 160 has an electrically insulating coating. Examples of the electrically insulating coating on
25 tubular 162 and/or electrical conductor 160 include, but are not limited to, a porcelain enamel coating, alumina coating, or alumina-titania coating. In some embodiments, tubular 162 and/or electrical conductor 160 are coated with a coating such as polyethylene or another suitable low friction coefficient coating that may melt or decompose when the heater is energized. The coating may facilitate placement of the tubular and/or the
30 electrical conductor in the formation.

[0126] In some embodiments, tubular 162 includes corrosion resistant ferromagnetic material such as, but not limited to, 410 stainless steel, 446 stainless steel, T/P91 stainless

steel, T/P92 stainless steel, alloy 52, alloy 42, and Invar 36. In some embodiments, tubular 162 is a stainless steel tubular with cobalt added (for example, between about 3% by weight and about 10% by weight cobalt added) and/or molybdenum (for example, about 0.5 % molybdenum by weight).

5 [0127] At or near the Curie temperature or the phase transformation temperature of the ferromagnetic material in tubular 162, the magnetic permeability of the ferromagnetic material decreases rapidly. When the magnetic permeability of tubular 162 decreases at or near the Curie temperature or the phase transformation temperature, there is little or no current flow in the tubular because, at these temperatures, the tubular is essentially non-ferromagnetic and electrical conductor 160 is unable to induce current flow in the tubular. 10 With little or no current flow in tubular 162, the temperature of the tubular will drop to lower temperatures until the magnetic permeability increases and the tubular becomes ferromagnetic. Thus, tubular 162 self-limits at or near the Curie temperature or the phase transformation temperature and operates as a temperature limited heater due to the ferromagnetic properties of the ferromagnetic material in the tubular. Because current is 15 induced in tubular 162, the turndown ratio may be higher and the drop in current sharper for the tubular than for temperature limited heaters that apply current directly to the ferromagnetic material. For example, heaters with current induced in tubular 162 may have turndown ratios of at least about 5, at least about 10, or at least about 20 while temperature 20 limited heaters that apply current directly to the ferromagnetic material may have turndown ratios that are at most about 5.

[0128] When current is induced in tubular 162, the tubular provides heat to hydrocarbon layer 118 and defines the heating zone in the hydrocarbon layer. In certain embodiments, tubular 162 heats to temperatures of at least about 300 °C, at least about 500 °C, or at least 25 about 700 °C. Because current is induced on both the inside and outside surfaces of tubular 162, the heat generation of the tubular is increased as compared to temperature limited heaters that have current directly applied to the ferromagnetic material and current flow is limited to one surface. Thus, less current may be provided to electrical conductor 160 to generate the same heat as heaters that apply current directly to the ferromagnetic material. 30 Using less current in electrical conductor 160 decreases power consumption and reduces power losses in the overburden of the formation.

[0129] In certain embodiments, tubulars 162 have large diameters. The large diameters may be used to equalize or substantially equalize high pressures on the tubular from either the inside or the outside of the tubular. In some embodiments, tubular 162 has a diameter in a range between about 1.5" (about 3.8 cm) and about 5" (about 12.7 cm). In some
5 embodiments, tubular 162 has a diameter in a range between about 3 cm and about 13 cm, between about 4 cm and about 12 cm, or between about 5 cm and about 11 cm. Increasing the diameter of tubular 162 may provide more heat output to the formation by increasing the heat transfer surface area of the tubular.

[0130] In some embodiments, fluids flow through the annulus of tubular 162 or through
10 another conduit inside the tubular. The fluids may be used, for example, to cool down the heater, to recover heat from the heater, and/or to initially heat the formation before energizing the heater.

[0131] In some embodiments, a method for heating a hydrocarbon containing formation includes providing a time-varying electrical current at a first frequency to an elongated
15 electrical conductor located in the formation using an inductive heater. Electrical current flow may be induced in a ferromagnetic conductor with the time-varying electrical current at the first frequency. In some embodiments, the ferromagnetic conductor at least partially surrounds and at least partially extends lengthwise around the electrical conductor. The ferromagnetic conductor may be resistively heated with the induced electrical current flow.
20 For example, the ferromagnetic conductor may be resistively heated with the induced electrical current flow such that the ferromagnetic conductor resistively heats up to a first temperature. The first temperature may be at most about 300 °C. Heat may be allowed to transfer from the ferromagnetic conductor at the first temperature to at least a part of the formation. At least some water in the formation may be vaporized with the ferromagnetic
25 conductor at the first temperature. At these lower temperatures (for example, up to about 260 °C or about 300 °C) coke may be inhibited from forming without inducing heater damage.

[0132] In some embodiments, the time-varying electrical current is provided at a second frequency to the elongated electrical conductor. Electrical current flow may be induced in
30 the ferromagnetic conductor with the time-varying electrical current at the second frequency. The ferromagnetic conductor may be resistively heated with the induced electrical current flow. For example, the ferromagnetic conductor may be resistively

heated with the induced electrical current flow such that the ferromagnetic conductor resistively heats up to a second temperature. The second temperature may be above about 300 °C. Heat may be allowed to transfer from the ferromagnetic conductor at the second temperature to at least a part of the formation. At least some hydrocarbons in the part of the formation may be mobilized with the ferromagnetic conductor at the second temperature. Caution must be taken with the second frequency, in that it must not be raised to high or the inductive heater may be damaged. Multiple frequency low temperature inductive heaters are manufactured by Siemens AG (Munich, Germany).

[0133] In some embodiments, hydrocarbon formations include pre-existing openings and/or fractures (for example, highly fractured carbonate formations, highly permeable layers (for example, greater than 1 Darcy) which water can be injected, or the like). In some embodiments, the fractures are small. For example the fracture dimension may range from 0.01 mm to 1.0 mm.

[0134] The fractures may form interconnecting pathways (horizontal, vertical and inclined pathways) in the formation. In some embodiments, the fractures are substantially horizontal or inclined in the formation and are separated by hydrocarbon layers. One or more fractures may be substantially vertical in the formation and be separated by hydrocarbon layers. In some embodiments, vertical fractures intersect horizontal fractures. In some embodiments, one or more wellbores are connected to one or more fractures in the formation. The fractures have sufficient size to allow fluid and/or particles to be injected into the fractures without further fracturing. In some embodiments, particle are injected in the formation through an injection well proximate one or more substantially horizontal fractures or include fractures. The particles may be circulated through the horizontal fracture to an injection well until a desired amount of particles fill the fracture. The injection well may include one or more screens (for example, sand screens) to inhibit particles from entering the injection well. The particles may be injected as solids or a solution of particles and liquid (for example, a slurry). The liquid used to inject the particles may include, but is not limited to, a conductive solution, water, hydrocarbons, hydrocarbons produced from the formation, or a mixture thereof.

[0135] The particles may include electrically conductive material (for example, carbon, petroleum coke fines, petroleum coated coke particles, or coke produced during heating of formation). The particle size may range vary. For example, the particles size may range

from about 1 micron to about 50,000 microns. Heating of particles in the fractures may produce a cross-flow of hydrocarbons in the formation (for example, flow of hydrocarbons in a horizontal and vertical direction). In some embodiments, the particles have a narrow range of sizes to allow packing of the fracture with a maximum amount of void space so fluids will flow through the packed fractures. A wide range of particle sizes allows smaller particles will fill the spaces between the larger particles, thus densely packed solids are obtained while allowing fluid to flow from an injection well to a production well.

[0136] A system for treating a subsurface formation may include a plurality of conduits at least partially located in a portion of a hydrocarbon containing formation. At least parts of two of the conduits are aligned in relation to each other such that electrical current will flow from a first conduit to a second conduit. The first and second conduits may include electrically conductive material. Electrically conductive particles may be provided to the formation and be in communication with the first and second conduits. Electrical current may be applied to the particles to heat at least a portion of the formation. A power supply may be coupled to the first and second conduits and electrically excite at least one of the conductive sections and at least a portion of the particles such that current flows between the first conduit the particles and the second conduit in the formation and heats at least a portion of the formation between the two conduits and proximate the particles.

[0137] The particles may be loosely packed when initially injected in the natural fractures of the highly permeable layers. As the formation is heated, coke may form from cracking of hydrocarbons (for example, bitumen), thus forming particles in situ. Formation of particles in situ may increase connectivity of the particles as compared to the connectivity prior to heating the formation. Increasing the connectivity of the particles may enhance the electrical resistivity of the formation. In some embodiments, the use of particles as a conductive medium may allow the formation to self-heal. For example, if there is an electrical flow path with a highly resistant segment, the segment may have a temperature greater than the rest of the flow path. Coke may form in the hot spot, thus decreasing the electrical resistance in the hotter segment. The decrease of electrical resistance may allow the temperature of the segment to cool, thus decreasing the amount of coke being produced in the hot segment.

[0138] In some embodiments, the production well and the injection well are movably positionable in wellbores near one or more substantially horizontal or inclined fractures. In

some embodiments, vertical fractures intersect the substantially horizontal fractures. The ends of the injection well and production well may be sealed to inhibit flow or substantially inhibit flow of particles to other fractures or portions in the formation. Particles may be circulated through the injection well, a first fracture, and the production well. Once the first fracture fills with a desired amount of electrically conductive particles, the injection well and the production well may be positioned past second fracture. Particles may be circulated from the injection well through second fracture to the production well until the desired amount of particles fill the second fracture. In some embodiments, vertical and horizontal fractures are filled. In an embodiment, vertical fractures are filled with particles. The process may continue until the desired number of fractures are filled with particles. The production and injection well may be replaced with electrodes conduits and the system heated resistively.

