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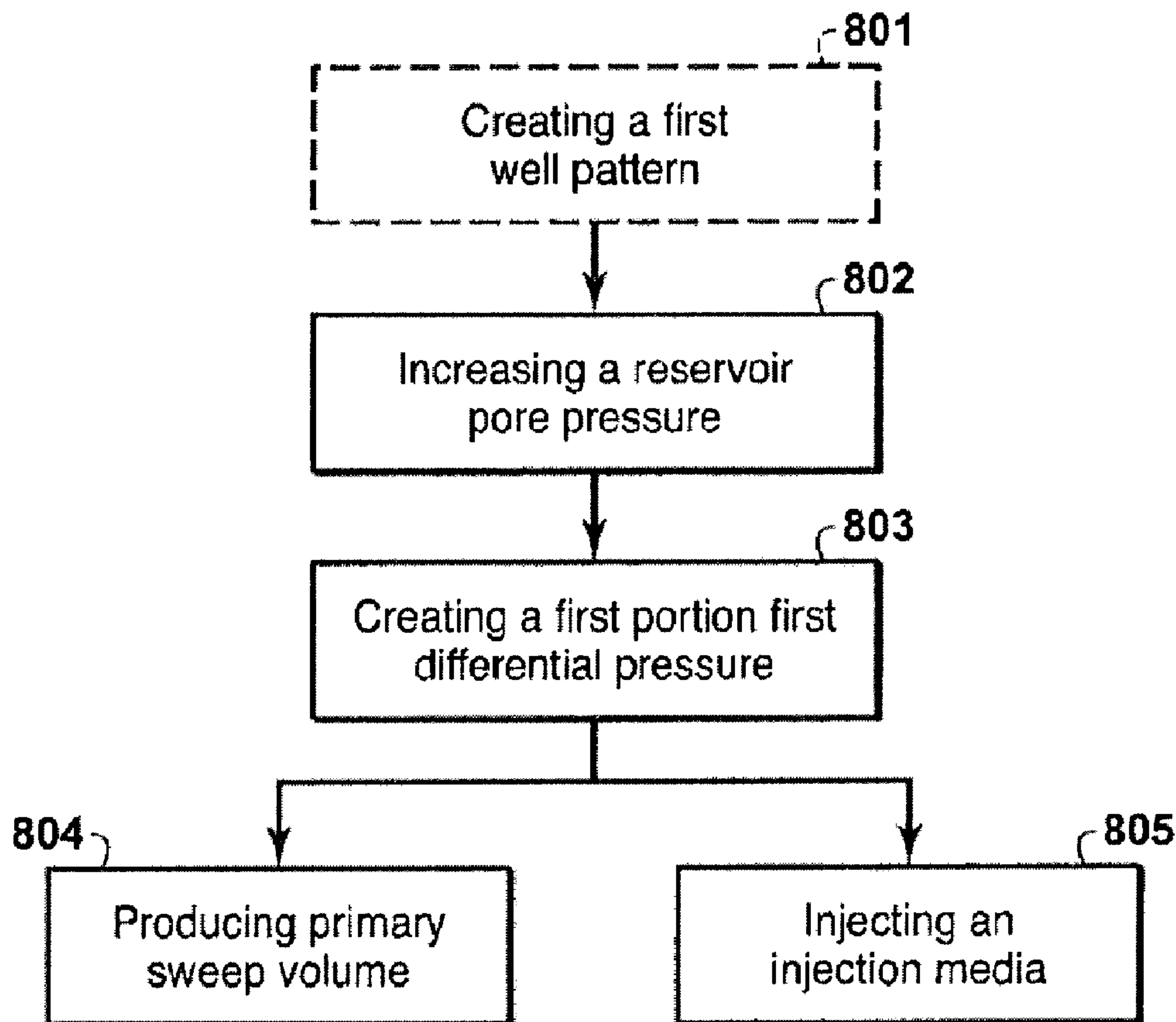
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(54) **Titre :** METHODE ET DISPOSITIF PERMETTANT D'AMELIORER LA RECUPERATION DE PETROLE LOURD D'UN RESERVOIR

(54) **Title:** METHOD AND SYSTEM FOR ENHANCING THE RECOVERY OF HEAVY OIL FROM A RESERVOIR



(57) **Abrégé/Abstract:**

The present disclosure provides a method for enhancing recovery of heavy oil from a reservoir. The method may include increasing a reservoir pore pressure of the reservoir, then; creating a first portion first differential pressure between at least one first portion

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(57) **Abrégé(suite)/Abstract(continued):**

injection well and at least one first portion production well, then; producing primary sweep volume from the first portion first well pattern via one or more of the at least one first portion production well; and injecting an injection media into the subsurface formation until the injection media is produced by the one or more of the at least one first portion production well.

