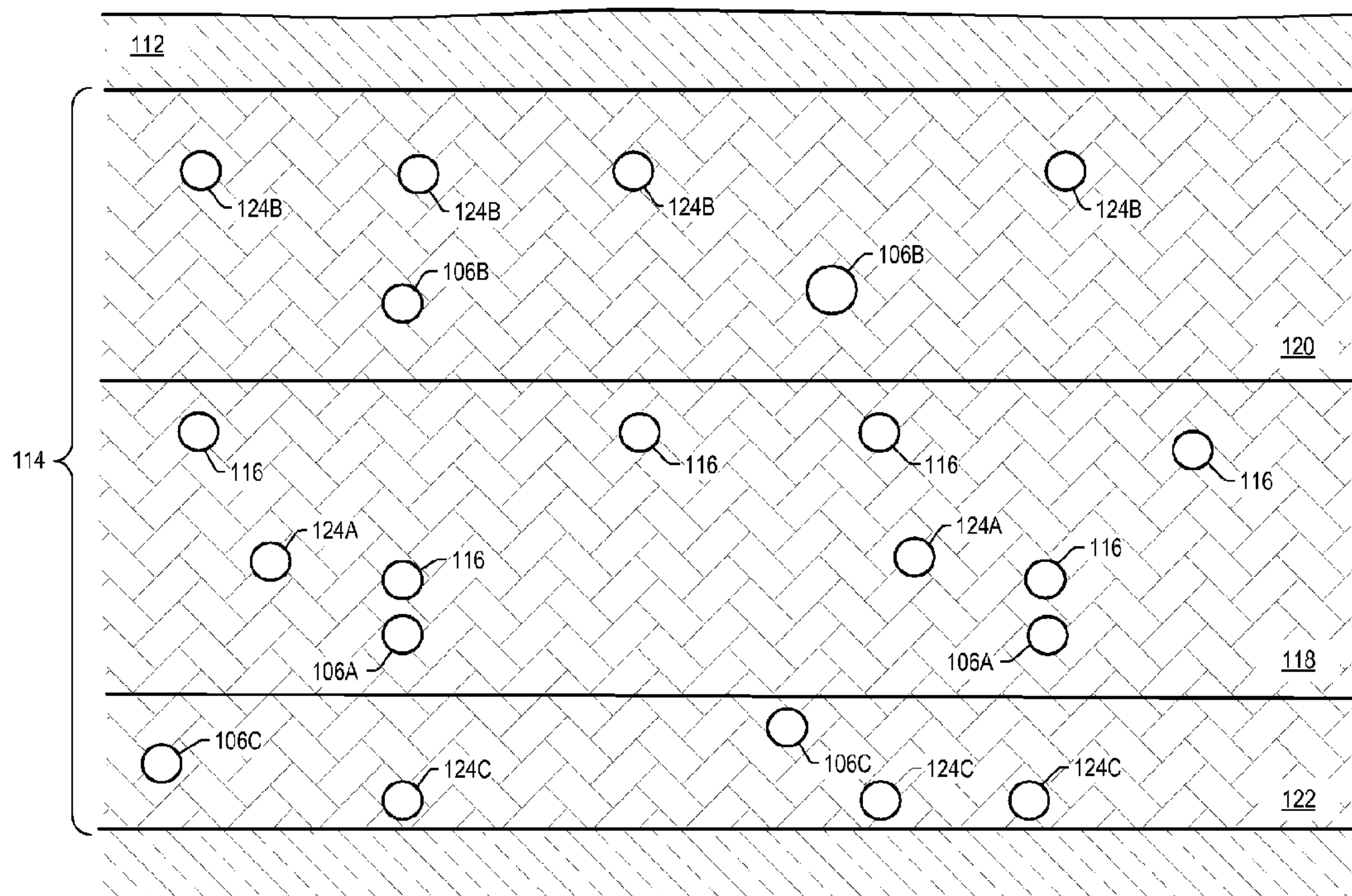




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FORMATION CONTENANT DES HYDROCARBURES
(54) Title: IN SITU RECOVERY FROM RESIDUALLY HEATED SECTIONS IN A HYDROCARBON CONTAINING
FORMATION



(57) Abrégé/Abstract:

Methods of treating a tar sands formation is described herein. The methods may include providing heat to a first section of a hydrocarbon layer in the formation from a plurality of heaters located in the first section of the formation. Heat is transferred from the heaters so that at least a first section of the formation reaches a selected temperature. At least a portion of residual heat from the first section transfers from the first section to a second section of the formation. At least a portion of hydrocarbons in the second section are mobilized by providing a solvation fluid and/or a pressurizing fluid to the second section of the formation.



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(54) Title: IN SITU RECOVERY FROM RESIDUALLY HEATED SECTIONS IN A HYDROCARBON CONTAINING FORMATION

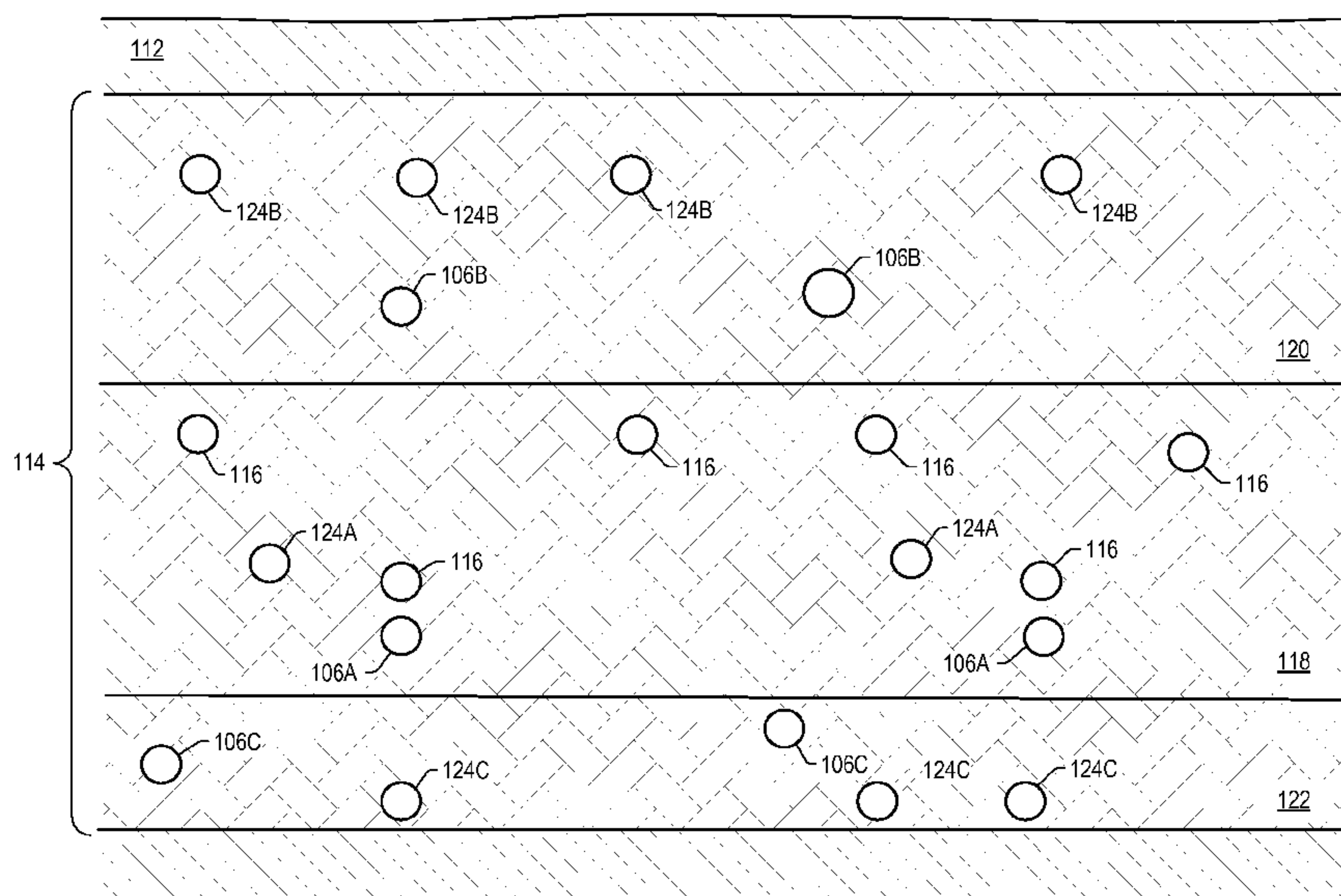


FIG. 2

(57) Abstract: Methods of treating a tar sands formation is described herein. The methods may include providing heat to a first section of a hydrocarbon layer in the formation from a plurality of heaters located in the first section of the formation. Heat is transferred from the heaters so that at least a first section of the formation reaches a selected temperature. At least a portion of residual heat from the first section transfers from the first section to a second section of the formation. At least a portion of hydrocarbons in the second section are mobilized by providing a solvation fluid and/or a pressurizing fluid to the second section of the formation.

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5 IN SITU RECOVERY FROM RESIDUALLY HEATED SECTIONS IN A
 HYDROCARBON CONTAINING FORMATION

BACKGROUND

1. Field of the Invention

10 [0001] The present invention relates generally to methods for production of hydrocarbons, hydrogen, and/or other products from various subsurface formations such as hydrocarbon containing formations.

2. Description of Related Art

15 [0002] Hydrocarbons obtained from subterranean formations are often used as energy resources, as feedstocks, and as consumer products. Concerns over depletion of available hydrocarbon resources have led to development of processes for more efficient recovery, processing and/or use of available hydrocarbon resources. For example, application of heat, steam, hot gases and/or liquids to hydrocarbon formations to mobilize and/or produce formation fluids is described in U.S. Patent Nos. 4,530,401 to Hartman et al.; 5,211,230 to
20 Ostapovich et al.; 5,339,897 to Leaute et al.; 5,046,559 to Glandt; 5,054,551 to Duerksen; 5,060,726 to Glandt et al.; 5,392,854 to Vinegar et al.; 6,910,536 to Wellington et al.; 6,981,548 to Wellington et al.; 7,073,578 to Vinegar et al.; 7,121,342 to Vinegar et al.; 7320364 to Fairbanks et al., and U.S. Published Patent Application Nos. 2007-0133960 to Vinegar et al. and 2007-0131427 to Li et al.

25 [0003] Large deposits of heavy hydrocarbons (heavy oil and/or tar) contained in relatively permeable formations (for example in tar sands) are found in North America, South America, Africa, and Asia. Tar can be surface-mined and upgraded to lighter hydrocarbons such as crude oil, naphtha, kerosene, and/or gas oil. Surface milling processes may further separate the bitumen from sand. The separated bitumen may be
30 converted to light hydrocarbons using conventional refinery methods. Mining and upgrading tar sand is usually substantially more expensive than producing lighter hydrocarbons from conventional oil reservoirs.