[0139] FIGS. 11A through 11D depict a schematic representation of embodiments of heating a formation using electrically conductive particles. Particles or a solution of electrically conductive particles 168 are injected through injection well 170 positioned in wellbore 116 of hydrocarbon layer 118. The solution may be a conductive solution, water, or hydrocarbons, hydrocarbons produced from the formation or a mixture thereof. Particles 168 may be circulated through hydrocarbon layer 118 through fractures 172, 174, 176, 178 in the hydrocarbon layer to production well 106 positioned in wellbore 116' of the hydrocarbon layer. A distance between wellbores 116, 116' may be range from 30 m to 500 m, from 50 m to 400 m or from 100 m to 250 m. As shown, fractures 172, 174, 176, 178 are substantially horizontal in hydrocarbon layer 118. In some embodiments, fractures 172, 174, 176, 178 are pre-existing fractures. Production well 106 and injection well 170 may be vertical or substantially vertical to fractures 172, 174, 176, 178. It should be understood that the fractures may be substantially vertical and the injection well and production well may be oriented substantially horizontally to the fractures.

[0140] Production well 106 and injection well 170 are movably positionable in wellbores 116, 116'. As shown in FIG. 11A, ends of injection well 170 and production well 106 are positioned below first fracture 172. The ends may be sealed to inhibit flow or substantially inhibit flow of particles 168 to other fractures or portions in the formation. Particles 168 may be circulated through injection well 170, first fracture 172 and production well 106 using known techniques for circulating fluid in a formation (for example, pressurizing the

particles using a fluid). Once first fracture 172 fills with a desired amount of electrically conductive particles 168, ends of injection well 170 and production well 106 may be positioned past second fracture 174 as shown in FIG. 11B. Particles may be circulated from injection well 170 through second fracture 174 to production well 106 until the
5 desired amount of particles fill the second fracture. The process may continue until the desired number of fractures are filled with particles. As shown in FIG. 11C, third fracture 176 and fourth fracture 178 have been filled with electrically conductive particles 168. In some embodiments, two or more fractures are filled at once with particles. For example, fractures 172, 174, 176, 178 may be filled with electrically conductive particles 168 at the
10 same time and/or the order in which the fractures are filled may vary.

[0141] Once the desired amount of particles are positioned in the fractures in the hydrocarbon layer, injection well 170 and production well 106 may be replaced with first conduit 180 and second conduit 182 as shown in FIG. 11D. First conduit 180 and second conduit 182 may include electrically conductive material (for example, electrodes or
15 electrically conducting conduits described herein). Conduits 180, 182 may be selectively positioned near the fractures containing the electrically conductive particles 168.

[0142] A direct current power source (not shown) is supplied to either first conduit 180 or second conduit 182. In some embodiments, time varying current is supplied to first conduit 180 and/or second conduit 182. Current flowing to conduits 180, 182 may be low
20 frequency current (for example, about 50 Hz, about 60 Hz, or frequencies up to about 1000 Hz). A voltage differential between the first conduit 180 and second conduit 182 may range from about 100 volts to about 1200 volts, from about 200 volts to about 1000 volts, or from about 500 volts to 700 volts. In some embodiments, higher frequency current and/or higher voltage differentials may be utilized. Use of time varying current may allow
25 longer conduits to be positioned in the formation. Use of longer conduits allows more of the formation to be heated at one time and may decrease overall operating expenses. Current flowing (depicted by arrows 184) to first conduit 180 and electrically conductive particles 168 may flow through hydrocarbon layer 118 to second conduit 182, and back to the power supply. Flow of current through hydrocarbon layer 118 may cause resistance
30 heating of the hydrocarbon layer.

[0143] As shown, in FIG. 11D, conduits 180, 182 are positioned proximate fractures 172, 174, 176, 178. It should be understood that conduits 180, 182 may be selectively

positioned near one or more of the fractures in the formation. For example, conduits 180, 182 may be positioned proximate first fracture 172 that contains electrically conductive particles 168. Current may be applied to the conduits and particles and portions of hydrocarbon layer 118 near first fracture 172 may be heated resistively. After sufficient heating, conduits 180, 182 may be positioned proximate another fracture (for example fracture 176) and the process continued to heat the hydrocarbon layer.

[0144] FIGS. 12 and 13 depict a schematic representation of embodiments of heating a formation using electrically conductive particles. In FIG. 12, conductive particles 168 are positioned in vertical fracture 186. In FIG. 13, conductive particles 168 are positioned in vertical fracture 186 and horizontal fractures 172, 176. Conduits 180, 182 are positioned proximate fractures 172, 174, 176, 178. Current may be applied to the conduits and particles and portions of hydrocarbon layer 118 near first fracture 172 may be heated resistively. After sufficient heating, conduits 180, 182 may be positioned proximate another fracture (for example fracture 176) and the process continued to heat the hydrocarbon layer. Positioning of particles in vertical fractures alone or in combination with horizontal fractures may allow cross-flow of hydrocarbons in hydrocarbon layer 118.

Examples

[0145] Non-limiting examples are set forth.

[0146] *Heating with conductive particles*

[0147] Simulations were used to simulate heating of a formation containing fractures using conductive particles (for example, patterns shown in FIGS. 11-13). The formation was a 2D dual permeability model having small scale fractures and 20 m highly permeable fractures. The conductivity of the reservoir was ignored and a heating rate of the formation was constant.

[0148] FIG. 14 depicts the oil saturation profile of the formation prior to heating. Hydrocarbon containing layers 118 are separated by horizontal fractures 188. Oil saturation is shown on a scale of 0.00 to 1.00 with 1.00 being 100% oil saturation. The oil saturation scale is shown in the sidebar. FIG. 15 depicts a temperature profile in the formation after heating using conductive particles in horizontal fractures 188 at an average temperature rate of 750 °C per day. The hottest spots are at or near fractures 188. The temperature profile shows that portions of the formation near and between the fractures are warmer than other portions of the formation. These warmer portions create more mobility

between the fractures and create a flow path for fluids in the formation. FIG. 16 depicts an oil saturation profile after heating for 810 days using conductive particles. Oil saturation is shown on a scale of 0.00 to 1.00 with 1.00 being 100% oil saturation. The oil saturation scale is shown in the sidebar. The oil saturation profile in FIG. 16 shows mobilization of hydrocarbons through portions of the formation previously separated by fractures.

[0149] FIG. 17 depicts a temperature profile in the formation after heating conductive particles in vertical fracture 190 at an average temperature rate of 600 °C per day.

Hydrocarbon containing layers 118 are separated by vertical fracture 188. FIG. 18 depicts an oil saturation profile after heating for 810 days using conductive particles in vertical fractures. Oil saturation is shown on a scale of 0.00 to 1.00 with 1.00 being 100% oil saturation. The oil saturation scale is shown in the sidebar. The oil saturation profile in FIG. 18 shows mobilization and cross-flow of oil through portions of the formation previously separated by fractures.

[0150] It is to be understood the invention is not limited to particular systems described which may, of course, vary. It is also to be understood that the terminology used herein is for the purpose of describing particular embodiments only, and is not intended to be limiting. As used in this specification, the singular forms “a”, “an” and “the” include plural referents unless the content clearly indicates otherwise. Thus, for example, reference to “a core” includes a combination of two or more cores and reference to “a material” includes mixtures of materials.

[0151] Further modifications and alternative embodiments of various aspects of the invention will 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.

CLAIMS:

1. A system for treating a subsurface formation, comprising:

a plurality of conduits at least partially located in a portion of a hydrocarbon
5 containing formation, wherein at least part of two of the conduits are aligned in relation to
each other such that electrical current will flow from a first conduit to a second conduit, and
wherein the first and second conduits comprise electrically conductive material;

particles located in the portion of the hydrocarbon formation and in communication
with the first and second conduits, wherein the particles comprise electrically conductive
10 material; and

a power supply coupled to the first and second conduits, the power supply configured
to electrically excite at least one of the conductive sections and at least a portion of the
particles such that current flows between the first conduit, the particles, and the second
conduit in the formation and heats at least a portion of the formation between the two
15 conduits and proximate the particles.

2. The system of claim 1, wherein at least a portion of the first conduit and at least a portion
of the second conduit are substantially vertical in the formation.

3. The system of claim 1, wherein at least a portion of the first conduit and at least a portion
of the second conduit are substantially parallel to each other.

4. The system of claim 1, wherein at least a portion of the particles are located in a
substantially horizontal opening in the formation.

5. The system of claim 1, wherein at least a portion of the first conduit and at least a portion
of the second conduit are substantially vertical in the formation and the particles are located
in a substantially horizontal opening in the formation, wherein the substantially horizontal
opening is in communication with the first and second conduit.
25

6. The system of claim 1, wherein at least a portion of the first conduit and at least a portion
of the second conduit are substantially vertical in the formation and the particles are located
in at least one substantially horizontal opening and at least one substantially vertical opening
in the formation, wherein the substantially horizontal opening is in communication with the
first and second conduit and the substantially vertical opening is in communication with the
30 substantially horizontal opening.

7. The system of claim 1, wherein at least a portion of the particles are located in a highly
permeable fracture in the formation.

8. The system of claim 1, wherein at least a portion of the particles are located in an opening in the formation having a permeability of greater than about 1 Darcy.
9. The system of claim 1, wherein at least a portion of the particles are located in a pre-existing opening in the formation.
- 5 10. The system of claim 1, wherein at least a portion of the particles comprise carbon.
11. A method of treating a hydrocarbon formation,
- providing one or more particles to a portion of a hydrocarbon formation, wherein at least a portion of the particles comprise electrically conductive material;
- providing electrical current to at least a portion of the particles to heat at least a part of
- 10 the formation.
12. The method of claim 11, wherein providing the particles comprising injecting a solution of liquid and particles into one or more fractures in the portion of the formation.
13. The method of claim 11, wherein the particles are provided to at least one of fracture, wherein the fracture is substantially vertical relative to other fractures in the formation.
- 15 14. The method of claim 11, wherein the particles are provided to at least one substantially horizontal fracture or inclined fracture and/or at least one substantially vertical relative to other fractures in the formation.
15. The method of claim 11, wherein providing the particles comprising injecting a solution of liquid and particles into one or more fractures in the portion of the formation, wherein at
- 20 least one of the fractures is substantially vertical relative to other fractures in the formation.
16. The method of claim 11, wherein the electrically conductive material of the particles comprises carbon.
17. The method of claim 11, wherein providing the particles comprises:
- positioning an injection well proximate a first end of a substantially horizontal
- 25 fracture;
- positioning a production well proximate a second end of the substantially horizontal fracture; and
- circulating particles from the injection well through the substantially horizontal fracture to the production well.
- 30 18. The method of claim 17, further comprising moving the production well and injection well proximate a second substantially horizontal fracture and providing particles to the second substantially horizontal fracture.