ABSTRACT

The present disclosure provides a method for enhancing recovery of heavy oil from a reservoir. The method may include increasing a reservoir pore pressure of the reservoir, then; creating a first portion first differential pressure between at least one first portion injection well and at least one first portion production well, then; producing primary sweep volume from the first portion first well pattern via one or more of the at least one first portion production well; and injecting an injection media into the subsurface formation until the injection media is produced by the one or more of the at least one first portion production well.

METHOD AND SYSTEM FOR ENHANCING THE RECOVERY OF HEAVY OIL FROM A RESERVOIR

[0001]

BACKGROUND

Fields of Disclosure

[0002] The disclosure relates generally to the field of recovering heavy oil and, more particularly, to a method and system for enhancing the recovery of heavy oil from a reservoir within a subsurface formation.

Description of Related Art

[0003] This section is intended to introduce various aspects of the art, which may be associated with the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

[0004] Modern society is greatly dependent on the use of hydrocarbon resources for fuels and chemical feedstocks. Hydrocarbons are generally found in subsurface formations that can be termed “reservoirs.” Removing hydrocarbons from the reservoirs depends on numerous physical properties of the subsurface formations, such as the permeability of the rock containing the hydrocarbons, the ability of the hydrocarbons to flow through the subsurface formations, and the proportion of hydrocarbons present, among other things. Easily harvested sources of hydrocarbons are dwindling, leaving less accessible sources to satisfy future energy needs. As the costs of hydrocarbons increase, the less accessible sources become more economically attractive.

[0005] Recently, the harvesting of oil sands to remove heavy oil has become more economical. Hydrocarbon removal from oil sands may be performed by several techniques. For example, a well can be drilled to an oil sand reservoir and steam, hot air, solvents, or a combination thereof, can be injected to release the hydrocarbons. The released hydrocarbons may be collected by wells and brought to the surface. In another technique, strip or surface mining may be performed to access the oil sands, which can be treated with hot water, steam or solvents to extract the heavy oil. Strip or surface mining when combined with the hot water or steam may produce a substantial amount of waste or tailings requiring disposal.

[0006] Another process for harvesting oil sands, which may generate less surface waste than other processes, is the slurrified reservoir hydrocarbon recovery process. The slurrified reservoir hydrocarbon recovery process may also be referred to as a slurrified hydrocarbon extraction process.

[0007] In a slurrified reservoir hydrocarbon recovery process, such as that described in U.S. Patent No. 5,823,631, hydrocarbons trapped in solid media, such as bitumen in oil sands, may be recovered from subsurface formations by relieving an overburden stress by injection of water to raise the pore pressure and causing the subsurface formation to flow from an injection well to a production well, for example, by fluid injection, recovering an oil sand/water mixture from the production well, separating the bitumen and reinjecting the remaining sand in a water slurry.

[0008] Another slurrified reservoir hydrocarbon recovery process, such as that described in U.S. Patent No. 8,360,157, may include a method for recovering heavy oil that comprises accessing, from two or more locations, a subsurface formation having an overburden stress disposed thereon. The subsurface formation comprises heavy oil and one or more solids. The subsurface formation is pressurized to a pressure sufficient to relieve the overburden stress. A differential pressure is created between the two or more locations to provide one or more high pressure locations and one or more low pressure locations. The differential pressure is varied within the subsurface formation between the one or more low pressure locations to mobilize at least a portion of the solids and a portion of heavy oil in the subsurface formation. The mobilized solids and heavy oil then flow toward one or more low pressure locations to provide a slurry comprising heavy oil and one or more solids. The slurry comprising the heavy oil and the

one or more solids is flowed to the surface where the heavy oil is recovered from the one or more solids. The one or more solids are recycled to the subsurface formation.