35 [0004] Enhanced hydrocarbon recovery methods may be used to produce additional hydrocarbons from portions of the formation treated using in situ heat treatment processes, solvating fluids and/or pressurizing fluids. Systems and methods for enhanced hydrocarbons recovery are described in U.S. Patent Nos. 3,943,160 to Farmer, III et al.; 3,946,812 to Gale et al.; 4,077,471 to Shupe et al.; 4,216,079 to Newcombe; 5,318,709 to

5 Wuest et al.; 5,723,423 to Van Slyke; 6,022,834 to Hsu et al.; 6,269,881 to Chou et al.; and 7,055,602 to Shpakoff et al.

[0005] Addition of a hydrogen donating solvent, steam and methane to a formation is described in U.S. Patent No. 5,891,829 to Vallejos et al. Vallejos describes a downhole hydroconversion process that improves the viscosity, API gravity, and distillate proportions
10 of heavy crude oils by employing a hydrogen donor, methane, and steam downhole where the mineral formation downhole acts as a catalyst for the hydroconversion process.

[0006] Since steam production requires energy and since maintaining a high steam temperature is difficult in deep portions of the formation, using heat from a heated portion of a hydrocarbon containing formation as a heat source for recovery of hydrocarbons from
15 other portions of the hydrocarbon containing formation may be advantageous.

SUMMARY

[0007] Embodiments described herein generally relate to systems and methods for treating a subsurface formation. In some embodiments, the systems, methods, and/or heaters are used for treating a subsurface formation.

20 [0008] The invention advantageously provides a method of treating a tar sands formation that includes providing heat to a first section of a hydrocarbon layer in the formation from a plurality of heaters located in the first section of the formation; allowing the heat to transfer from the heaters so that at least a first section of the formation reaches a selected temperature; allowing at least a portion of residual heat from the first section to transfer
25 from the first section to a second section of the formation; and mobilizing at least a portion of hydrocarbons in the second section by providing a solvation fluid and/or a pressurizing fluid to the second section of the formation.

[0009] The invention provides a method of treating a tar sands formation, that includes providing heat to at least part of the formation from a plurality of heaters located in the
30 formation; allowing the heat to transfer from the heaters so that at least a portion of the formation reaches a selected temperature; allowing fluids to gravity drain to a bottom portion of the formation; producing a substantial portion of the drained fluids from one or more production wells located at or proximate the bottom portion of the formation, wherein at least a majority of the produced fluids are condensable hydrocarbons; reducing the
35 pressure in the formation to a selected pressure after the portion of the formation reaches the selected temperature and after producing a majority of the condensable hydrocarbons in the portion of the formation; providing a solvation fluid and/or a pressurizing fluid to the

portion of the formation, wherein the solvation fluid solvates at least a portion or remaining condensable hydrocarbons in the part of the formation to form a mixture of solvation fluid and condensable hydrocarbons; and mobilizing the mixture.

5 [0009a] In accordance with one aspect of the present invention, there is provided a method of treating a tar sands formation, comprising: providing heat to a first section of a hydrocarbon layer in the formation from a plurality of heaters located in the first section of the formation; allowing the heat to transfer from the heaters so that at least the first section of the formation reaches a selected temperature; allowing at least a portion of residual heat from the heated first section to transfer from the heated first section to a second section of the formation; heating the unheated portion of the second section to an average temperature of at least 50°C with the residual heat from the first section; mobilizing at least a portion of hydrocarbons in the second section by providing at least one of a solvation fluid and a pressurizing fluid to the second section of the formation; and producing a mixture from the second section, wherein the mixture comprises mobilized hydrocarbons and solvation fluid.

15 [0009b] In accordance with another aspect of the present invention, there is provided a method of treating a hydrocarbon containing formation, comprising: providing heat to a first section of a hydrocarbon layer in the formation from a plurality of heaters located in the first section of the formation; allowing the heat to transfer from the heaters so that at least the first section of the formation reaches a selected temperature; allowing at least a portion of residual heat from the heated first section to transfer from the heated first section to an unheated portion of a second section of the formation; heating the unheated portion of the second section to an average temperature of at least 50°C with the residual heat from the first section; mobilizing at least a portion of hydrocarbons in the heated second section by providing a solvation fluid to the second section of the formation; and producing hydrocarbons from the first section, wherein the produced hydrocarbons comprise hydrocarbons from the second section and solvation fluid.

10 [0010] The invention provides for a method for treating a hydrocarbon formation that includes providing heat to a portion of the formation from one or more heaters located in the formation; introducing a hydrogen donating solvation fluid to the portion of the formation; contacting at least a portion of the formation fluids with the hydrogen donating solvation fluid at a temperature of at least 175 °C to produce a mixture comprising upgraded hydrocarbons, formation fluids, hydrogen donating solvation, and dehydrogenated solvation fluid; and producing at least some of the mixture from the
15 formation.

[0011] The invention provides for a method for treating a tar sands formation with one or more karsted layers that includes providing heat from one or more heaters to at least one first karsted layer comprising hydrocarbons and being vertically above at least one second karsted layer, wherein the second karsted layer has a lower volume percent of
20 hydrocarbons per volume percent of rock than the first karsted layer providing heat to the second karsted layer so that at least some hydrocarbons in the second karsted layer are mobilized, and at least some of the mobilized hydrocarbons in the second karsted layer move to the first karsted layer; and producing hydrocarbon fluids from the first karsted layer.

25 [0012] Hydrocarbon compositions may be obtained by methods described herein.

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

30 [0014] In further embodiments, additional features may be added to the specific embodiments described herein.

BRIEF DESCRIPTION OF THE DRAWINGS

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

35 [0016] FIG. 1 shows a schematic view of an embodiment of a portion of an in situ heat treatment system for treating a hydrocarbon containing formation.

5 [0017] FIG. 2 depicts a side view representations of embodiments for producing mobilized fluids from a hydrocarbon formation heated by residual heat.

[0018] FIG. 3 depicts a side view representations of other embodiment for producing mobilized fluids from a hydrocarbon formation heated by residual heat.

[0019] While the invention is susceptible to various modifications and alternative forms,
 10 specific embodiments thereof are shown by way of example in the drawings and may herein be described in detail. The drawings may not be to scale. It should be understood, however, that the drawings and detailed description thereto are not intended to limit the invention to the particular form disclosed. The scope of the claims should not be limited by the preferred embodiments set forth in the examples, but should be given the broadest
 15 interpretation consistent with the description as a whole.

DETAILED DESCRIPTION

[0020] It has been advantageously found that hydrocarbon fluids may be produced from residually heated sections and/or inaccessible sections of a hydrocarbon containing formation. Embodiments described herein generally relate to systems, methods, and heaters
 20 for treating a subsurface formation.

[0021] “API gravity” refers to API gravity at 15.5 °C (60 °F). API gravity is as determined by ASTM Method D6822 or ASTM Method D1298.

[0022] “Bromine number” refers to a weight percentage of olefins in grams per 100 gram of portion of the produced fluid that has a boiling range below 246 °C and testing the
 25 portion using ASTM Method D1159.

[0023] “Cracking” refers to a process involving decomposition and molecular recombination of organic compounds to produce a greater number of molecules than were initially present. In cracking, a series of reactions take place accompanied by a transfer of hydrogen atoms between molecules. For example, naphtha may undergo a thermal
 30 cracking reaction to form ethene and H₂.

[0024] “Fluid pressure” is a pressure generated by a fluid in a formation. “Lithostatic pressure” (sometimes referred to as “lithostatic stress”) is a pressure in a formation equal to a weight per unit area of an overlying rock mass. “Hydrostatic pressure” is a pressure in a formation exerted by a column of water.

35 [0025] A “formation” includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. “Hydrocarbon layers” refer to layers in the formation that contain hydrocarbons. The hydrocarbon layers may

5 contain non-hydrocarbon material and hydrocarbon material. The “overburden” and/or the
“underburden” include one or more different types of impermeable materials. For
example, the overburden and/or underburden may include rock, shale, mudstone, or
wet/tight carbonate. In some embodiments of in situ heat treatment processes, the
overburden and/or the underburden may include a hydrocarbon containing layer or
10 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
15 cases, the overburden and/or the underburden may be somewhat permeable.

[0026] “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
20 flow as a result of thermal treatment of the formation. “Produced fluids” refer to fluids
removed from the formation.

[0027] A “heat source” is any system for providing heat to at least a portion of a formation
substantially by conductive and/or radiative heat transfer. For example, a heat source may
include electric heaters such as an insulated conductor, an elongated member, and/or a
25 conductor disposed in a conduit. A heat source may also include systems that generate
heat by burning a fuel external to or in a formation. The systems may be surface burners,
downhole gas burners, flameless distributed combustors, and natural distributed
combustors. In some embodiments, heat provided to or generated in one or more heat
sources may be supplied by other sources of energy. The other sources of energy may
30 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 electric resistance heaters,
some heat sources may provide heat from combustion, and some heat sources may provide
35 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

5 also include a heater that provides heat to a zone proximate and/or surrounding a heating location such as a heater well.

[0028] 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
10 thereof.

[0029] “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
15 asphaltites. Hydrocarbons may be located in or adjacent to mineral matrices in the earth. Matrices may include, but are not limited to, sedimentary rock, sands, silicilytes, carbonates, diatomites, and other porous media. “Hydrocarbon fluids” are fluids that include hydrocarbons. Hydrocarbon fluids may include, entrain, or be entrained in non-hydrocarbon fluids such as hydrogen, nitrogen, carbon monoxide, carbon dioxide,
20 hydrogen sulfide, water, and ammonia.

[0030] “Heavy hydrocarbons” are viscous hydrocarbon fluids. Heavy hydrocarbons may include highly viscous hydrocarbon fluids such as heavy oil, tar, and/or asphalt. Heavy hydrocarbons may include carbon and hydrogen, as well as smaller concentrations of sulfur, oxygen, and nitrogen. Additional elements may also be present in heavy
25 hydrocarbons in trace amounts. Heavy hydrocarbons may be classified by API gravity. Heavy hydrocarbons generally have an API gravity below about 20°. Heavy oil, for example, generally has an API gravity of about 10-20°, whereas tar generally has an API gravity below about 10°. The viscosity of heavy hydrocarbons is generally greater than about 100 centipoise at 15 °C. Heavy hydrocarbons may include aromatics or other
30 complex ring hydrocarbons.