19. The method of claim 17, wherein the production well is configured to inhibit flow of particles to the surface.

20. A method for treating a subsurface formation, comprising:

providing particles to an opening in a portion of the formation, wherein the particles

5 comprise electrically conductive material;

providing a plurality of conduits to a section of the formation, wherein a first conduit and a second conduit of the plurality of conduits are in communication with the electrically conductive particles;

10 providing electrical current to a first conduit in a section of the formation such that electrical current flows from the first conduit to a second conduit in the section of the formation,

allowing sufficient electrical current to flow through at least a portion of the formation such that at least a part of the formation is heated.

21. A method of treating a hydrocarbon formation, comprising providing electrical current to
15 at least a portion of conductive particles in a section of the formation such that at least a portion of the formation is heated.

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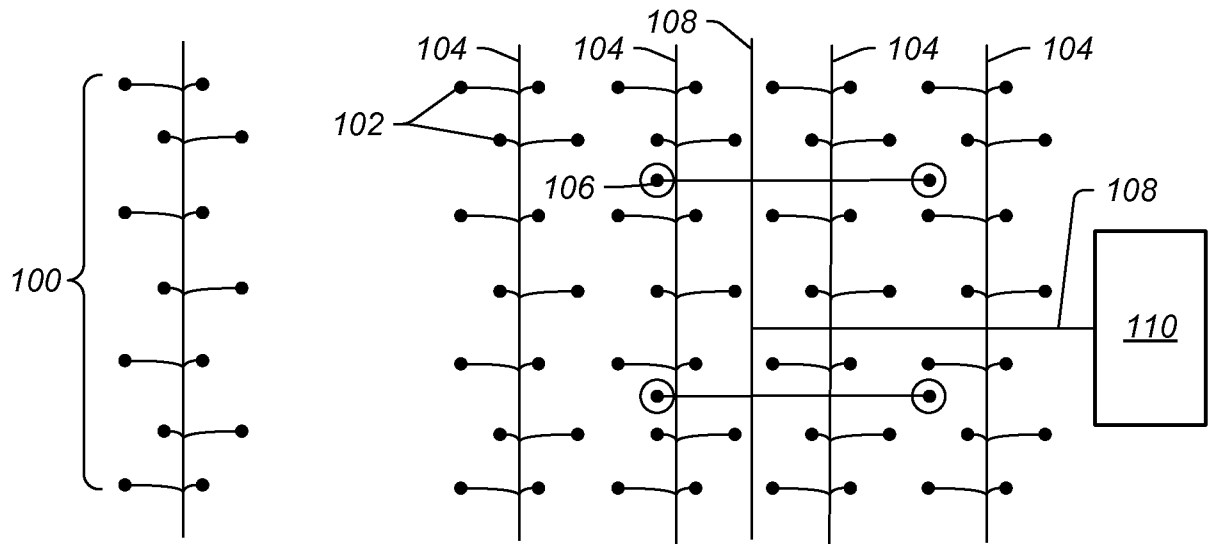