[0009] A process that relates to a slurrified reservoir hydrocarbon recovery process may include methods and systems for recompacting a hydrocarbon reservoir to prevent override of a fill material, such as that described in U.S. Published Application No. 2012/0325461. An exemplary method may include detecting a slurry override condition and reducing a pressure within the reservoir so as to reapply overburden stress.

[0010] The slurrified reservoir hydrocarbon recovery processes discussed above convert the reservoir into a formation resembling a moving bed. When the reservoir moves toward a production well(s), void space is filled by a reinjected stream.

[0011] Although the slurrified reservoir hydrocarbon recovery processes can recover a substantial portion of the heavy oil present in a reservoir, the amount of heavy oil produced from the reservoir may be enhanced by increasing the flow rate in a given portion of the reservoir. But, the flow rate in the reservoir may be limited by achievable flow rates in the production wells. Problems may include but are not limited to ruptures in a well, a well reaching an erosion limit, and a well reaching a mechanical failure. The problems may make it more difficult to achieve optimal production because the problems may occur before achieving optimal production. Heterogeneities or differences in reservoir properties may lead to non-uniform displacement between injection wells and production wells if an entire well pattern is run simultaneously.

[0012] A need exists for improved technology. For example, a need exists for enhancing the recovery of heavy oil from a reservoir within a subsurface formation by, for example, not injecting components at such a fast rate that problems occur within a system before achieving optimal production and/or by increasing the rate of injection within a portion of the reservoir relative to the production rate in a production well by reducing the number of injection wells injecting into a portion of the reservoir associated with that production well. By reducing the number of injection wells associated with a production well or reducing the number of production wells associated with an injection well well, the overall displacement may between injection well(s) and production well(s) may be more uniform.

SUMMARY

[0013] The present disclosure provides a method and system for enhancing the recovery of heavy oil.

[0014] A method for enhancing recovery of heavy oil from a reservoir within a subsurface formation may comprise (a) increasing a reservoir pore pressure of the reservoir, wherein the reservoir includes a first well pattern having at least one injection well and at least one production well and wherein the first well pattern has at least one first portion injection well of the at least one injection well and at least one first portion production well of the at least one production well and wherein the first well pattern has a second portion first well pattern having at least one second portion injection well of the at least one injection well and at least one second portion production well of the at least one production well, then (b) creating a first portion first differential pressure between the at least one first portion injection well and the at least one first portion production well, then; (c) producing primary sweep volume from the first portion first well pattern via one or more of the at least one first portion production well; and (d) injecting an injection media into the subsurface formation until the injection media is produced by the one or more of the at least one first portion production well.

[0015] A method for enhancing recovery of heavy oil from a reservoir within a subsurface formation may comprise (a) creating a first well pattern within a subsurface formation, the first well pattern having at least one injection well and at least one production well, wherein the first well pattern has a first portion first well pattern having at least one first portion injection well of the at least one injection well and at least one first portion production well of the at least one production well and wherein the first well pattern has a second portion first well pattern having at least one second portion injection well of the at least one injection well and at least one second portion production well of the at least one production well; (b) increasing a reservoir pore pressure of the reservoir, then; (c) creating a first portion first differential pressure between the at least one first portion injection well and the at least one first portion production well, then; (d) producing primary sweep volume from the first portion first well pattern via one or more of the at least one first portion production well; and (e) injecting an injection media into the subsurface formation until the injection media is produced by the one or more of the at least one first portion production well.

[0016] The foregoing has broadly outlined the features of the present disclosure so that the detailed description that follows may be better understood. Additional features will also be described.

BRIEF DESCRIPTION OF THE DRAWINGS

[0017] These and other features, aspects and advantages of the present disclosure will become apparent from the following description and the accompanying drawings, which are described briefly below.

[0018] Figure 1 is a diagram showing the use of a slurrified reservoir hydrocarbon recovery process to recover hydrocarbons from a reservoir within a subsurface formation.

[0019] Figure 2a is a diagram of the use of a slurrified reservoir hydrocarbon process to recover hydrocarbons from a reservoir within a first portion first well pattern.

[0020] Figure 2b is a diagram of the use of a slurrified reservoir hydrocarbon recovery process to recover hydrocarbons from a reservoir within a second portion first well pattern.