[0031] Heavy hydrocarbons may be found in a relatively permeable formation. The relatively permeable formation may include heavy hydrocarbons entrained in, for example, sand or carbonate. “Relatively permeable” is defined, with respect to formations or portions thereof, as an average permeability of 10 millidarcy or more (for example, 10 or
35 100 millidarcy). “Relatively low permeability” is defined, with respect to formations or portions thereof, as an average permeability of less than about 10 millidarcy. One darcy is

5 equal to about 0.99 square micrometers. An impermeable layer generally has a permeability of less than about 0.1 millidarcy.

[0032] Certain types of formations that include heavy hydrocarbons may also include, but are not limited to, natural mineral waxes, or natural asphaltites. “Natural mineral waxes” typically occur in substantially tubular veins that may be several meters wide, several
10 kilometers long, and hundreds of meters deep. “Natural asphaltites” include solid hydrocarbons of an aromatic composition and typically occur in large veins. In situ recovery of hydrocarbons from formations such as natural mineral waxes and natural asphaltites may include melting to form liquid hydrocarbons and/or solution mining of hydrocarbons from the formations.

15 [0033] 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.

[0034] 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.

[0035] “Karst” is a subsurface shaped by the dissolution of a soluble layer or layers of
25 bedrock, usually carbonate rock such as limestone or dolomite. The dissolution may be caused by meteoric or acidic water. The Grosmont formation in Alberta, Canada is an example of a karst (or “karsted”) carbonate formation.

[0036] “P (peptization) value” or “P-value” refers to a numerical value which represents the flocculation tendency of asphaltenes in a fluid. P-value is determined by ASTM
30 method D7060.

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

35 [0038] “Pyrolyzation fluids” or “pyrolysis products” refers to fluid produced substantially during pyrolysis of hydrocarbons. Fluid produced by pyrolysis reactions may mix with other fluids in a formation. The mixture would be considered pyrolyzation fluid or

- 5 pyrolyzation product. As used herein, “pyrolysis zone” refers to a volume of a formation (for example, a relatively permeable formation such as a tar sands formation) that is reacted or reacting to form a pyrolyzation fluid.
- [0039] “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
- 10 location between the heat sources is influenced by the heat sources.
- [0040] “Tar” is a viscous hydrocarbon that generally has a viscosity greater than about 10,000 centipoise at 15 °C. The specific gravity of tar generally is greater than 1.000. Tar may have an API gravity less than 10°.
- [0041] A “tar sands formation” is a formation in which hydrocarbons are predominantly
- 15 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.
- 20 [0042] “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.
- [0043] “Upgrade” refers to increasing the quality of hydrocarbons. For example, upgrading heavy hydrocarbons may result in an increase in the API gravity of the heavy hydrocarbons.
- 25 [0044] “Visbreaking” refers to the untangling of molecules in fluid during heat treatment and/or to the breaking of large molecules into smaller molecules during heat treatment, which results in a reduction of the viscosity of the fluid.
- [0045] “Viscosity” refers to kinematic viscosity at 40 °C unless specified. Viscosity is as determined by ASTM Method D445.
- 30 [0046] “VGO” or “vacuum gas oil” refers to hydrocarbons with a boiling range distribution between 343 °C and 538 °C at 0.101 MPa. VGO content is determined by ASTM Method D5307.
- [0047] A “vug” is a cavity, void or large pore in a rock that is commonly lined with mineral precipitates.
- 35 [0048] 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

5 referring to an opening in the formation may be used interchangeably with the term “wellbore.”

[0049] In situ production of hydrocarbons from tar sands may be accomplished by heating and/or injecting a fluid into the formation. Heaters may be used to heat a section of the formation, and hydrocarbons are produced from the formation. For example, heaters may
10 be used to heat a section of formation to pyrolysis temperatures to produce formation fluids. In some embodiments, heaters are used to heat a section of the formation to temperatures below pyrolysis temperatures to visbreak and/or mobilize fluids in the formation. In certain embodiments, a section of a formation is heated by heaters prior to, during, or after a drive process (for example, steam injection process) is used to produce
15 formation fluids.

[0050] In selecting a section of formation to be treated, the characteristics of the formation are evaluated and the areas of the formation may be selected to be produced over other areas based on the evaluation. For example, rich layers, permeable layers and/or hydrocarbon containing formation with injectivity may be selected to be treated over other
20 sections of the formation. During treatment of the selected sections, residual (waste) heat may transfer from the selected section to adjacent sections of the formation that are not being produced and/or directly heated. Production of hydrocarbon from these sections may be difficult due to insufficient temperature to mobilize and/or produce hydrocarbons in the section. In other embodiments, large quantities of hydrocarbons may be between two
25 layers of formation that have little or no injectivity, thus it is difficult to access the hydrocarbons through conventional production methods. It would be advantageous to produce fluids from residually heated sections and/or inaccessible sections to increase overall production of hydrocarbons from the formation to increase the total recovery of fluids from the formation. It would also be advantageous to use solvation and/or
30 pressurizing fluids to recover hydrocarbons from residually heated inaccessible layers of a hydrocarbon containing formation.

[0051] FIG. 1 depicts a schematic view of an embodiment of a portion of the in situ heat treatment system for treating the hydrocarbon containing formation. The in situ heat treatment system may include barrier wells 100. Barrier wells are used to form a barrier
35 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

5 embodiments, barrier wells 100 are dewatering wells. Dewatering wells may remove liquid water and/or inhibit liquid water from entering a portion of the formation to be heated, or to the formation being heated. As 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.

10 **[0052]** Heat sources 102 are placed in at least a portion of the formation. Heat sources 102 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

15 supplied to heat sources 102 through supply lines 104. Supply lines 104 may be structurally different depending on the type of heat source or heat sources used to heat the formation. Supply lines 104 for heat sources may transmit electricity for 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

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

[0053] 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

25 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.

30 **[0054]** In some embodiments, the heat source in production well 106 allows for vapor phase removal of formation fluids from the formation. Providing heating at or through the production well may: (1) inhibit condensation and/or refluxing of production fluid when such production fluid is moving in the production well proximate the overburden, (2) increase heat input into the formation, (3) increase production rate from the production

35 well as compared to a production well without a heat source, (4) inhibit condensation of high carbon number compounds (C6 and above) in the production well, and/or (5) increase formation permeability at or proximate the production well.

- 5 **[0055]** Subsurface pressure in the formation may correspond to the fluid pressure generated in the formation. As temperatures in the heated portion of the formation increase, the pressure in the heated portion may increase as a result of thermal expansion of in situ fluids, or increased fluid generation and vaporization of water. Controlling rate of fluid removal from the formation may allow for control of pressure in the formation.
- 10 Pressure in the formation may be determined at a number of different locations, such as near or at production wells, near or at heat sources, or at monitor wells.
- [0056]** In some hydrocarbon containing formations, production of hydrocarbons from the formation is inhibited until at least some hydrocarbons in the formation have been pyrolyzed. Formation fluid may be produced from the formation when the formation fluid
- 15 is of a selected quality. In some embodiments, the selected quality includes an API gravity of at least about 20°, 30°, or 40°. Inhibiting production until at least some hydrocarbons are 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
- 20 expensive equipment and/or reduce the life of production equipment.
- [0057]** After pyrolysis temperatures are reached and production from the formation is allowed, pressure in the formation may be varied to alter and/or control a composition of formation fluid produced, to control a percentage of condensable fluid as compared to non-condensable fluid in the formation fluid, and/or to control an API gravity of formation fluid
- 25 being produced. For example, decreasing pressure may result in production of a larger condensable fluid component. The condensable fluid component may contain a larger percentage of olefins.
- [0058]** 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
- 30 of greater than 20°. Maintaining increased pressure in the formation may inhibit formation subsidence during in situ heat treatment. Maintaining increased pressure may facilitate vapor phase production of fluids from the formation. Vapor phase production may allow for a reduction in size of collection conduits used to transport fluids produced from the formation. Maintaining increased pressure may reduce or eliminate the need to compress
- 35 formation fluids at the surface to transport the fluids in collection conduits to treatment facilities.

5 [0059] Maintaining increased pressure in a heated portion of the formation may surprisingly allow for production of large quantities of hydrocarbons of increased quality and of relatively low molecular weight. Pressure may be maintained so that formation fluid produced has a minimal amount of compounds above a selected carbon number. The selected carbon number may be at most 25, at most 20, at most 12, or at most 8. Some
10 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
15 periods. The significant time periods may provide sufficient time for the compounds to pyrolyze to form lower carbon number compounds.

[0060] 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
20 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
25 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 may be jet fuel, such as JP-8.

[0061] In some embodiments, karsted formations or karsted layers in formations have vugs in one or more layers of the formations. The vugs may be filled with viscous fluids such as
30 bitumen or heavy oil. In some embodiments, the karsted layers have a porosity of at least about 20 porosity units, at least about 30 porosity units, or at least about 35 porosity units. The karsted formation may have a porosity of at most about 15 porosity units, at most about 10 porosity units, or at most about 5 porosity units. Vugs filled with viscous fluids may inhibit steam or other fluids from being injected into the formation or the layers. In
35 certain embodiments, the karsted formation or karsted layers of the formation are treated using the in situ heat treatment process.

- 5 **[0062]** Heating of these formations or layers may decrease the viscosity of the viscous fluids in the vugs and allow the fluids to drain (for example, mobilize the fluids). Formations with karsted layers may have sufficient permeability so that when the viscosity of fluids (hydrocarbons) in the formation is reduced, the fluids drain and/or move through the formation relatively easily (for example, without a need for creating higher
- 10 permeability in the formation).
- [0063]** In some embodiments, the relative amount (the degree) of karst in the formation is assessed using techniques known in the art (for example, 3D seismic imaging of the formation). The assessment may give a profile of the formation showing layers or portions with varying amounts of karst in the formation. In certain embodiments, more heat is
- 15 provided to selected karsted portions of the formation than other karsted portions of the formation. In some embodiments, selective amounts of heat are provided to portions of the formation as a function of the degree of karst in the portions. Amounts of heat may be provided by varying the number and/or density of heaters in the portions with varying degrees of karst.
- 20 **[0064]** In certain embodiments, the hydrocarbon fluids in karsted portions have higher viscosities than hydrocarbons in other non-karsted portions of the formation. Thus, more heat may be provided to the karsted portions to reduce the viscosity of the hydrocarbons in the karsted portions.
- [0065]** In certain embodiments, only the karsted layers of the formation are treated using
- 25 the in situ heat treatment process. Other non-karsted layers of the formation may be used as seals for the in situ heat treatment process. For example, karsted layers with different quantities of hydrocarbons in the layers may be treated while other layers are used as natural seals for the treatment process. In some embodiments, karsted layers with low quantities of hydrocarbons as compared to the other karsted and/or non-karsted layers are
- 30 used as seals for the treatment process. The quantity of hydrocarbons in the Karsted layer may be determined using logging methods and/or Dean Stark distillation methods. The quantity of hydrocarbons may be reported as a volume percent of hydrocarbons per volume percent of rock, or as volume of hydrocarbons per mass of rock.
- [0066]** In some embodiments, karsted layers with fewer hydrocarbons are treated along
- 35 with karsted layers with more hydrocarbons. In some embodiments, karsted layers with fewer hydrocarbons are above and below a karsted layer with more hydrocarbons (the middle karsted layer). Less heat may be provided to the upper and lower karsted layers

5 than the middle karsted layer. Less heat may be provided in the upper and lower karsted layers by having greater heat spacing and/or less heaters in the upper and lower karsted layers as compared to the middle karsted layer. In some embodiments, less heating of the upper and lower karsted layers includes heating the layers to mobilization and/or visbreaking temperatures, but not to pyrolysis temperatures. In some embodiments, the upper and/or lower karsted layers are heated with heaters and the residual heat from the upper and/or lower layers transfers to the middle layer.