FIG. 1

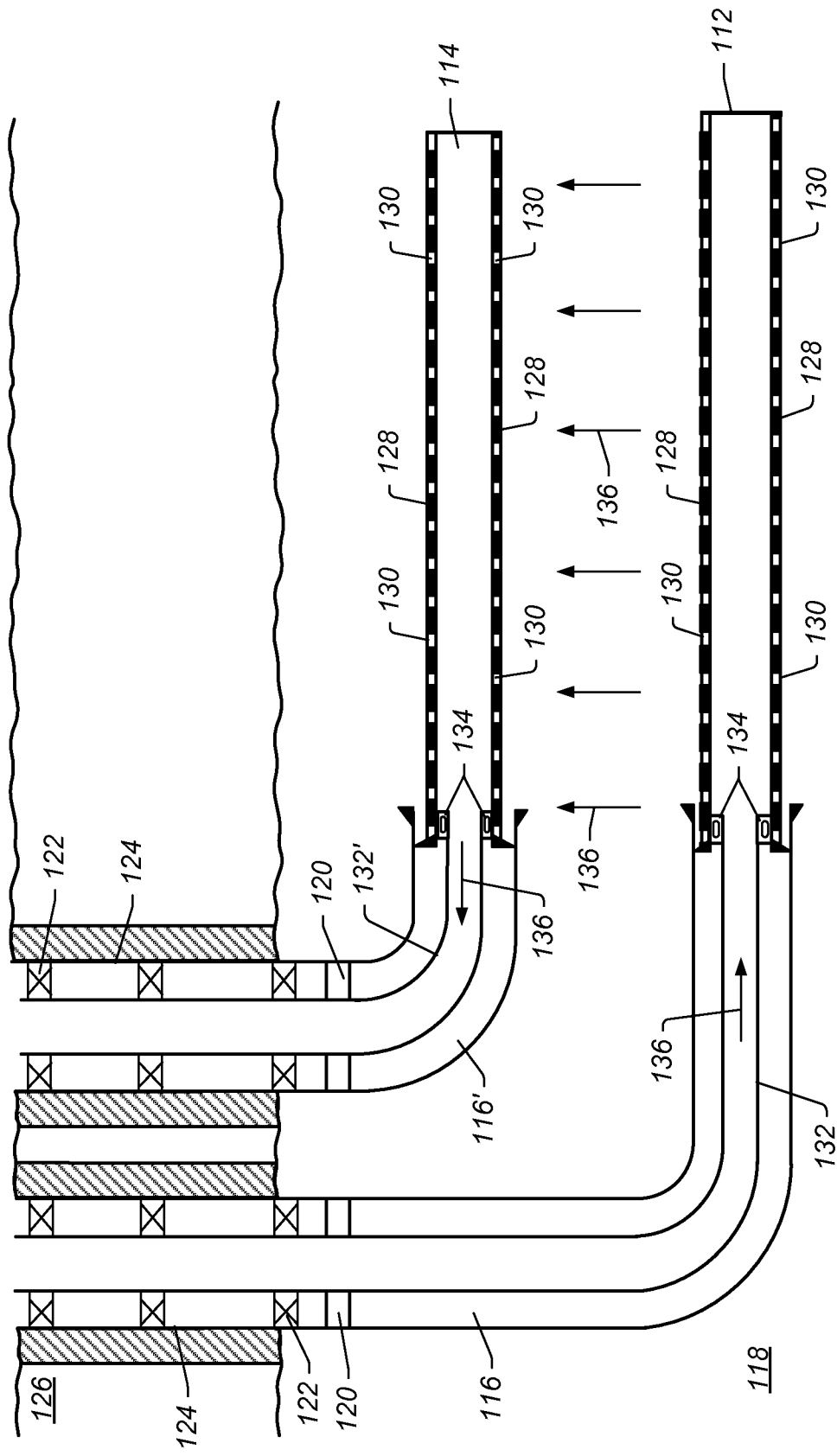


FIG. 2

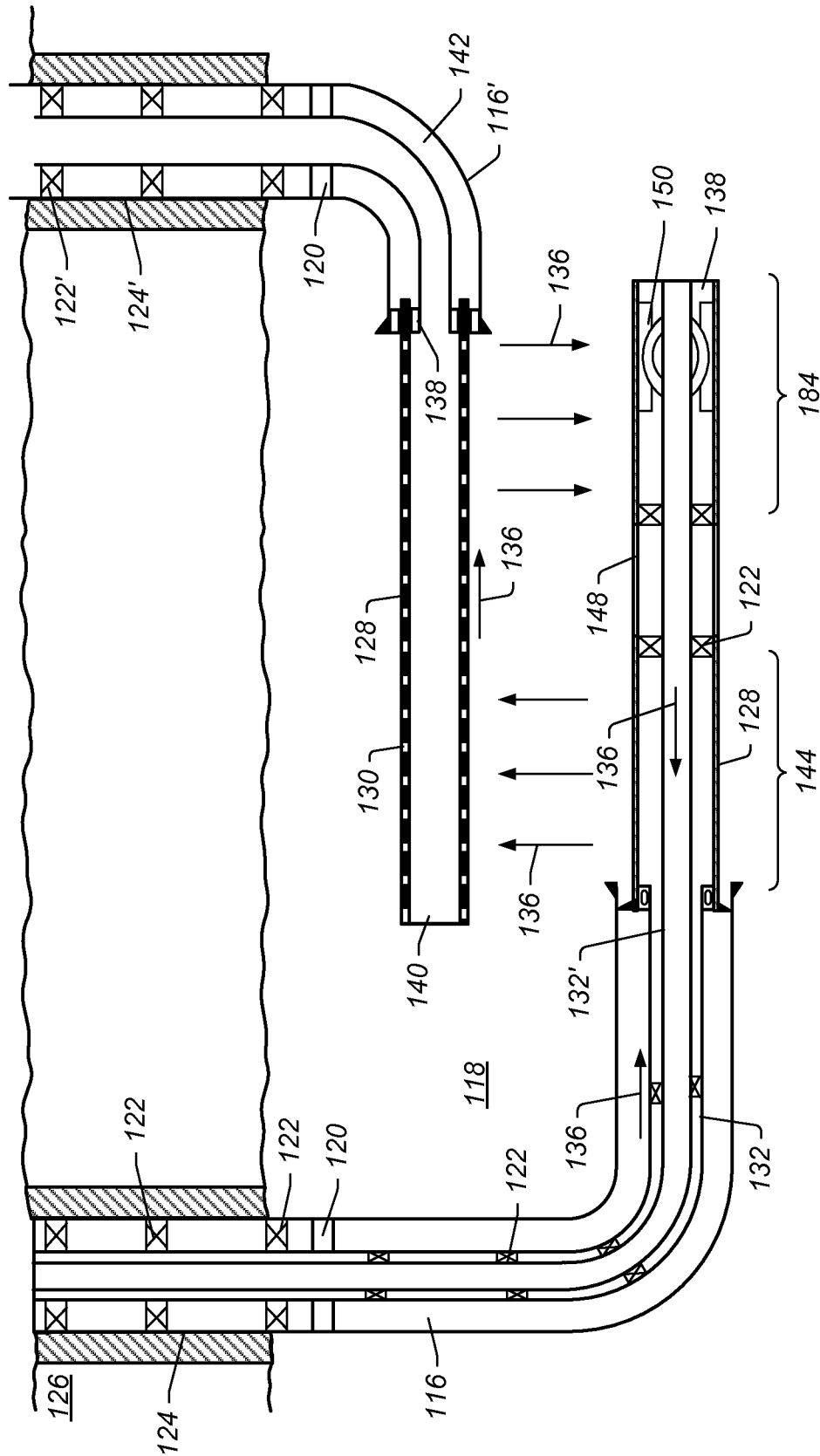


FIG. 3

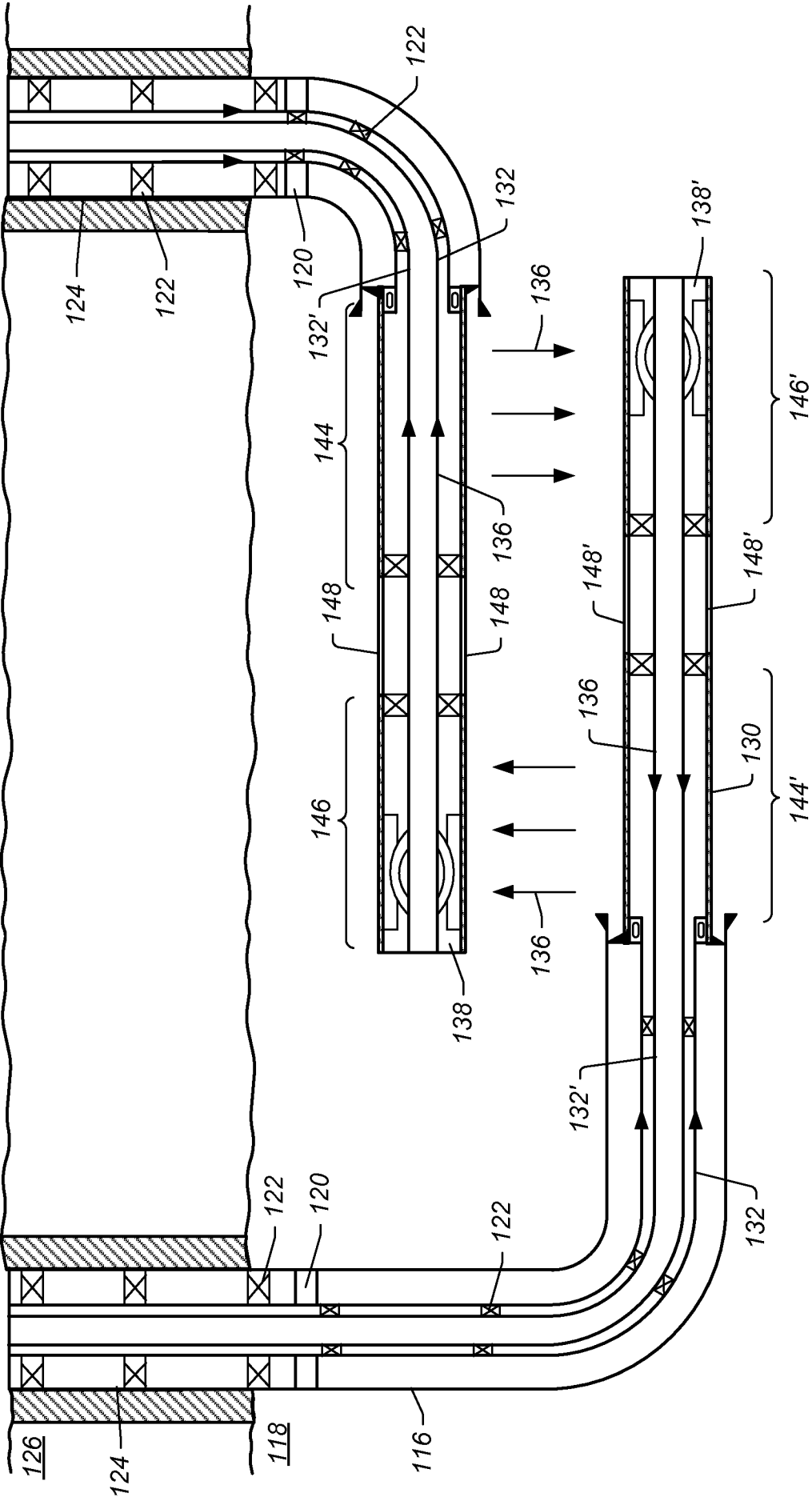


FIG. 4

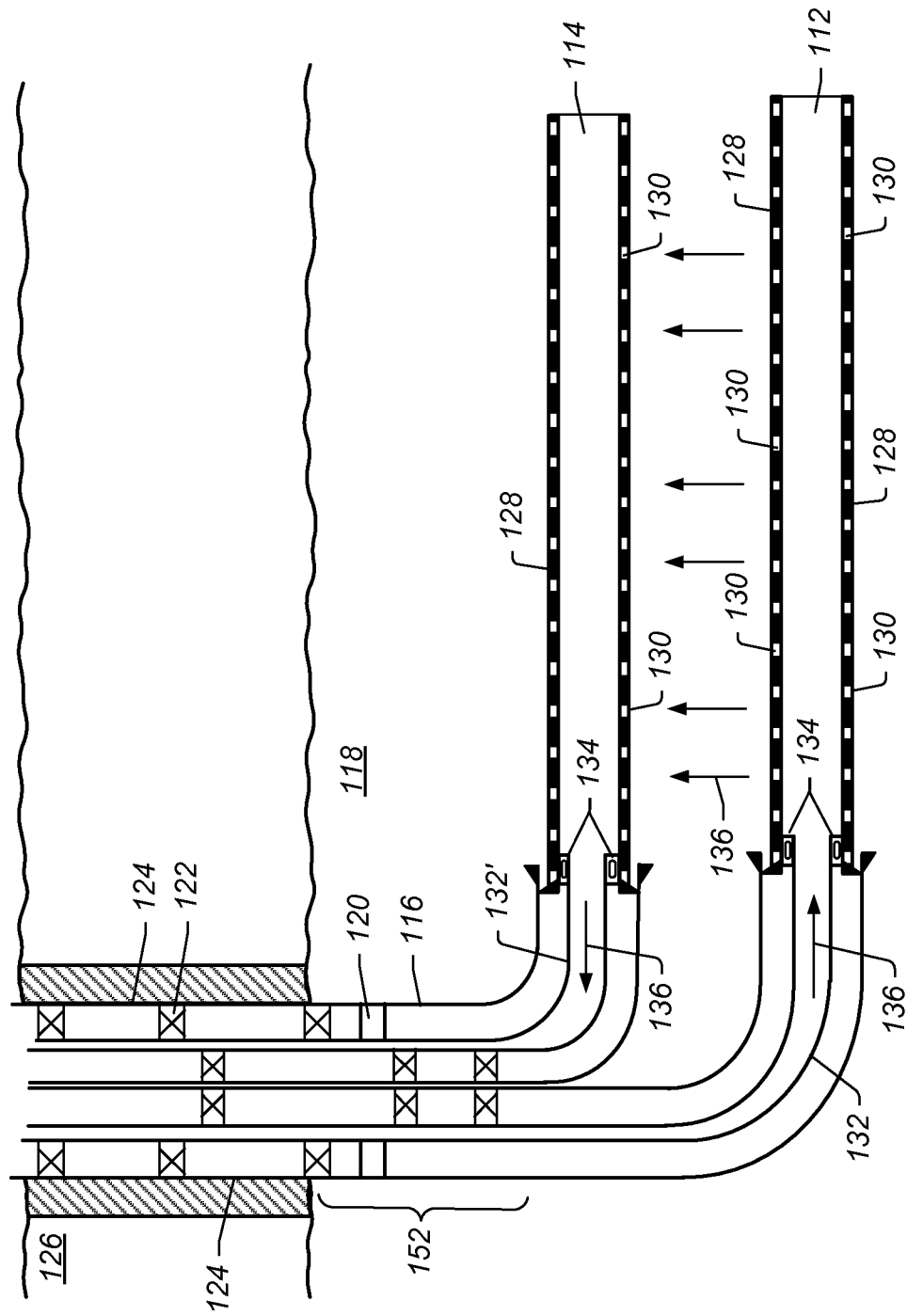


FIG. 5

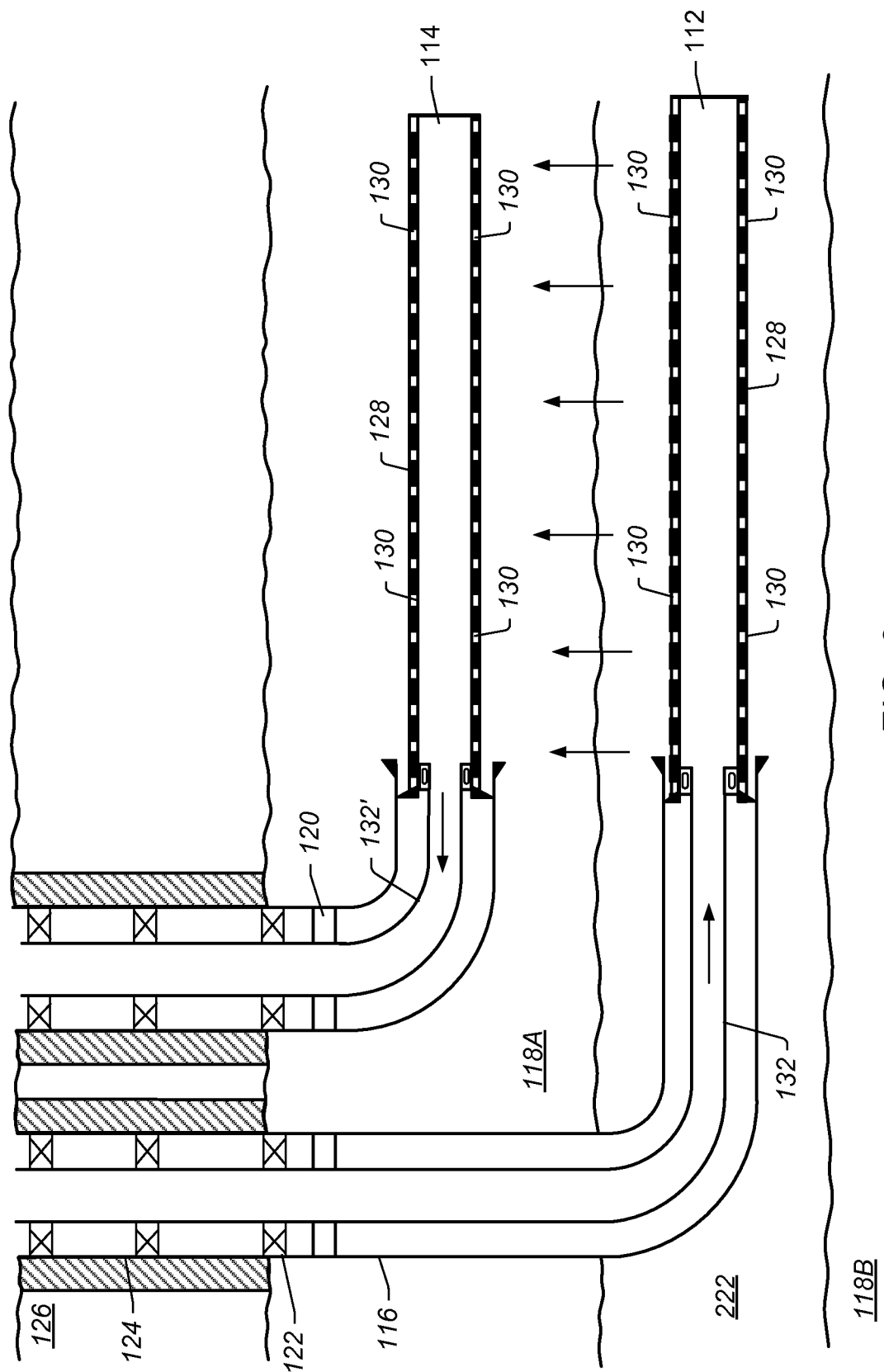


FIG. 6

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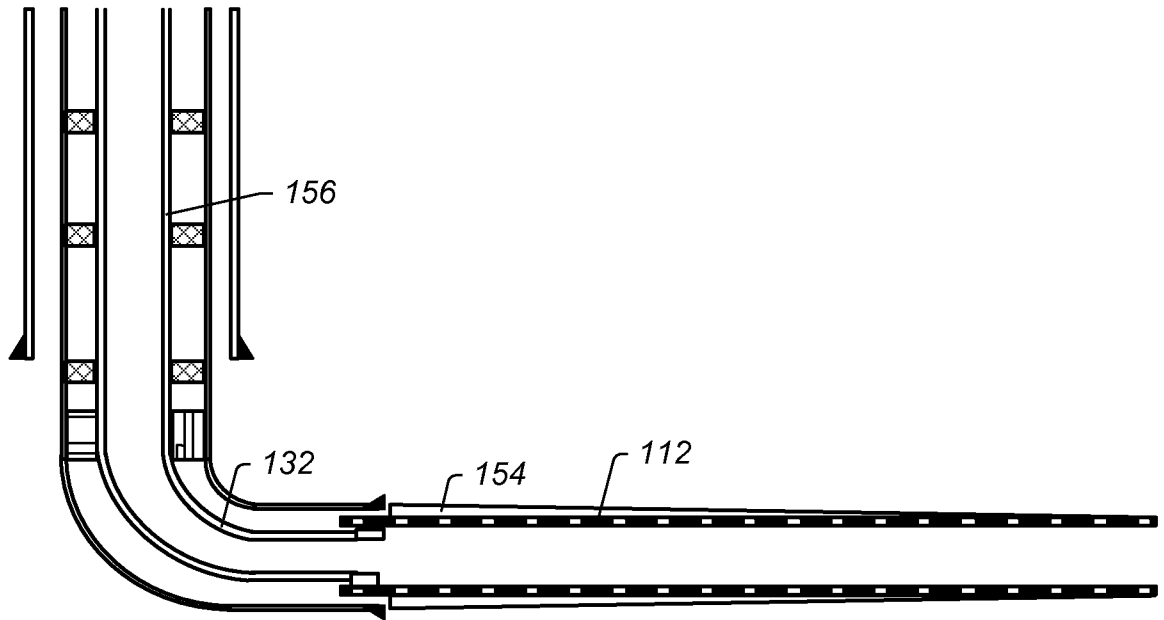