[0021] Figure 2c is a diagram of the use of a slurrified reservoir hydrocarbon recovery process to recover hydrocarbons from a reservoir within a first portion first well pattern and a second portion first well pattern.

[0022] Figure 3a is a diagram showing the use of a slurrified reservoir hydrocarbon recovery process to recover hydrocarbons from a reservoir within a first portion first well pattern.

[0023] Figure 3b is a diagram showing the use of a slurrified reservoir hydrocarbon recovery process to recover hydrocarbons from a reservoir within a second portion first well pattern.

[0024] Figure 3c is a diagram showing the use of a slurrified reservoir hydrocarbon recovery process to recover hydrocarbons from a reservoir within a first portion first well pattern and a second portion first well pattern.

[0025] Figure 4 is a diagram of the use of a slurrified reservoir hydrocarbon process after a recompletion process.

[0026] Figure 5 is a diagram of the use of a slurrified reservoir hydrocarbon recovery process after the recompletion process.

[0027] Figure 6 is a diagram showing a method of a slurrified reservoir hydrocarbon recovery process.

[0028] It should be noted that the figures are merely examples and that no limitations on the scope of the present disclosure are intended hereby. Further, the figures are generally not drawn

to scale but are drafted for the purpose of convenience and clarity in illustrating various aspects of the disclosure.

DETAILED DESCRIPTION

[0029] For the purpose of promoting an understanding of the principles of the disclosure, reference will now be made to the features illustrated in the drawings and specific language will be used to describe the same. It will nevertheless be understood that no limitation of the scope of the disclosure is thereby intended. Any alterations and further modifications, and any further applications of the principles of the disclosure as described herein are contemplated as would normally occur to one skilled in the art to which the disclosure relates. It will be apparent to those skilled in the relevant art that some features that are not relevant to the present disclosure may not be shown in the drawings for the sake of clarity.

[0030] At the outset, for ease of reference, certain terms used in this application and their meaning as used in this context are set forth below. To the extent a term used herein is not defined below, it should be given the broadest definition persons in the pertinent art have given that term as reflected in at least one printed publication or issued patent. Further, the present processes are not limited by the usage of the terms shown below, as all equivalents, synonyms, new developments and terms or processes that serve the same or a similar purpose are considered to be within the scope of the present disclosure.

[0031] “Bitumen” is a naturally occurring heavy oil material. Generally, it is the hydrocarbon component found in oil sands. Bitumen can vary in composition depending upon the degree of loss of more volatile components. It can vary from a very viscous, tar-like, semi-solid material to solid forms. The hydrocarbon types found in bitumen can include aliphatics, aromatics, resins, and asphaltenes. A typical bitumen might be composed of:

19 weight (wt.) % aliphatics (which can range from 5 wt. % - 30 wt. %, or higher);

19 wt. % asphaltenes (which can range from 5 wt. % - 30 wt. %, or higher);

30 wt. % aromatics (which can range from 15 wt. % - 50 wt. %, or higher);

32 wt. % resins (which can range from 15 wt. % - 50 wt. %, or higher); and

some amount of sulfur (which can range in excess of 7 wt. %).

In addition bitumen can contain some water and nitrogen compounds ranging from less than 0.4 wt. % to in excess of 0.7 wt. %. The percentage of the hydrocarbon found in bitumen can vary. The term “heavy oil” includes bitumen as well as lighter materials that may be found in a sand or carbonate reservoir.

[0032] “Breakthrough” refers to a description of reservoir conditions under which an injection material, previously isolated or separated from production as observed at the production well(s), gains access to one or more production wells. For breakthrough to occur, anywhere from greater than 0 to less than or equal to 100 percent of the material being produced at the production well(s) is injection media. The percentage of injection material may include any number within or bounded by the preceding material. For example, the percentage of injection material may be, but is not limited to, at least 50% or no more than 90%. In other words, breakthrough refers to a description of reservoir conditions when a material injected into the reservoir reaches one or more production wells after being reinjected into the reservoir. Breakthrough may occur at the end of primary production. Breakthrough may occur at the end of secondary production. When breakthrough occurs at the end of secondary production, the percentage of media being produced at the production well(s) is reinjection media and/or injection media. Breakthrough may occur at the end of any production (e.g., primary production, secondary production, tertiary production).