[0067] One or more production wells may be located in the middle karsted layer. Mobilized and/or visbroken hydrocarbons from the upper karsted layer may drain to the production wells in the middle karsted layer. Heat provided to the lower karsted layer may create a thermal expansion drive and/or a gas pressure drive in the lower karsted layer. The thermal expansion and/or gas pressure may drive fluids from the lower karsted layer to the middle karsted layer. These fluids may be produced through the production wells in the middle karsted layer. Providing some heat to the upper and lower karsted layers may increase the total recovery of fluids from the formation by, for example, 25% or more.

20 [0068] In some embodiments, the karsted layers with fewer hydrocarbons are further heated to pyrolysis temperatures after production from the karsted layer with more hydrocarbons is completed or almost completed. The karsted layers with fewer hydrocarbons may also be further treated by producing fluids through production wells located in the layers.

25 [0069] In some embodiments, a drive process, a solvent injection process and/or a pressurizing fluid process is used after the in situ heat treatment of the karsted formation or karsted layers. A drive process may include injection of a drive fluid such as steam. A drive process includes, but is not limited to, a steam injection process such as cyclic steam injection, a steam assisted gravity drainage process (SAGD), and a vapor solvent and SAGD process. A drive process may drive fluids from one portion of the formation towards a production well.

30 [0070] A solvent injection process may include injection of a solvating fluid. A solvating fluid includes, but is not limited to, water, emulsified water, hydrocarbons, surfactants, alkaline water solutions (for example, sodium carbonate solutions), caustic, polymers, carbon disulfide, carbon dioxide, or mixtures thereof. The solvation fluid may mix with, solvate and/or dilute the hydrocarbons to form a mixture of condensable hydrocarbons and solvation fluids. The mixture may have a reduced viscosity as compared to the initial

5 viscosity of the fluids in the formation. The mixture may flow and/or be mobilized towards production wells in the formation.

[0071] A pressurizing process may include moving hydrocarbons in the formation by injection of a pressurized fluid. The pressurizing fluid may include, but is not limited to, carbon dioxide, nitrogen, steam, methane, and/or mixtures thereof.

10 [0072] In some embodiments, the drive process (for example, the steam injection process) is used to mobilize fluids before the in situ heat treatment process. Steam injection may be used to get hydrocarbons (oil) away from rock or other strata in the formation. The steam injection may mobilize the hydrocarbons without significantly heating the rock.

15 [0073] In some embodiments, fluid injected in the formation (for example, steam and/or carbon dioxide) may absorb heat from the formation and cool the formation depending on the pressure in the formation and the temperature of the injected fluid. In some embodiments, the injected fluid is used to recover heat from the formation. The recovered heat may be used in surface processing fluids and/or to preheat other portions of the formation using the drive process.

20 [0074] In some embodiments, heaters are used to preheat the karsted formation or karsted layers to create injectivity in the formation. In situ heat treatment of karsted formations and/or karsted layers may allow for drive fluid injection, solvent injection and/or pressurizing fluid injection where it was previously unfavorable or unmanageable. Typically, karsted formations were unfavorable for drive processes because channeling of
25 the fluid injected in the formation inhibited pressure build-up in the formation. In situ heat treatment of karsted formations may allow for injection of a drive fluid, a solvent and/or a pressurizing fluid by reducing the viscosity of hydrocarbons in the formation and allowing pressure to build in the formations without significant bypass of the fluid through channels in the formations. For example, heating a section of the formation using in situ heat
30 treatment may heat and mobilize heavy hydrocarbons (bitumen) by reducing the viscosity of the heavy hydrocarbons in the karsted layer. Some of the heated less viscous heavy hydrocarbons may flow from the karsted layer into other portions of the formation that are cooler than the heated karsted portion. The heated less viscous heavy hydrocarbons may flow through channels and/or fractures. The heated heavy hydrocarbons may cool and
35 solidify in the channels, thus creating a temporary seal for the drive fluid, solvent, and/or pressurizing fluid.

- 5 [0075] In certain embodiments, the karsted formation or karsted layers are heated to temperatures below the decomposition temperature of minerals in the formation (for example, rock minerals such as dolomite and/or clay minerals such as kaolinite, illite, or smectite). In some embodiments, the karsted formation or karsted layers are heated to temperatures of at most 400 °C, at most 450 °C, or at most 500 °C (for example, to a
10 temperature below a dolomite decomposition temperature at formation pressure). In some embodiments, the karsted formation or karsted layers are heated to temperatures below a decomposition temperature of clay minerals (such as kaolinite) at formation pressure.
- [0076] In some embodiments, heat is preferentially provided to portions of the formation with low weight percentages of clay minerals (for example, kaolinite) as compared to the
15 content of clay in other portions of the formation. For example, more heat may be provided to portions of the formation with at most 1% by weight clay minerals, at most 2% by weight clay minerals, or at most 3% by weight clay minerals than portions of the formation with higher weight percentages of clay minerals. In some embodiments, the rock and/or clay mineral distribution is assessed in the formation prior to designing a heater
20 pattern and installing the heaters. The heaters may be arranged to preferentially provide heat to the portions of the formation that have been assessed to have lower weight percentages of clay minerals as compared to other portions of the formation. In certain embodiments, the heaters are placed substantially horizontally in layers with low weight percentages of clay minerals.
- 25 [0077] Providing heat to portions with low weight percentages of clay minerals may minimize changes in the chemical structure of the clays. For example, heating clays to high temperatures may drive water from the clays and change the structure of the clays. The change in structure of the clay may adversely affect the porosity and/or permeability of the formation. If the clays are heated in the presence of air, the clays may oxidize and the
30 porosity and/or permeability of the formation may be adversely affected. Portions of the formation with a high weight percentage of clay minerals may be inhibited from reaching temperatures above temperatures that effect the chemical composition of the clay minerals at formation pressures. For example, portions of the formation with large amounts of kaolinite relative to other portions of the formation may be inhibited from reaching
35 temperatures above 240 °C. In some embodiments, portions of the formation with a high quantity of clay minerals relative to other portions of the formation may be inhibited from reaching temperatures above 200 °C, above 220 °C, above 240 °C, or above 300 °C.

- 5 **[0078]** In some embodiments, karsted formations may include water. Minerals (for example, carbonate minerals) in the formation may at least partially dissociate in the water to form carbonic acid. The concentration of carbonic acid in the water may be sufficient to make the water acidic. At pressure greater than ambient formation pressures, dissolution of minerals in the water may be enhanced, thus formation of acidic water is enhanced.
- 10 Acidic water may react with other minerals in the formation such as dolomite ($\text{MgCa}(\text{CO}_3)_2$) and increase the solubility of the minerals. Water at lower pressures, or non-acidic water, may not solubilize the minerals in the formation. Dissolution of the minerals in the formation may form fractures in the formation. Thus, controlling the pressure and/or the acidity of water in the formation may control the solubilization of
- 15 minerals in the formation. In some embodiments, other inorganic acids in the formation enhance the solubilization of minerals such as dolomite.
- [0079]** In some embodiments, the karsted formation or karsted layers are heated to temperatures above the decomposition temperature of minerals in the formation. At temperatures above the minerals decomposition temperature, the minerals may decompose
- 20 to produce carbon dioxide or other products. The decomposition of the minerals and the carbon dioxide production may create permeability in the formation and mobilize viscous fluids in the formation. In some embodiments, the produced carbon dioxide is maintained in the formation to generate a gas cap in the formation. The carbon dioxide may be allowed to rise to the upper portions of the karsted layers to generate the gas cap.
- 25 **[0080]** In certain embodiments, in situ heat treatment of the relatively permeable formation containing hydrocarbons (for example, the tar sands formation) includes heating the formation to visbreaking temperatures. For example, the formation may be heated to temperatures from 100 °C to 260 °C, from 150 °C to 250 °C, from 200 °C to 240 °C, from 205 °C to 230 °C, or from 210 °C to 225 °C. In some embodiments, the formation is
- 30 heated to a temperature of 220 °C. In certain embodiments, the formation is heated to a temperature of 230 °C. The formation may be heated to other temperatures. At visbreaking temperatures, fluids in the formation have a reduced viscosity (versus their initial viscosity at initial formation temperature) that allows fluids to flow in the formation. The reduced viscosity at visbreaking temperatures may be a permanent reduction in
- 35 viscosity as the hydrocarbons go through a step change in viscosity at visbreaking temperatures (versus heating to mobilization temperatures, which may only temporarily reduce the viscosity). The visbroken fluids may have API gravities that are relatively low

5 (for example, at most 10°, 12°, 15°, or 19° API gravity), but the API gravities are higher than the API gravity of non-visbroken fluid from the formation. The non-visbroken fluid from the formation may have an API gravity of 7° or less.

[0081] In some embodiments, heaters in the formation are operated at full power output to heat the formation to visbreaking temperatures or higher temperatures. Operating at full
10 power may rapidly increase the pressure in the formation. In certain embodiments, fluids are produced from the formation to maintain a pressure in the formation below a selected pressure as the temperature of the formation increases. In some embodiments, the selected pressure is a fracture pressure of the formation. In certain embodiments, the selected pressure is from 1000 kPa to 15000 kPa, from 2000 kPa to 10000 kPa, or from 2500 kPa to
15 5000 kPa. In certain embodiments, the selected pressure is 10000 kPa. Maintaining the pressure as close to the fracture pressure as possible may minimize the number of production wells needed for producing fluids from the formation.

[0082] In certain embodiments, treating the formation includes maintaining the temperature at or near visbreaking temperatures (as described above) during the entire
20 production phase while maintaining the pressure below the fracture pressure. The heat provided to the formation may be reduced or eliminated to maintain the temperature at or near visbreaking temperatures. Heating to visbreaking temperatures but maintaining the temperature below pyrolysis temperatures or near pyrolysis temperatures (for example, below about 230 °C) inhibits coke formation and/or higher level reactions. Heating to
25 visbreaking temperatures at higher pressures (for example, pressures near but below the fracture pressure) keeps produced gases in the liquid oil (hydrocarbons) in the formation and increases hydrogen reduction in the formation with higher hydrogen partial pressures. Heating the formation to only visbreaking temperatures also uses less energy input than heating the formation to pyrolysis temperatures.