FIG. 7

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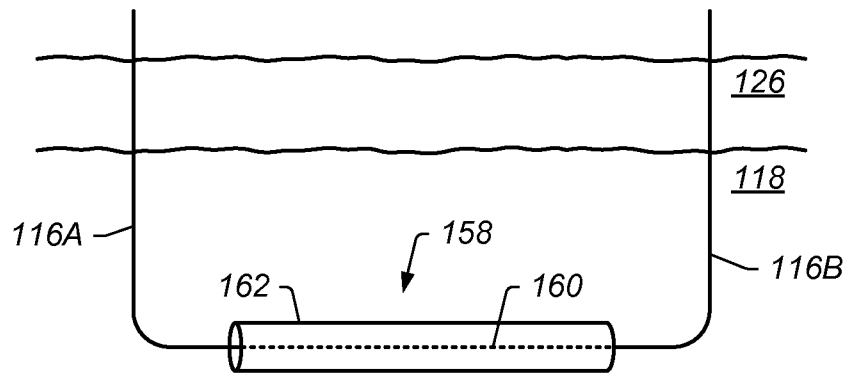


FIG. 8

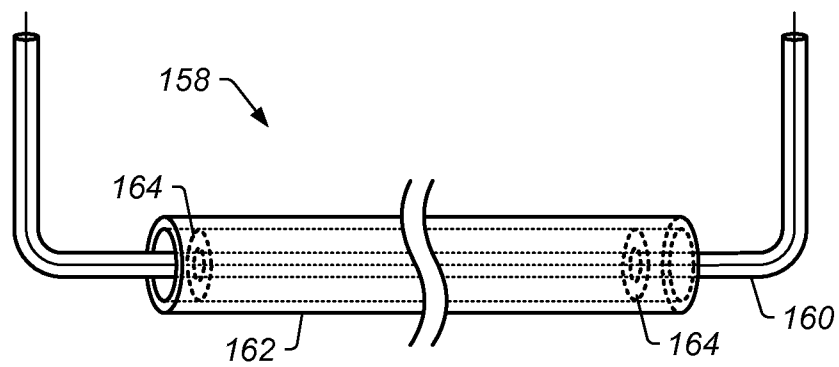


FIG. 9

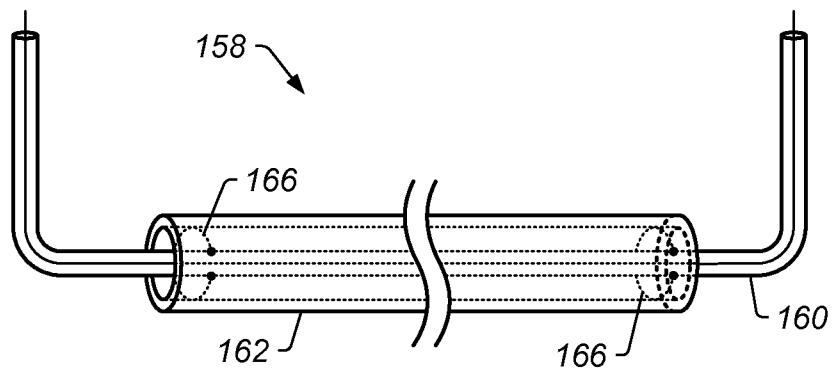


FIG. 10

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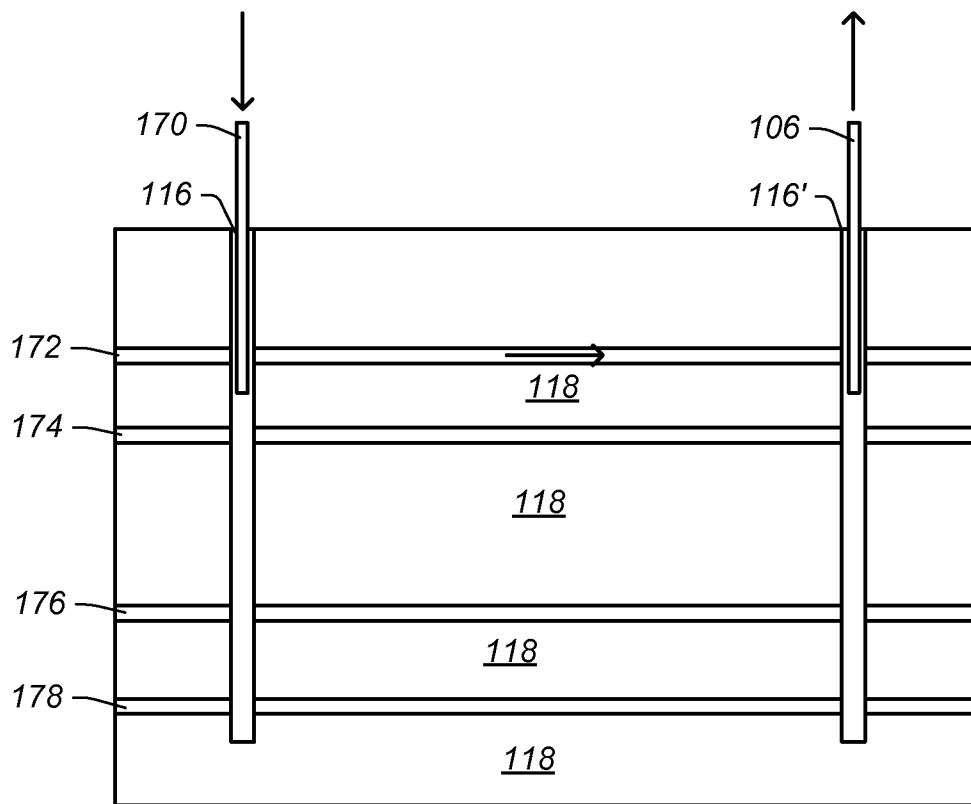