[0033] “Conditioning fluid” is fluid injected into a reservoir prior to primary production to increase the pore pressure of the reservoir. The conditioning fluid may be any suitable fluid. For example, the conditioning fluid may comprise at least one of water, fines, caustic, flocculants, coagulants, sodium silicate, polymeric compounds, salts, solvents, brine, hydrocarbons, polymers, and hydrocarbons.

[0034] “Facility” is a tangible piece of physical equipment through which hydrocarbon fluids are either produced from a reservoir or injected into a reservoir, or equipment which can be used to control production or completion operations. In its broadest sense, the term facility is applied to any equipment that may be present along the flow path between a reservoir and its delivery outlets. Facilities may comprise production wells, injection wells, well tubulars, wellhead equipment, gathering lines, manifolds, pumps, compressors, separators, surface flow lines, sand

processing plants, and delivery outlets. In some instances, the term “surface facility” is used to distinguish from those facilities other than wells.

[0035] “Heavy oil” includes oils which are classified by the American Petroleum Institute (“API”), as heavy oils, extra heavy oils, or bitumens. The term “heavy oil” includes bitumen. Heavy oil may have a viscosity of about 1,000 centipoise (cP) or more, 10,000 cP or more, 100,000 cP or more, or 1,000,000 cP or more. In general, a heavy oil has an API gravity between 22.3° API (density of 920 kilograms per meter cubed (kg/m^3) or 0.920 grams per centimeter cubed (g/cm^3)) and 10.0° API (density of 1,000 kg/m^3 or 1 g/cm^3). An extra heavy oil, in general, has an API gravity of less than 10.0° API (density greater than 1,000 kg/m^3 or 1 g/cm^3). For example, a source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, silt, sand, water and bitumen.

[0036] A “hydrocarbon” is an organic compound that primarily includes the elements of hydrogen and carbon, although nitrogen, sulfur, oxygen, metals, or any number of other elements may be present in small amounts. Hydrocarbons generally refer to components found in heavy oil or in oil sands. Hydrocarbon compounds may be aliphatic or aromatic, and may be straight chained, branched, or partially or fully cyclic.

[0037] “Injection media” is media injected into the reservoir during primary production. The injection media may comprise, for example, at least one of water, clay, silt, sand, brine, salts, hydrocarbons, polymers, coagulants, flocculants, solvents and conditioning fluid. The injection media may comprise a portion of the conditioning fluid. The injection media may include reinjected sand.

[0038] An “injection well” refers to a well or wellbore that receives a material, such as but not limited to the conditioning fluid or the injection media.

[0039] A “line drive well pattern” refers to an injection pattern in which injection wells are located in a first straight line and production wells are located in a second straight line that is parallel to the first straight line.

[0040] “Overburden” refers to the material overlying a reservoir. The overburden may contain rock, soil, sand, clay, pore fluids, and ecosystem above the reservoir. The pore fluids may include, but are not limited to, water and/or hydrocarbons.

[0041] “Overburden stress” is the stress, or force exerted by unit area, that the overburden applies to the sands within the reservoir due to its weight. Overburden stress may be considered to be the effective stress applied by the overburden, e.g., the total stress of the overburden minus the fluid pressure within the reservoir. As such, overburden stress is a measure of the vertical component of the stress the solids in the reservoir exert on each other due to the weight of the overburden. “Overburden stress” may interchangeably be referred to as “overburden load.” The solids in the reservoir may comprise sand grain, silt and/or clay particles, etc.

[0042] “Permeability” is the capacity of a rock to transmit fluids through the interconnected pore spaces of the structure. The customary unit of measurement for permeability is the milliDarcy (mD). The term “relatively permeable” is defined, with respect to formations or portions thereof (for example, 10 or 100 mD). The term “relatively low permeability” is defined, with respect to subsurface formations or portions thereof, as an average permeability of less than about 10 mD.