30 [0083] Fluids produced from the formation may include visbroken fluids, mobilized fluids, and/or pyrolyzed fluids. In some embodiments, a produced mixture that includes these fluids is produced from the formation. The properties of the produced mixture may be set by the operating conditions in the formation (for example, temperature and/or pressure in the formation). In certain embodiments, the operating conditions may be selected, varied,
35 and/or maintained to produce desirable properties in hydrocarbons in the produced mixture. For example, the produced mixture may include hydrocarbons that have properties that

- 5 allow the mixture to be easily transported (for example, sent through a pipeline without adding diluent or blending the mixture and/or resulting hydrocarbons with another fluid).
- [0084] In certain embodiments, the amount of fluids produced at temperatures below visbreaking temperatures, the amount of fluids produced at visbreaking temperatures, the amount of fluids produced before reducing the pressure in the formation, and/or the amount
- 10 of upgraded or pyrolyzed fluids produced may be varied to control the quality and amount of fluids produced from the formation and the total recovery of hydrocarbons from the formation. For example, producing more fluid during the early stages of treatment (for example, producing fluids before reducing the pressure in the formation) may increase the total recovery of hydrocarbons from the formation while reducing the overall quality
- 15 (lowering the overall API gravity) of fluid produced from the formation. The overall quality is reduced because more heavy hydrocarbons are produced by producing more fluids at the lower temperatures. Producing less fluids at the lower temperatures may increase the overall quality of the fluids produced from the formation but may lower the total recovery of hydrocarbons from the formation. The total recovery may be lower
- 20 because more coking occurs in the formation when less fluid is produced at lower temperatures.
- [0085] In some embodiments, production of fluids is continued after reducing and/or turning off heating of the formation. The formation may be heated for a selected time. The formation may be heated to a selected average temperature. Production from the
- 25 formation may continue after the selected time. Continuing production may produce more fluid from the formation as fluids drain towards the bottom of the formation and/or as fluids are upgraded by passing by hot spots in the formation. In some embodiments, horizontal production wells are located at or near the bottom of the formation (or a zone of the formation) to produce fluids after heating is turned down and/or off.
- 30 [0086] In certain embodiments, formation conditions (for example, pressure and temperature) and/or fluid production are controlled to produce fluids with selected properties. For example, formation conditions and/or fluid production may be controlled to produce fluids with a selected API gravity and/or a selected viscosity. The selected API gravity and/or selected viscosity may be produced by combining fluids produced at
- 35 different formation conditions (for example, combining fluids produced at different temperatures during the treatment as described above). As an example, formation

5 conditions and/or fluid production may be controlled to produce fluids with an API gravity of about 19° and a viscosity of about 0.35 Pa·s (350 cp) at 5 °C.

[0087] In certain embodiments, a drive process (for example, a steam injection process such as cyclic steam injection, a steam assisted gravity drainage process (SAGD), a solvent injection process, a vapor solvent and SAGD process, or a carbon dioxide injection
10 process) is used to treat the tar sands formation in addition to the in situ heat treatment process. In some embodiments, heaters are used to create high permeability zones (or injection zones) in the formation for the drive process. Heaters may be used to create a mobilization geometry or production network in the formation to allow fluids to flow through the formation during the drive process. For example, heaters may be used to
15 create drainage paths between the heaters and production wells for the drive process. In some embodiments, the heaters are used to provide heat during the drive process. The amount of heat provided by the heaters may be small compared to the heat input from the drive process (for example, the heat input from steam injection).

[0088] In certain embodiments, a solvation fluid and/or pressurizing fluid are used to treat
20 the hydrocarbon formation in addition to the in situ heat treatment process. In some embodiments, a solvation fluid and/or pressurizing fluid is used after the hydrocarbon formation has been treated using a drive process.

[0089] In some embodiments, heaters are used to heat a first section the formation. For example, heaters may be used to heat a first section of formation to pyrolysis temperatures
25 to produce formation fluids. In some embodiments, heaters are used to heat a first section of the formation to temperatures below pyrolysis temperatures to visbreak and/or mobilize fluids in the formation. In other embodiments, a first section of a formation is heated by heaters prior to, during, or after a drive process is used to produce formation fluids.

[0090] Residual heat from first section may transfer to portions of the formation above,
30 below, and/or adjacent to the first section. The transferred residual heat, however, may not be sufficient to mobilize the fluids in the other portions of the formation towards production wells so that recovery of the fluids from the colder sections fluids may be difficult. Addition of a fluid (for example, a solvation fluid and/or a pressurizing fluid) may solubilize and/or drive the hydrocarbons in the sections of the formation heated by
35 residual heat towards production wells. Addition of a solvating and/or pressurizing fluid to portions of the formation heated by residual heat may facilitate recovery of hydrocarbons without requiring heaters to heat the additional sections. Addition of the fluid may allow

5 for the recovery of hydrocarbons in previously produced sections and/or for the recovery of viscous hydrocarbons in colder sections of the formation.

[0091] In some embodiments, the formation is treated using the in situ heat treatment process for a significant time after the formation has been treated with a drive process. For example, the in situ heat treatment process is used 1 year, 2 years, 3 years, or longer after a
10 formation has been treated using drive processes. After heating for a significant amount of time, a solvation fluid may be added to the heated section and/or portions above and/or below the heated section. The in situ heat treatment process followed by addition of a solvation fluid and/or a pressurizing fluid may be used on formations that have been left dormant after the drive process treatment because further hydrocarbon production using the
15 drive process is not possible and/or not economically feasible. In some embodiments, the solvation fluid and/or the pressurizing fluid is used to increase the amount of heat provided to the formation. In some embodiments, an in situ heat treatment process may be used following addition of the solvation fluid and/or pressurizing fluid to increase the recovery of hydrocarbons from the formation.

20 [0092] In some embodiments, the solvation fluid forms an in situ solvation fluid mixture. Using the in situ solvation fluid may upgrade the hydrocarbons in the formation. The in situ solvation fluid may enhance solubilization of hydrocarbons and/or and facilitate moving the hydrocarbons from one portion of the formation to another portion of the formation.

25 [0093] FIGS. 2 and 3 depict side view representations of embodiments for producing a fluid mixture from the hydrocarbon formation. In FIGS. 2 and 3, heaters 116 have substantially horizontal heating sections below overburden 112 in hydrocarbon layer 114 (as shown, the heaters have heating sections that go into and out of the page). Heaters 116 provide heat to first section 118 of hydrocarbon layer 114. Patterns of heaters, such as
30 triangles, squares, rectangles, hexagons, and/or octagons may be used within first section 118. First section 118 may be heated at least to temperatures sufficient to mobilize some hydrocarbons within the first section. A temperature of the heated first section 118 may range from about 200 °C to about 240 °C. In some embodiments, temperature within first section 118 may be increased to a pyrolyzation temperature (for example between 250 °C
35 and 400 °C).

[0094] In certain embodiments, the bottommost heaters are located between about 2 m and about 10 m from the bottom of hydrocarbon layer 114, between about 4 m and about 8 m

5 from the bottom of the hydrocarbon layer, or between about 5 m and about 7 m from the bottom of the hydrocarbon layer. In certain embodiments, production wells 106A are located at a distance from the bottommost heaters 116 that allows heat from the heaters to superimpose over the production wells, but at a distance from the heaters that inhibits coking at the production wells. Production wells 106A may be located a distance from the
10 nearest heater (for example, the bottommost heater) of at most $\frac{3}{4}$ of the spacing between heaters in the pattern of heaters (for example, the triangular pattern of heaters depicted in FIGS. 2 and 3). In some embodiments, production wells 106A are located a distance from the nearest heater of at most $\frac{2}{3}$, at most $\frac{1}{2}$, or at most $\frac{1}{3}$ of the spacing between heaters in the pattern of heaters. In certain embodiments, production wells 106A are located between
15 about 2 m and about 10 m from the bottommost heaters, between about 4 m and about 8 m from the bottommost heaters, or between about 5 m and about 7 m from the bottommost heaters. Production wells 106A may be located between about 0.5 m and about 8 m from the bottom of hydrocarbon layer 114, between about 1 m and about 5 m from the bottom of the hydrocarbon layer, or between about 2 m and about 4 m from the bottom of the
20 hydrocarbon layer.

[0095] In some embodiments, formation fluid is produced from first section 118. The formation fluid may be produced through production wells 106A. In some embodiments, the formation fluids drain by gravity to a bottom portion of the layer. The drained fluids may be produced from production wells 106A positioned at the bottom portion of the layer.
25 Production of the formation fluids may continue until a majority of condensable hydrocarbons in the formation fluid are produced. After the majority of the condensable hydrocarbons have been produced, first section 118 heat from heaters 116 may be reduced and/or discontinued to allow a reduction in temperature in the first section. In some embodiments, after the majority of the condensable hydrocarbons have been produced, a
30 pressure of first section 118 may be reduced to a selected pressure after the first section reaches the selected temperature. Selected pressures may range between about 100 kPa and about 1000 kPa, between 200 kPa and 800 kPa, or below a fracture pressure of the formation.

[0096] In some embodiments, the formation fluid produced from production wells 106
35 includes at least some pyrolyzed hydrocarbons. Some hydrocarbons may be pyrolyzed in portions of first section 118 that are at higher temperatures than a remainder of the first section. For example, portions of formation adjacent to heaters 116 may be at somewhat

5 higher temperatures than the remainder of first section 118. The higher temperature of the formation adjacent to heaters 116 may be sufficient to cause pyrolysis of hydrocarbons. Some of the pyrolysis product may be produced through production wells 106.

[0097] One or more sections (for example, second section 120 and/or third section 122) may be above and/or below first section 118 (as depicted in FIG. 2). FIG. 3 depicts second
10 section 120 and/or third section 122 adjacent to first section 118. In some embodiments, second section 120 and third section 122 are outside a perimeter defined by the outermost heaters. Some residual heat from first section 118 may transfer to second section 120 and third section 122. In some embodiments, sufficient residual heat is
15 transferred to heat formation fluids to a temperature that allows the fluids to move or substantially move in second section 120 and/or third section 122 towards productions wells 106. Utilization of residual heat from first section 118 to heat hydrocarbons in second section 120 and/or third section 122 may allow the hydrocarbons to be produced from the second section and/or third section without direct heating of the sections. A minimal amount of residual heat to second section 120 and/or third section 122 may be
20 superposition heat from heaters 116. Areas of second section 120 and/or third section 122 that are at a distance greater than the spacing between heaters 116 may be heated by residual heat from first section 118. Second section 120 and/or third section 122 may be heated by conductive and/or convective heat from first section 118. A temperature of the sections heated by residual heat may range from 100 °C to 250 °C, from 150 °C to 225 °C,
25 or from 175 °C to 200 °C depending on the proximity of heaters 116 to second section 120 and/or third section 122.