FIG. 11A

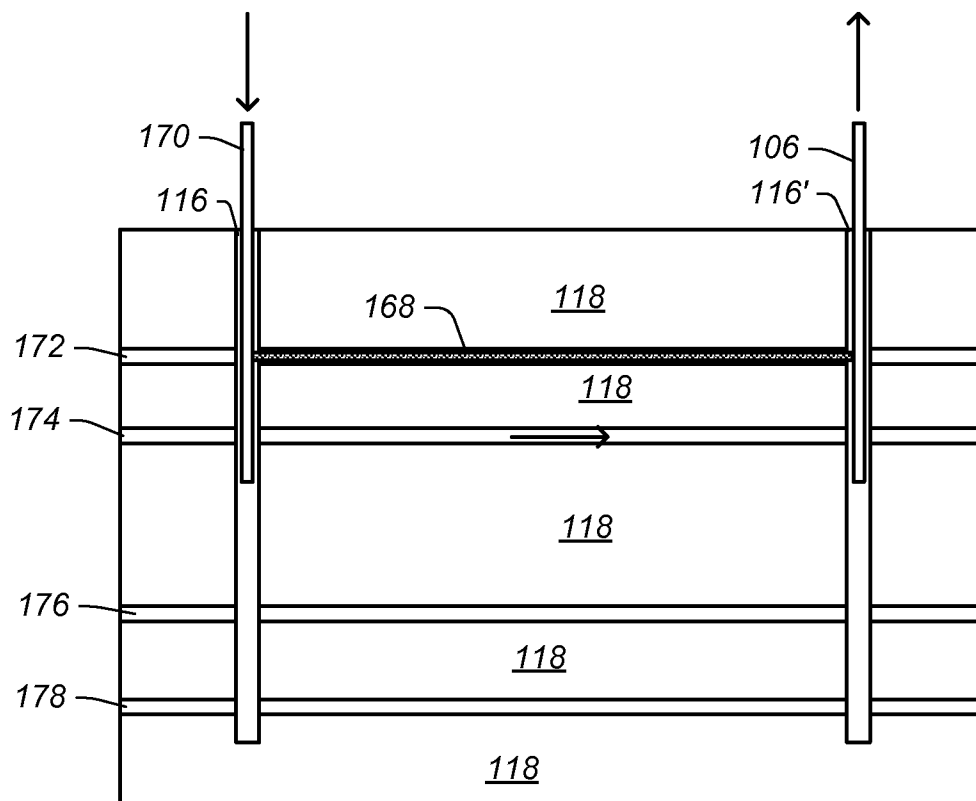


FIG. 11B

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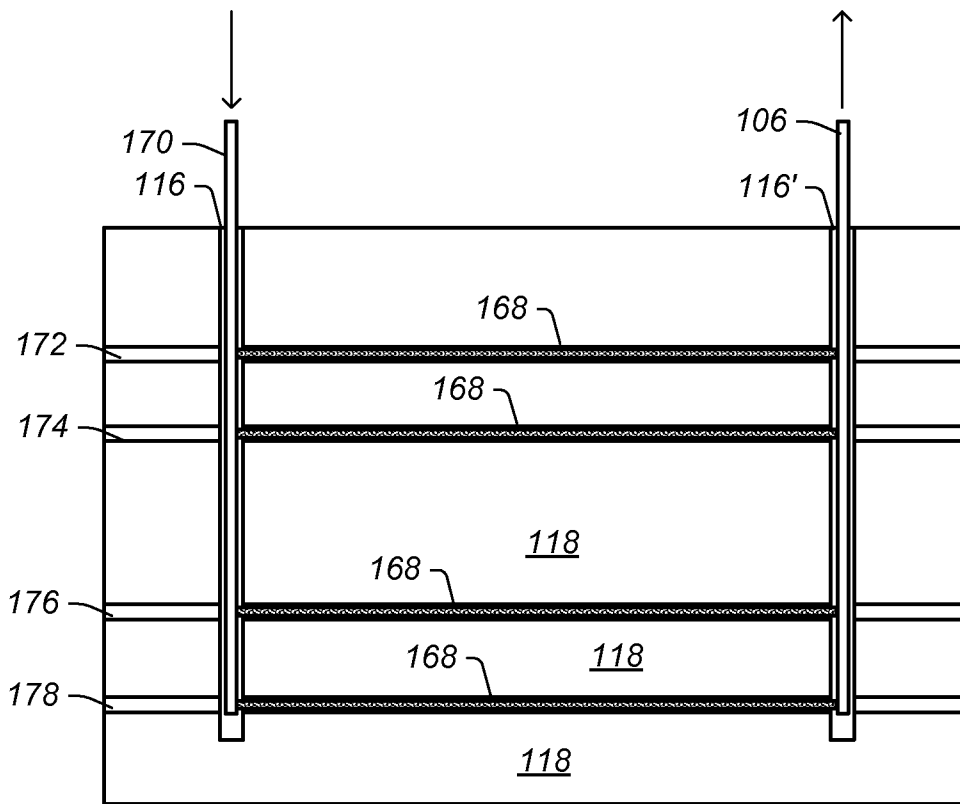


FIG. 11C

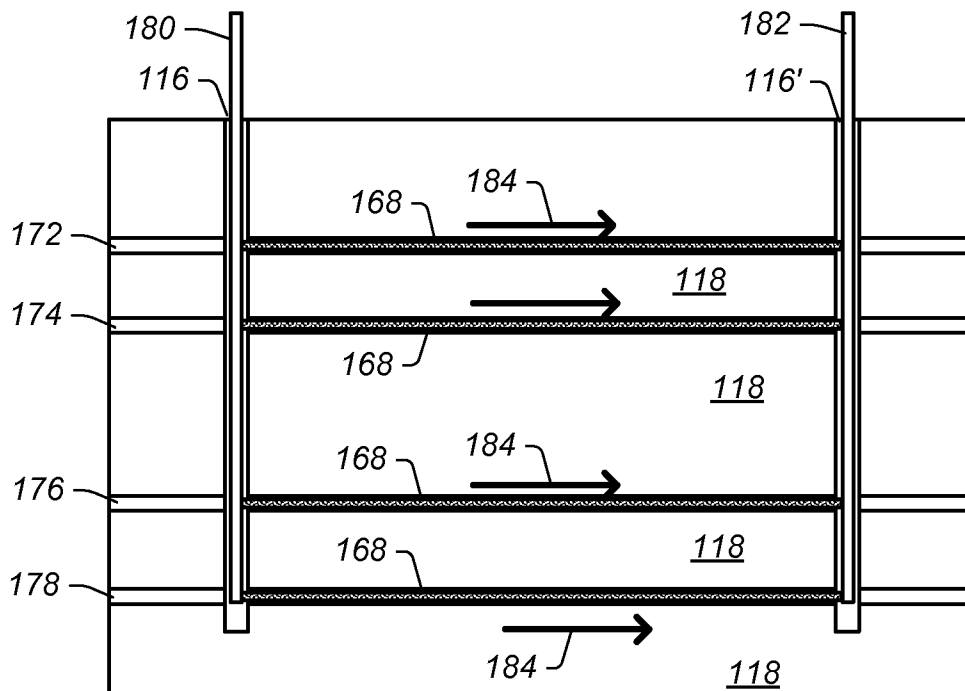


FIG. 11D

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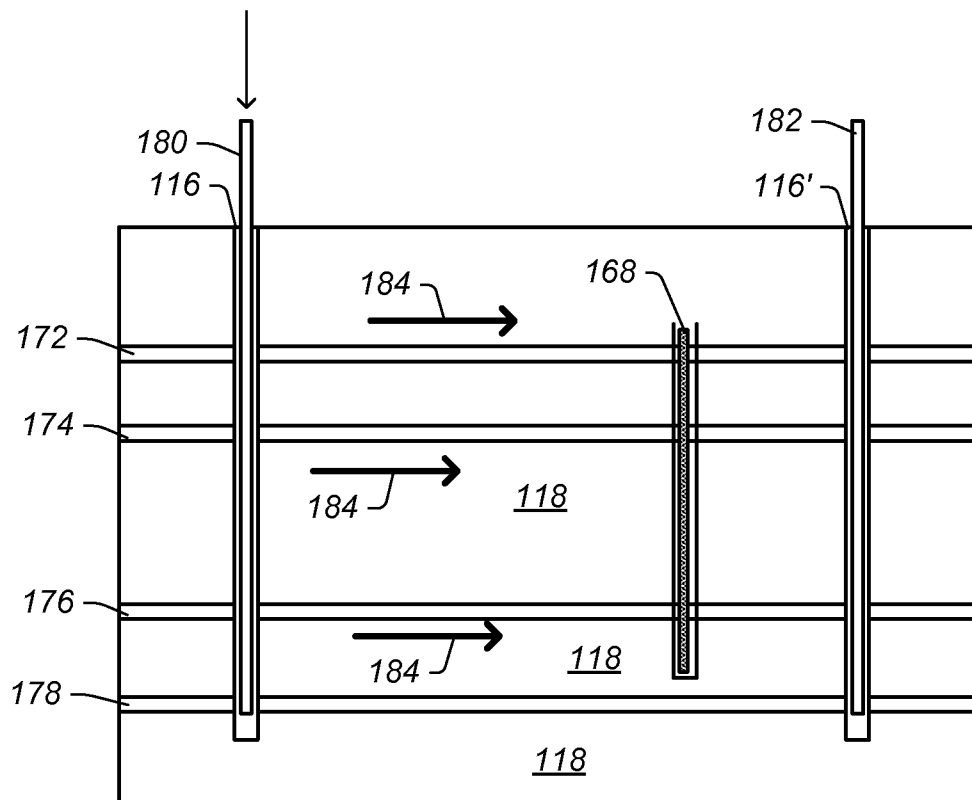