[0043] “Pressure” is a force exerted per unit area which is defined as being equal in all directions and is typically used here in reference to the pore fluids in the reservoir or to describe, in part, the fluid or material in the injection wells and production wells. Pressure can be shown as pounds per square inch (psi), kilopascals (kPa), or megapascals (MPa). “Atmospheric pressure” refers to the local pressure of the air. “Absolute pressure” (psia) refers to the sum of the atmospheric pressure (14.7 psia at standard conditions) plus the gauge pressure. “Gauge pressure” (psig) refers to the pressure measured by a gauge, which indicates only the pressure exceeding the local atmospheric pressure (i.e., a gauge pressure of 0 psig corresponds to an absolute pressure of 14.7 psia). The term “vapor pressure” has the usual thermodynamic meaning. For a pure component in an enclosed system at a given pressure, the component vapor pressure is essentially equal to the total pressure in the system.

[0044] “Pressure gradient” represents the pressure differences divided by the distance between the locations where those pressure differences are measured (e.g., the change in pore pressure per unit of depth). Depth may refer to length or width. Pressure gradient is a measure of driving force moving the sand through the subterranean reservoir or the pressure moving slurries through a pipe. The “pressure gradient” may interchangeably be referred to as a “pore pressure gradient” or, when the distance over which the pressure varies, a “differential pressure.”

[0045] “Primary production,” primary recovery or primary sweep is the first stage of hydrocarbon production by which the formation is displaced by an injection media injected at an injection well and produced via a production well. Primary production may terminate at or after breakthrough.

[0046] “Primary sweep volume” is material produced from the reservoir during primary recovery. Primary sweep volume may refer to the volume of the reservoir produced during primary production. For example, primary sweep volume may refer to anywhere between 20 to 70% inclusive volume of a reservoir total volume within a subsurface formation path of the total volume of reservoir produced during primary production within the subsurface formation path. The aforementioned ranges may include any number bounded by and/or within the preceding ranges. The primary sweep volume may comprise at least one of heavy oil, sand, silt, clay, connate or in situ water, and conditioning fluid. The primary sweep volume may comprise a portion of the conditioning fluid.

[0047] “Production well” refers to a well or wellbore that produces a material.

[0048] A “recompleted injection well” is a well that initially served as a production well but has been completed to serve as an injection well. In other words, such a well is a well that initially produced materials, such as but not limited to primary sweep volume and/or secondary sweep volume, and later receives materials, such as but not limited to injection media.

[0049] A “recompleted production well” is a well that initially served as an injection well but has been completed to serve as a production well. In other words, such a well is a well that initially received materials to be injected, such as but not limited to injection media, and later produces materials, such as but not limited to primary sweep volume and/or secondary sweep volume.

[0050] “Reconditioning fluid” is fluid injected into a reservoir prior to secondary production and/or tertiary production, etc. to increase the pore pressure of the reservoir. The reconditioning fluid may be any suitable fluid. For example, the reconditioning fluid may comprise at least one of water, fines, caustic, flocculants, coagulants, sodium silicate, polymeric compounds, salts, solvents, brine, hydrocarbons, polymers, and hydrocarbons. Reconditioning fluid may include conditioning fluid such as, for example, a portion of the conditioning fluid.

[0051] “Reinjected sand” may comprise sand, clay, and silt that was previously within the reservoir, was produced from the reservoir and is now being reinjected into the reservoir. Reinjected sand may comprise any part of the reservoir. For example, the reinjected sand may comprise clay, fluid, etc., in a proportion that may be the same or different than the makeup of clay, fluid, etc. in the reservoir.

[0052] “Reinjection media” is media injected into the reservoir during secondary production and/or tertiary production, etc. The reinjection media may comprise, for example, at least one of water, clay, silt, sand, brine, salts, hydrocarbons, polymers, coagulants, flocculants, solvents, conditioning fluid, reconditioning fluid and injection media. The reinjection media may comprise a portion of the conditioning fluid, reconditioning fluid and/or injection media. The reinjection media may include the reinjected sand.

[0053] A “reservoir” or “subterranean reservoir” is a subsurface rock or sand formation from which a production fluid or resource can be harvested. The subsurface rock or sand formation may include sand, granite, silica, carbonates, clays, and organic matter, such as bitumen, heavy oil (e.g., bitumen), gas, or coal, among others. Reservoirs can vary in thickness from less than one foot (0.3048 meter (m)) to hundreds of feet (hundreds of meters).

[0054] “Reservoir pore pressure” is the pressure of fluids within pores of a reservoir at a given time. “Reservoir pore pressure” may be interchangeably referred to as “pore pressure.”