[0098] In some embodiments, a solvation fluid is provided to first section 118 through injection wells 124A to solvate hydrocarbons within the first section. In some
30 embodiments, solvation fluid is added to first section 118 after a majority of the condensable hydrocarbons have been produced and the first section has cooled. The solvation fluid may solvate and/or dilute the hydrocarbons in first section 118 to form a mixture of condensable hydrocarbons and solvation fluids. Formation of the mixture may increase production of hydrocarbons remaining in the first section. Solubilization of hydrocarbons in first section 118 may allow the hydrocarbons to be produced from the first
35 section after heat has been removed from the section. The mixture may be produced through production wells 106A.

5 [0099] In some embodiments, a solvation fluid is provided to second section 120 and/or third section 122 through injection wells 124B, 124C to increase mobilization of hydrocarbons within the second section and/or the third section. The solvation fluid may increase a flow of mobilized hydrocarbons into first section 118. For example, a pressure gradient may be produced between second section 120 and/or 122 and first section 118
10 such that the flow of fluids from the second section and/or third section to the first section is increased. The solvation fluid may solubilize a portion of the hydrocarbons in second section 120 and/or third section 122 to form a mixture. Solubilization of hydrocarbons in second section 120 and/or third section 122 may allow the hydrocarbons to be produced from the second section and/or third section without direct heating of the sections. In some
15 embodiments, second section 120 and/or third section 122 have been heated from residual heat transferred from first section 118 prior to addition of the solvation fluid. In some embodiments, the solvation fluid is added after second section 120 and/or third section 122 have been heated to a desired temperature by heat from first section 118. In some embodiments, heat from first section 118 and/or heat from the solvation fluid heats section
20 120 and/or third section 122 to temperatures sufficient to mobilize heavy hydrocarbons in the sections. In some embodiments, section 120 and/or third section 122 are heated to temperatures ranging from 50 °C to 250 °C. In some embodiments, temperatures in section 120 and/or third section 122 are sufficient to mobilize heavy hydrocarbons, thus the solvation fluid may mobilize the heavy hydrocarbons by displacing the heavy
25 hydrocarbons with minimal mixing.

[0100] In some embodiments, water and/or emulsified water may be used as a solvation fluid. Water may be injected into a portion of first section 118, second section 120 and/or third section 122 through injection wells 124. Addition of water to at least a selected section of first section 118, second section 120 and/or third section 122 may water saturate
30 a portion of the sections. The water saturated portions of the selected section may be pressurized by known methods and a water/hydrocarbon mixture may be collected using one or more production wells 106.

[0101] In certain embodiments, first section 118, second section 120 and/or third section 122 may be treated with hydrocarbons (for example, naphtha, kerosene, diesel, vacuum gas oil, or a mixture thereof). In some embodiments, the hydrocarbons have an aromatic
35 content of at least 1% by weight, at least 5% by weight, at least 10% by weight, at least 20% by weight or at least 25% by weight. Hydrocarbons may be injected into a portion of

5 first section 118, second section 120 and/or third section 122 through injection wells 124. In some embodiments, the hydrocarbons are produced from first section 118 and/or other portions of the formation. In certain embodiments, the hydrocarbons are produced from the formation, treated to remove heavy fractions of hydrocarbons (for example, asphaltenes, hydrocarbons having a boiling point of at least 300 °C, of at least 400 °C, at
10 least 500 °C, or at least 600 °C) and the hydrocarbons are re-introduced into the formation. In some embodiments, one section may be treated with hydrocarbons while another section is treated with water. In some embodiments, water treatment of a section may be alternated with hydrocarbon treatment of the section. In some embodiments, a first portion of hydrocarbons having a relatively high boiling range distribution (for example, kerosene
15 and/or diesel) are introduced in one section. A second portion of hydrocarbons having a relatively low boiling range distribution or hydrocarbons of low economic value (for example, propane) may be introduced into the section after the first portion of hydrocarbons. The introduction of hydrocarbons of different boiling range distributions may enhance recovery of the higher boiling hydrocarbons and more economically valuable
20 hydrocarbons through production wells 106.

[0102] In an embodiment, a blend made from hydrocarbon mixtures produced from first section 118 is used as a solvation fluid. The blend may include about 20% by weight light hydrocarbons (or blending agent) or greater (for example, about 50% by weight or about 80% by weight light hydrocarbons) and about 80% by weight heavy hydrocarbons or less
25 (for example, about 50% by weight or about 20% by weight heavy hydrocarbons). The weight percentage of light hydrocarbons and heavy hydrocarbons may vary depending on, for example, a weight distribution (or API gravity) of light and heavy hydrocarbons, an aromatic content of the hydrocarbons, a relative stability of the blend, or a desired API gravity of the blend. For example, the weight percentage of light hydrocarbons in the
30 blend may at most 50% by weight or at most 20% by weight. In certain embodiments, the weight percentage of light hydrocarbons may be selected to mix the least amount of light hydrocarbons with heavy hydrocarbons that produces a blend with a desired density or viscosity.

[0103] In some embodiments, polymers and/or monomers may be used as solvation fluids.
35 Polymers and/or monomers may solvate and/or drive hydrocarbons to allow mobilization of the hydrocarbons towards one or more production wells. The polymer and/or monomer may reduce the mobility of a water phase in pores of the hydrocarbon containing

5 formation. The reduction of water mobility may allow the hydrocarbons to be more easily mobilized through the hydrocarbon containing formation. Polymers that may be used include, but are not limited to, polyacrylamides, partially hydrolyzed polyacrylamide, polyacrylates, ethylenic copolymers, biopolymers, carboxymethylcellulose, polyvinyl alcohol, polystyrene sulfonates, polyvinylpyrrolidone, AMPS (2-acrylamide-2-methyl
10 propane sulfonate), or combinations thereof. Examples of ethylenic copolymers include copolymers of acrylic acid and acrylamide, acrylic acid and lauryl acrylate, lauryl acrylate and acrylamide. Examples of biopolymers include xanthan gum and guar gum. In some embodiments, polymers may be crosslinked in situ in the hydrocarbon containing formation. In other embodiments, polymers may be generated in situ in the hydrocarbon
15 containing formation. Polymers and polymer preparations for use in oil recovery are described in U.S. Patent Nos. 6,427,268 to Zhang et al.; 6,439,308 to Wang; 5,654,261 to Smith; 5,284,206 to Surles et al.; 5,199,490 to Surles et al.; and 5,103,909 to Morgenthaler et al.

[0104] In some embodiments, the solvation fluid includes one or more nonionic additives
20 (for example, alcohols, ethoxylated alcohols, nonionic surfactants and/or sugar based esters). In some embodiments, the solvation fluid includes one or more anionic surfactants (for example, sulfates, sulfonates, ethoxylated sulfates, and/or phosphates).

[0105] In some embodiments, the solvation fluid includes carbon disulfide. Hydrogen sulfide, in addition to other sulfur compounds produced from the formation, may be
25 converted to carbon disulfide using known methods. Suitable methods may include oxidizing sulfur compounds to sulfur and/or sulfur dioxide, and reacting sulfur and/or sulfur dioxide with carbon and/or a carbon containing compound to form carbon disulfide. The conversion of the sulfur compounds to carbon disulfide and the use of the carbon disulfide for oil recovery are described in U. S. Patent Publication No. 2006/0254769 to
30 Van Dorp et al. The carbon disulfide may be introduced into first section 118, second section 120 and/or third section 122 as a solvation fluid.

[0106] In some embodiments, the solvation fluid is hydrocarbon compound that is capable of donating a hydrogen atom to the formation fluids. In some embodiments, the solvation fluid is capable of donating hydrogen to at least a portion of the formation fluid thus
35 forming a mixture of solvating fluid and dehydrogenated solvating fluid mixture. The solvating fluid/dehydrogenated solvating fluid mixture may enhance solvation and/or dissolution of a greater portion of the formation fluids as compared to the initial solvation

5 fluid. Examples of such hydrogen donating solvating fluids include, but are not limited to, tetralin, alkyl substituted tetralin, tetrahydroquinoline, alkyl substituted hydroquinoline, 1,2-dihydronaphthalene, a distillate cut having at least 40% by weight naphthenic aromatic compounds, or mixtures thereof. In some embodiments, the hydrogen donating hydrocarbon compound is tetralin.

10 **[0107]** In some embodiments, the first section 118, second section 120 and/or third section 122 are heated to a temperature ranging from 175 °C to 350 °C in the presence of the hydrogen donating solvating fluid. At these temperatures at least a portion of the formation fluids may be hydrogenated by hydrogen donated from the hydrogen donating solvation fluid. In some embodiments, the minerals in the formation act as a catalyst for
15 the hydrogenation process so that elevated formation temperatures may not be necessary. Hydrogenation of at least a portion of the formation fluids may upgrade a portion of the formation fluids and form a mixture of upgraded fluids and formation fluids. The mixture may have a reduced viscosity compared to the initial formation fluids. In situ upgrading and the resulting reduction in viscosity may facilitate mobilization and/or recovery of the
20 formation fluids. In situ upgrading products that may be separated from the formation fluids at the surface include, but are not limited to, naphtha, vacuum gas oil, distillate, kerosene, and/or diesel. Dehydrogenation of at least a portion of the hydrogen donating solvent may form a mixture that has increased polarity as compared to the initial hydrogen donating solvent. The increased polarity may enhance solvation or dissolution of a portion
25 of the formation fluids and facilitate production and/or mobilization of the fluids to production wells 106.

[0108] In some embodiments, the hydrogen donating hydrocarbon compound is heated in a surface facility prior to being introduced into first section 118, second section 120 and/or third section 122. For example, the hydrogen donating hydrocarbon compound may be
30 heated to a temperature ranging from 100 °C to about 180 °C, 120 °C to about 170 °C, or from about 130 to 160 °C. Heat from the hot hydrogen donating hydrocarbon compound may facilitate mobilization, recovery and/or hydrogenation of fluids from first section 118, second section 120 and/or third section 122.