FIG. 12

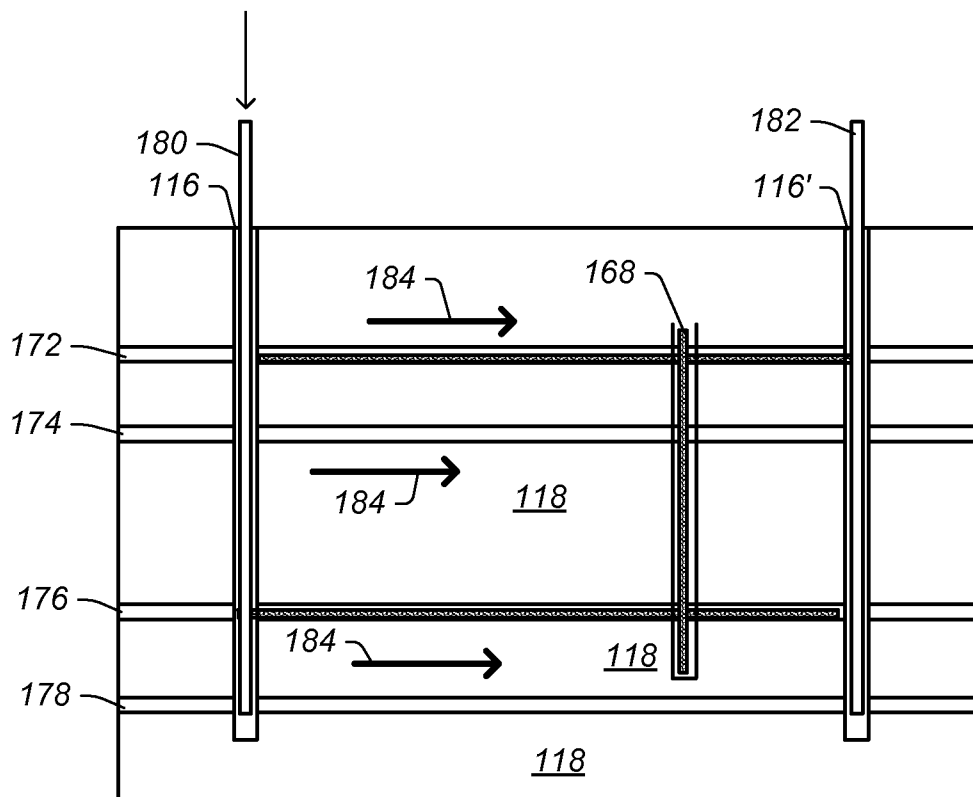


FIG. 13

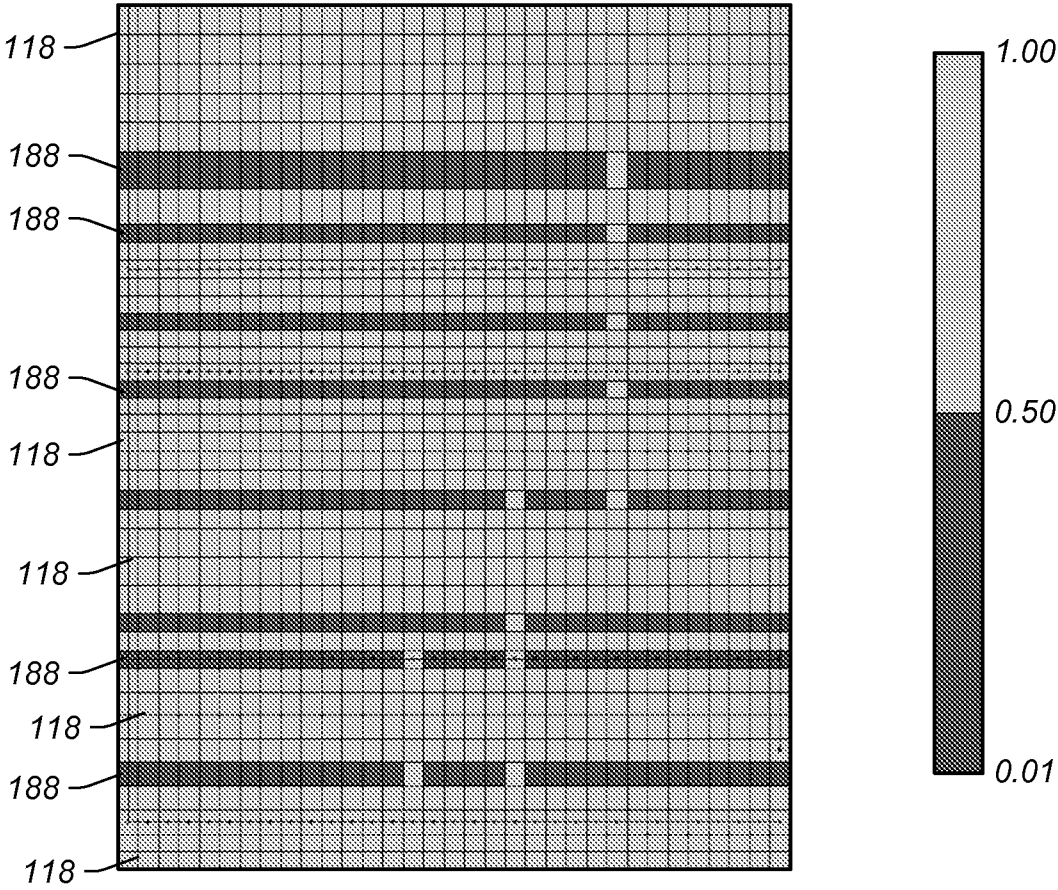


FIG. 14

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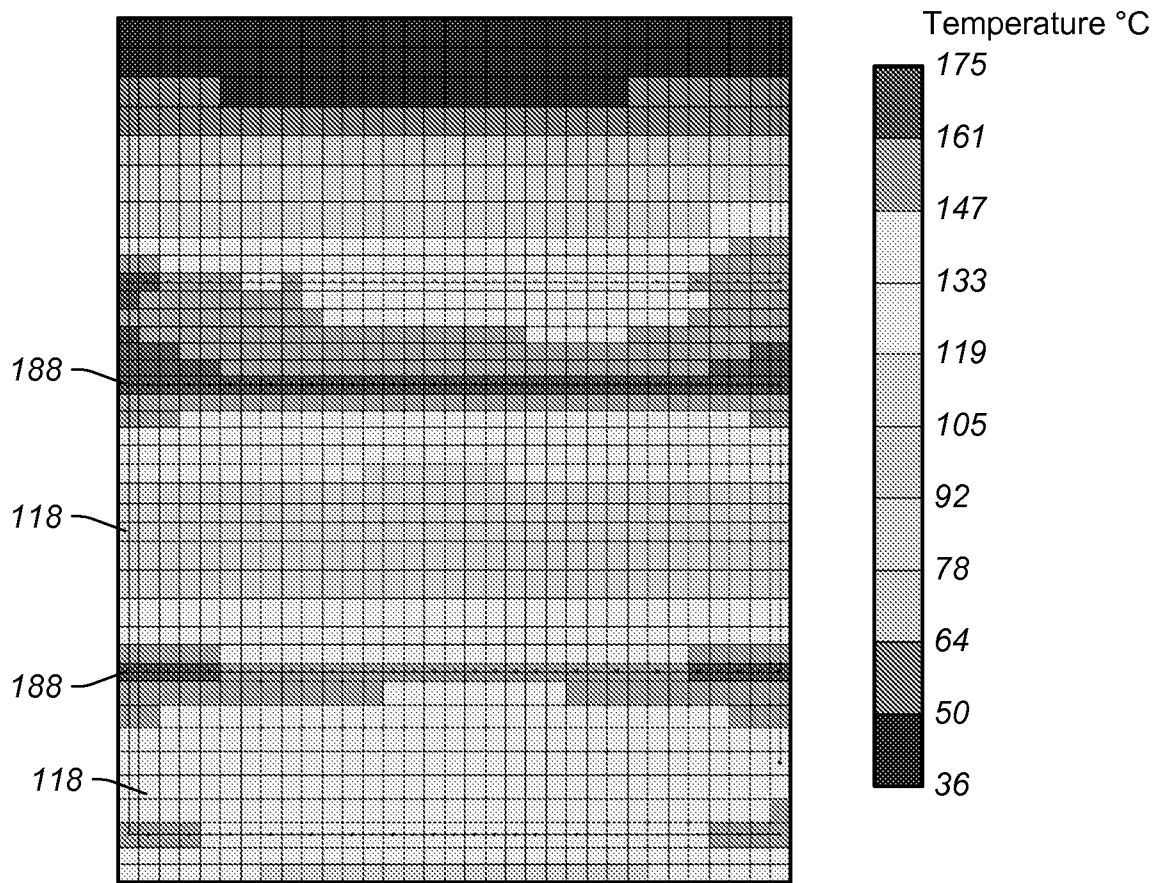