[0055] A “Sand breakthrough indicator” refers to a way of detecting breakthrough. For example, a sand breakthrough indicator may refer to a way of detecting the end of primary production and/or secondary production at a given production well along a subsurface formation path that material travels from one or more injection wells to the given production well. More specifically, if there is one production well and four injection wells, the sand breakthrough indicator may detect when breakthrough occurs along the subsurface formation path from each of the four injection wells to the production well such that if breakthrough occurs first along the subsurface formation path from a first one of the four injection wells to the production well, the one of the four injection wells can be shut in while material continues to travel from the other of the three injection wells to the production well. This process may continue until breakthrough has occurred for all of the injection wells. The sand breakthrough indicator may comprise any suitable mechanism. For example, the sand breakthrough indicator may comprise periodically

conducting a well test (e.g. once a week), taking a sample (e.g., of the well) every well test to detect the bitumen flow rate, or using a tracer in the injection media to indicate when injected media is produced into the production well. If the sand breakthrough indicator comprises taking the sample, the sand breakthrough indicator may also comprise one or more well tests and using the tracer media in the injection media. If the sand breakthrough indicator comprises one of these additional steps, the sand breakthrough indicator may determine where breakthrough occurs. Merely taking the sample may indicate that breakthrough has occurred but may not indicate where breakthrough has occurred; performing one of these additional steps may determine where the breakthrough has occurred. The bitumen concentration variation at the production well may also be used. The tracer may be radioactive, ferrous, or otherwise labeled.

[0056] “Secondary production,” secondary recovery or secondary sweep is the second stage of hydrocarbon recovery. Secondary production occurs after primary production.

[0057] “Secondary sweep volume” is material produced from the reservoir during secondary recovery. Secondary sweep volume may refer to the volume of the reservoir produced during secondary production. For example, secondary sweep volume may refer to anywhere between 20 to 70% inclusive volume of the reservoir total volume within a subsurface formation path of the total volume of reservoir produced during secondary production within the subsurface formation path. The aforementioned range may include any number bounded by or within the preceding range. The secondary sweep volume may include some of the volume produced during primary production as this volume may be reinjected into the reservoir and produced during secondary production. The secondary sweep volume may comprise at least one of heavy oil, sand, silt, clay, conditioning fluid, reconditioning fluid, and injection media. The secondary sweep volume may comprise a portion of the conditioning fluid. The secondary sweep volume may comprise a portion of the reconditioning fluid. The secondary sweep volume may comprise a portion of the injection media.

[0058] “Shut in” refers to a shut in injection well or a shut in production well. A well that is shut in no longer injects or produces material, but may still be utilized for reservoir monitoring. For example, the well may be used to monitor a pore pressure in a reservoir or for sampling material in the reservoir. “Shutting in” may interchangeably be used to refer to a well that is shut in.

[0059] “Substantial” when used in reference to a quantity or amount of a material, or a specific characteristic thereof, refers to an amount that is sufficient to provide an effect that the material or characteristic was intended to provide. The exact degree of deviation allowable may in some cases depend on the specific context. For example, the exact degree of deviation allowable may range anywhere from less than or equal to a 10% exact degree in deviation.

[0060] A “subsurface formation” refers to the material existing below the Earth’s surface. The subsurface formation may interchangeably be referred to as a formation, subsurface or a subterranean formation. The subsurface formation may comprise a range of components, e.g. minerals such as quartz, siliceous materials such as sand and clays, as well as the oil and/or gas that is extracted.

[0061] A “subsurface formation path” refers to the path within a subsurface formation that portions of the reservoir within the subsurface formation could travel when the portions of the reservoir are, for example but not limited to, produced from the subsurface formation. For example, the subsurface formation path may refer to a path between one or more injection wells and production wells that portions of the reservoir may travel by injecting into the one or more injection well and producing from the one or more production well.

[0062] A “wellbore” is a hole or access path in the subsurface made by drilling or inserting a conduit into the subsurface. A wellbore may have a substantially circular cross section or any other cross-section shape, such as an oval, a square, a rectangle, a triangle, or other regular or irregular shapes. The term “well,” when referring to an opening in the formation, may be used interchangeably with the term “wellbore.” Further, multiple pipes may be inserted into a single wellbore, for example, as a liner configured to allow flow from an outer chamber to an inner chamber.