[0109] In some embodiments, a pressurizing fluid is provided in second section 120 and/or
35 third section 122 (for example, through injection wells 124) to increase mobilization of hydrocarbons within the sections. In some embodiments, a pressurizing fluid is provided to second section 120 and/or third section 122 in combination with the solvation fluid to

- 5 increase mobility of hydrocarbons within the formation. The pressurizing fluid may include gases such as carbon dioxide, nitrogen, steam, methane, and/or mixtures thereof. In some embodiments, fluids produced from the formation (for example, combustion gases, heater exhaust gases, or produced formation fluids) may be used as pressurizing fluid.
- 10 [0110] Providing a pressurizing fluid may increase a shear rate applied to hydrocarbon fluids in the formation and decrease the viscosity of non-Newtonian hydrocarbon fluids within the formation. In some embodiments, pressurizing fluid is provided to the selected section before significant heating of the formation. Pressurizing fluid injection may increase a portion of the formation available for production. Pressurizing fluid injection may increase a ratio of energy output of the formation (energy content of products
- 15 produced from the formation) to energy input into the formation (energy costs for treating the formation).
- [0111] Providing the pressurizing fluid may increase a pressure in a selected section of the formation. The pressure in the selected section may be maintained below a selected pressure. For example, the pressure may be maintained below about 150 bars absolute,
- 20 about 100 bars absolute, or about 50 bars absolute. In some embodiments, the pressure may be maintained below about 35 bars absolute. Pressure may be varied depending on a number of factors (for example, desired production rate or an initial viscosity of tar in the formation). Injection of a gas into the formation may result in a viscosity reduction of some of the formation fluids.
- 25 [0112] The pressurizing fluid may enhance the pressure gradient in the formation to flow mobilized hydrocarbons into first section 118. In certain embodiments, the production of fluids from first section 118 allows the pressure in second section 120 and/or third section 122 to remain below a selected pressure (for example, a pressure below which fracturing of the overburden and/or the underburden may occur). In some embodiments, second section
- 30 120 and/or third section 122 have been heated by heat transfer from first section 118 prior to addition of the pressurizing fluid. In some embodiments, the pressurizing fluid is added after second section 120 and/or third section 122 have been heated to a desired temperature by residual heat from first section 118.
- [0113] In some embodiments, pressure is maintained by controlling flow of the
- 35 pressurizing fluid into the selected section. In other embodiments, the pressure is controlled by varying a location or locations for injecting the pressurizing fluid. In other embodiments, pressure is maintained by controlling a pressure and/or production rate at

5 production wells 106. In some embodiments, the pressurized fluid (for example, carbon dioxide) is separated from the produced fluids and re-introduced into the formation. After production has been stopped, the fluid may be sequestered in the formation.

[0114] In certain embodiments, formation fluid is produced from first section 118, second section 120 and/or third section 122. The formation fluid may be produced through
10 production wells 106. The formation fluid produced from second section 120 and/or third section 122 may include solvation fluid; hydrocarbons from first section 118, second section 120 and/or third section 122; and/or mixtures thereof.

[0115] Producing fluid from production wells in first section 118 may lower the average pressure in the formation by forming an expansion volume for fluids heated in adjacent
15 sections of the formation. Thus, producing fluid from production wells 106 in the first section 118 may establish a pressure gradient in the formation that draws mobilized fluid from second section 120 and/or third section 122 into the first section.

[0116] Hydrocarbons may be produced from first section 118, second section 120 and/or third section 122 such that at least about 30%, at least about 40%, at least about 50%, at
20 least about 60% or at least about 70% by volume of the initial mass of hydrocarbons in the formation are produced. In certain embodiments, additional hydrocarbons may be produced from the formation such that at least about 60%, at least about 70%, or at least about 80% by volume of the initial volume of hydrocarbons in the sections is produced from the formation through the addition of solvation fluid.

[0117] Fluids produced from production wells described herein may be transported
25 through conduits (pipelines) between the formation and treatment facilities or refineries. The produced fluids may be transported through a pipeline to another location for further transportation (for example, the fluids can be transported to a facility at a river or a coast through the pipeline where the fluids can be further transported by tanker to a processing
30 plant or refinery). Incorporation of selected solvation fluids and/or other produced fluids (for example, aromatic hydrocarbons) in the produced formation fluid may stabilize the formation fluid during transportation. In some embodiments, the solvation fluid is separated from the formation fluids after transportation to treatment facilities. In some embodiments, at least a portion of the solvation fluid is separated from the formation fluids
35 prior to transportation. In some embodiments, the fluids produced prior to solvent treatment include heavy hydrocarbons.

5 [0118] In some embodiments, the produced fluids may include at least 85% hydrocarbon liquids by volume and at most 15% gases by volume, at least 90% hydrocarbon liquids by volume and at most 10% gases by volume, or at least 95% hydrocarbon liquids by volume and at most 5% gases by volume. In some embodiments, the mixture produced after solvent and/or pressure treatment includes solvation fluids, gases, bitumen, visbroken
 10 fluids, pyrolyzed fluids, or combinations thereof. The mixture may be separated into heavy hydrocarbon liquids, solvation fluid and/or gases. In some embodiments the heavy hydrocarbon liquids, solvation fluid and/or pressuring fluid are re-injected in another section of the formation.

[0119] The heavy hydrocarbon liquids separated from the mixture may have an API
 15 gravity of between 10° and 25°, between 15° and 24°, or between 19° and 23°. In some embodiments, the separated hydrocarbon liquids may have an API gravity between 19° and 25°, between 20° and 24°, or between 21° and 23°. A viscosity of the separated hydrocarbon liquids may be at most 350 cp at 5° C. A P-value of the separated hydrocarbon liquids may be at least 1.1, at least 1.5 or at least 2.0. The separated
 20 hydrocarbon liquids may have bromine of at most 3% and/or CAPP number of at most 2%. In some embodiments, the separated hydrocarbon liquids have an API gravity between 19° and 25°, a viscosity ranging at most 350 cp at 5 °C, a P-value of at least 1.1, a CAPP number of at most 2% as 1-decene equivalent, and/or a bromine number of at most 2%.

[0120] Further modifications and alternative embodiments of various aspects of the
 25 invention may be apparent to those skilled in the art in view of this description.

Accordingly, this description is to be construed as illustrative only and is for the purpose of teaching those skilled in the art the general manner of carrying out the invention. It is to be understood that the forms of the invention shown and described herein are to be taken as the presently preferred embodiments. Elements and materials may be substituted for those
 30 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.

In addition, it is to be understood that

35 features described herein independently may, in certain embodiments, be combined.

CLAIMS:

1. A method of treating a tar sands formation, comprising:

providing heat to a first section of a hydrocarbon layer in the formation from a plurality of heaters located in the first section of the formation;

allowing the heat to transfer from the heaters so that at least the first section of the formation reaches a selected temperature;

allowing at least a portion of residual heat from the heated first section to transfer from the heated first section to a second section of the formation;

heating the unheated portion of the second section to an average temperature of at least 50°C with the residual heat from the first section;

mobilizing at least a portion of hydrocarbons in the second section by providing at least one of a solvation fluid and a pressurizing fluid to the second section of the formation; and

producing a mixture from the second section, wherein the mixture comprises mobilized hydrocarbons and solvation fluid.
2. The method of claim 1, wherein residual heat transfers from the first section to a second section by at least one of conduction and convection.
3. The method of claim 1, wherein superposition of heat from the plurality of heaters heats a majority of the first section.
4. The method of claim 1, wherein a minority of the heat transfers to the unheated portion of the second section through superposition of heat from the plurality of heaters.
5. The method of claim 1, wherein the second section is outside of a perimeter of the heaters.
6. The method of claim 1, wherein a location of a heated area in the second section is greater than an average distance between the heaters in the first section.

7. The method of claim 1, wherein the second section is substantially horizontal to the first section.
8. The method of claim 1, wherein the second section is substantially vertical to the first section.
9. The method of any one of claims 1 to 8, further comprising providing the solvation fluid and/or pressurizing fluid to a third section to mobilize at least a portion of the fluids from the third section of the formation.
10. The method of any one of claims 1 to 8, further comprising providing the solvation fluid and/or pressurizing fluid to a third section to mobilize at least a portion of the fluids from the third section of the formation.
11. The method of claim 1, wherein the selected temperature is between 250 °C and 400 °C or between 200 °C and 240 °C.
12. The method of claim 1, wherein the solvation fluid comprises carbon disulfide, water, hydrocarbons, surfactants, polymers, caustic, alkaline water solutions, sodium carbonate solutions, or mixtures thereof.
13. The method of claim 1, wherein the pressurizing fluid comprises carbon dioxide and/or methane.
14. The method of any one of claims 1 to 13, further comprising producing the mobilized hydrocarbons, and wherein the produced hydrocarbons comprise bitumen.
15. The method of claim 1, wherein the transferred residual heat from the first section heats a portion of the second section to an average temperature between about 50 °C and about 250 °C
16. The method of claim 1, wherein the solvation fluid comprises hydrocarbons, and wherein the hydrocarbons have an aromatic content of at least 1% by weight.

17. A method of treating a hydrocarbon containing formation, comprising:
- providing heat to a first section of a hydrocarbon layer in the formation from a plurality of heaters located in the first section of the formation;
 - allowing the heat to transfer from the heaters so that at least the first section of the formation reaches a selected temperature;
 - allowing at least a portion of residual heat from the heated first section to transfer from the heated first section to an unheated portion of a second section of the formation;
 - heating the unheated portion of the second section to an average temperature of at least 50°C with the residual heat from the first section;
 - mobilizing at least a portion of hydrocarbons in the heated second section by providing a solvation fluid to the second section of the formation; and
 - producing hydrocarbons from the first section, wherein the produced hydrocarbons comprise hydrocarbons from the second section and solvation fluid.
18. The method of claim 17, wherein the produced hydrocarbons further comprise bitumen.
19. The method of claim 17, wherein the solvation fluid comprises hydrocarbons, and wherein the hydrocarbons have an aromatic content of at least 1% by weight.