FIG. 15

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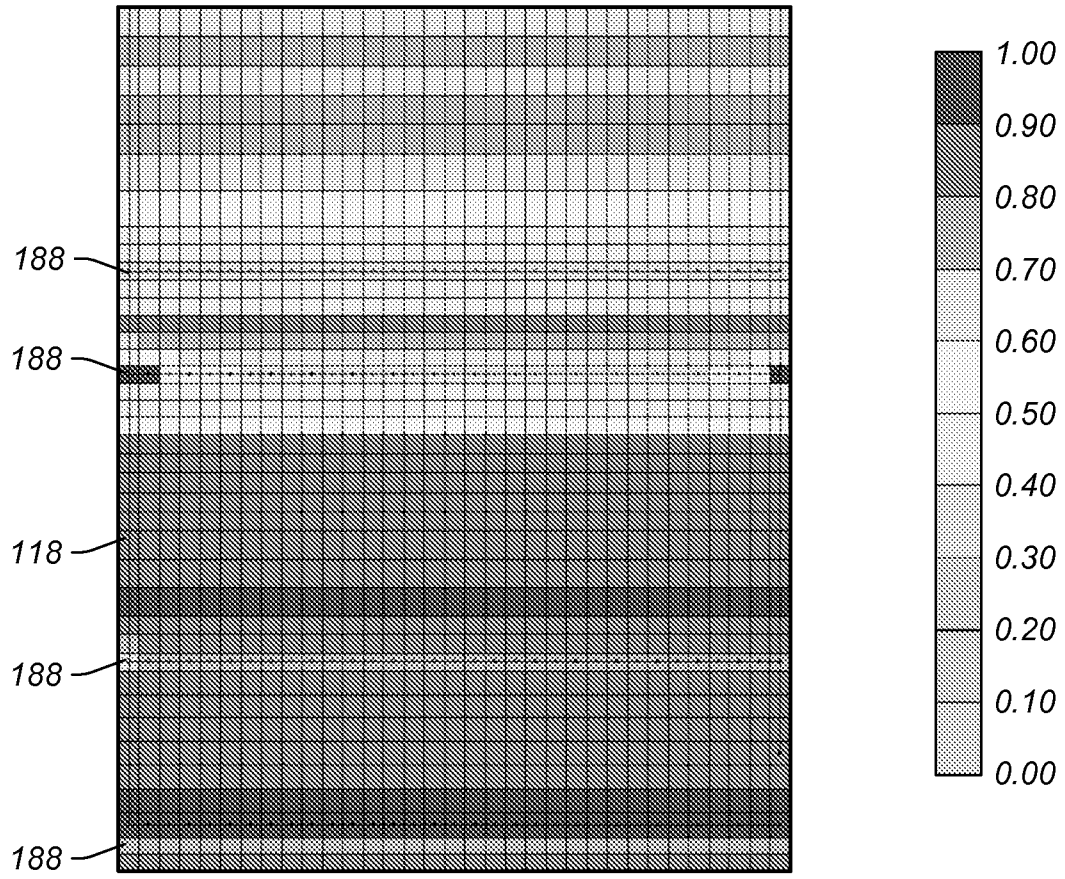


FIG. 16

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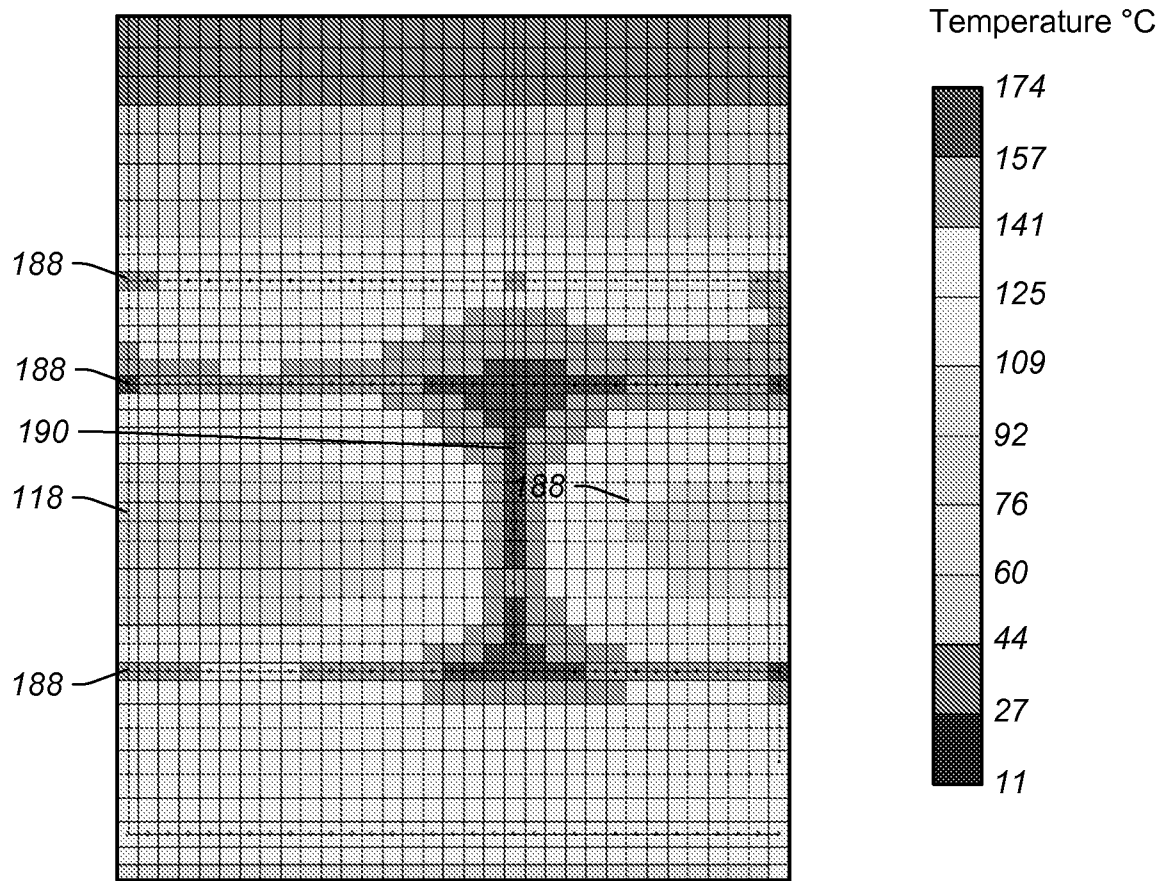


FIG. 17

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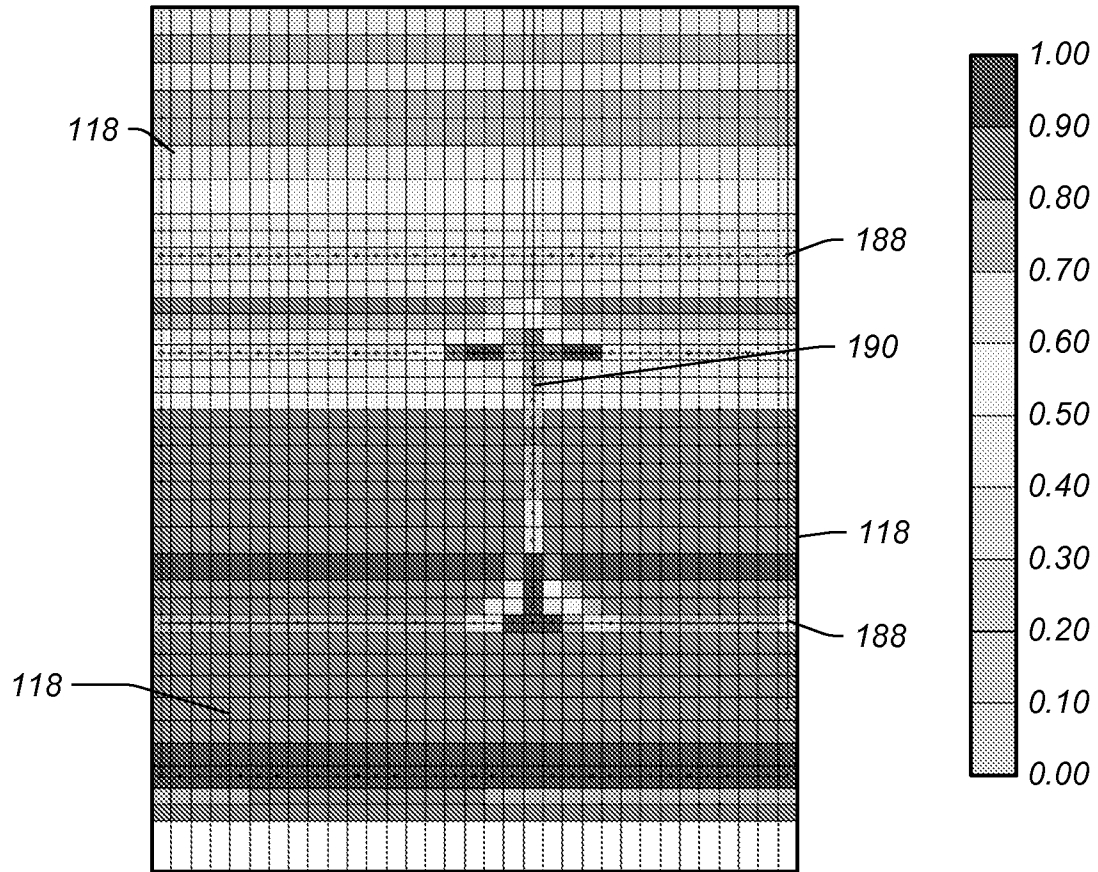


FIG. 18

INTERNATIONAL SEARCH REPORT

International application No.

PCT/US2011/055218

A. CLASSIFICATION OF SUBJECT MATTER

IPC(8) - E21B 36/00 (2012.01)

USPC - 166/302

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)

IPC(8) - E21B 36/00 (2012.01)

USPC - 166/60, 61, 248, 302, 372, 371; 219/415, 418, 764, 770

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)

PatBase and Google Patents

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 2010/0101794 A1 (RYAN) 29 April 2010 (29.04.2010) entire document	1, 3, 10, 21
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Y		2, 4-9, 11-20
Y	US 2010/0101793 A1 (SYMINGTON et al) 29 April 2010 (29.04.2010) entire document	2, 4-9, 11-20
Y	US 2007/0114020 A1 (BREKKE) 24 May 2007 (24.05.2007) entire document	19

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


* Special categories of cited documents:

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"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

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

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

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

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

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

"&" document member of the same patent family

Date of the actual completion of the international search

07 February 2012

Date of mailing of the international search report

22 FEB 2012

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