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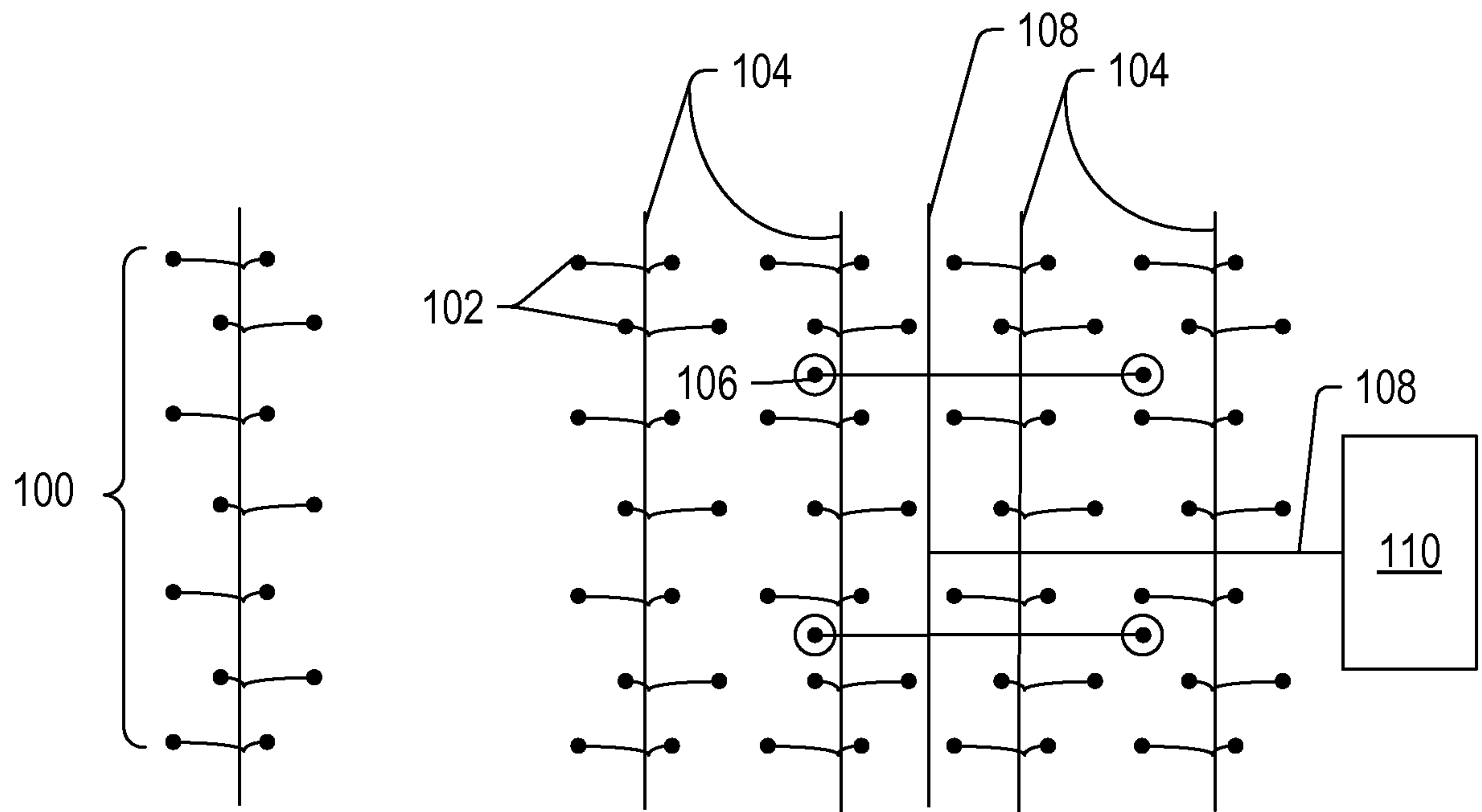


FIG. 1

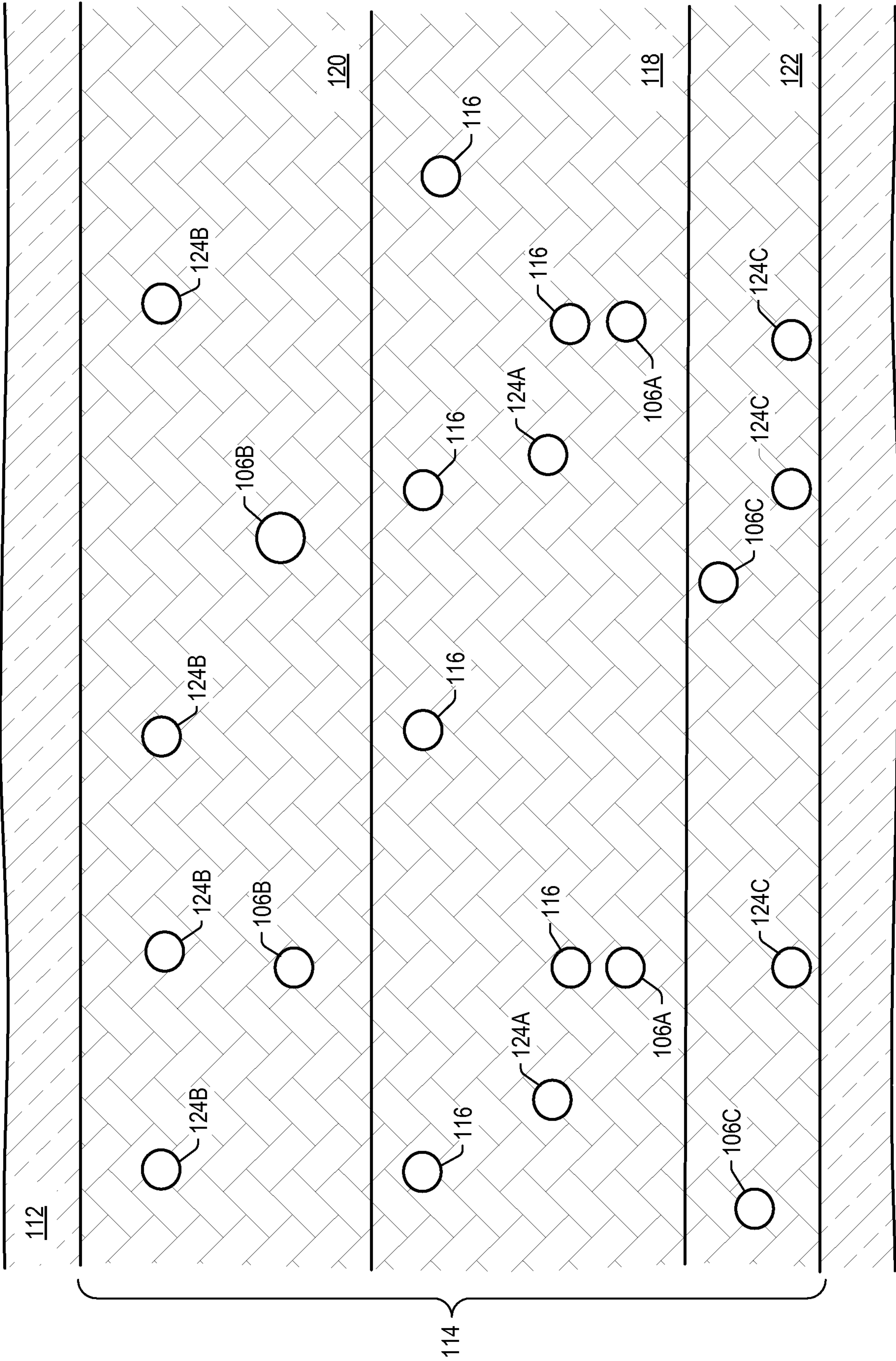


FIG. 2

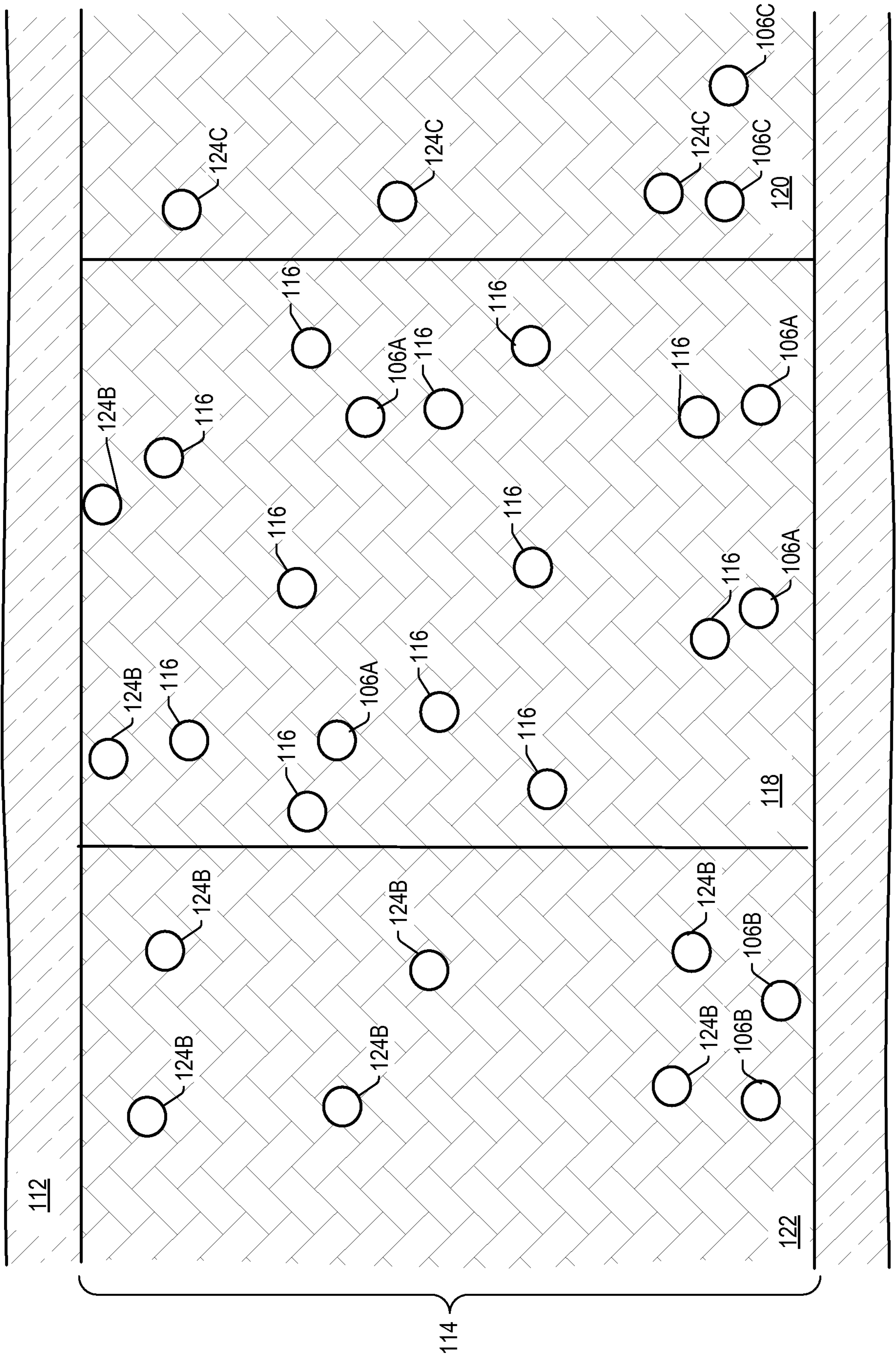


FIG. 3

112



124B



124B



124B



124B



106B



106B

120



116



116



116



116



124A



116



106A



124A



116



106A

118



106C



124C



106C



124C



124C

122

114