[0063] “Well pattern” refers to a configuration of wells within a single pattern. Examples of well patterns include, but are not limited to, a line drive well pattern, a 4-spot well pattern, an inverted 4-spot well pattern, a 5-spot well pattern, an inverted 5-spot well pattern, a 7-spot well pattern, an inverted 7-spot well pattern, a 9-spot well pattern and an inverted 9-spot well pattern.

[0064] A “4-spot well pattern” refers to a standard 4-spot well pattern. A standard 4-spot well pattern includes 3 injection wells at corners of a triangle and a production well at the center of the triangle.

[0065] An “inverted 4-spot well pattern” refers to a standard inverted 4-spot well pattern. An inverted 4-spot well pattern includes 3 production wells at corners of a triangle and an injection well at the center of the triangle.

[0066] A “5-spot well pattern” refers to a standard 5-spot well pattern. A standard 5-spot well pattern includes 4 injection wells at corners of a square and a production well at the center of the square.

[0067] An “inverted 5-spot well pattern” refers to a standard inverted 5-spot well pattern. An inverted 5-spot well pattern includes 5 production wells at corners of a square and an injection well at the center of the square.

[0068] A “7-spot well pattern” refers to a standard 7-spot well pattern. A standard 7-spot well pattern includes 6 injection wells at corners of a hexagon and a production well at the center of the hexagon.

[0069] An “inverted 7-spot well pattern” refers to a standard inverted 7-spot well pattern. An inverted 7-spot well pattern includes 6 production wells at corners of a hexagon and an injection well at the center of the hexagon.

[0070] A “9-spot well pattern” refers to a standard 9-spot well pattern. A standard 9-spot well pattern includes 8 injection wells at corners and midpoints of the sides of a square and a production well at the center of the square.

[0071] An “inverted 9-spot well pattern” refers to a standard inverted 9-spot well pattern. An inverted 9-spot well pattern includes 9 production wells at corners and side midpoints of a square and an injection well at the center of the square.

[0072] “At least one,” in reference to a list of one or more entities should be understood to mean at least one entity selected from any one or more of the entity in the list of entities, but not necessarily including at least one of each and every entity specifically listed within the list of entities and not excluding any combinations of entities in the list of entities. This definition also allows that entities may optionally be present other than the entities specifically identified within the list of entities to which the phrase “at least one” refers, whether related or unrelated to those entities specifically identified. Thus, as a non-limiting example, “at least one of A and B” (or, equivalently, “at least one of A or B,” or, equivalently “at least one of A and/or B”) may refer, to

at least one, optionally including more than one, A, with no B present (and optionally including entities other than B); to at least one, optionally including more than one, B, with no A present (and optionally including entities other than A); to at least one, optionally including more than one, A, and at least one, optionally including more than one, B (and optionally including other entities). In other words, the phrases “at least one,” “one or more,” and “and/or” are open-ended expressions that are both conjunctive and disjunctive in operation. For example, each of the expressions “at least one of A, B and C,” “at least one of A, B, or C,” “one or more of A, B, and C,” “one or more of A, B, or C” and “A, B, and/or C” may mean A alone, B alone, C alone, A and B together, A and C together, B and C together, A, B and C together, and optionally any of the above in combination with at least one other entity.

[0073] Where two or more ranges are used, such as but not limited to 1 to 5 or 2 to 4, any number between or inclusive of these ranges is implied.

[0074] The articles “the”, “a” and “an” are not necessarily limited to mean only one, but rather are inclusive and open ended so as to include, optionally, multiple such elements.

[0075] As depicted in Figures 1-6 and set forth above and below, the present disclosure relates to a system and method for recovering heavy oil, and more particularly to a system and method for enhancing the recovery of heavy oil from a reservoir within a subsurface formation. The system and method make it possible to increase production from a reservoir when compared to a system and/or method where an entire well pattern is run simultaneously. The system and method make it possible to run a portion, such as but not limited to a first portion or a second portion, of a well pattern at a time, thereby increasing production from that of a system and/or method where the entire well pattern is run simultaneously. In other words, the system and method make it possible to produce portions of a reservoir that remain after primary production within an entire well pattern or a portion of a well pattern, thereby enhancing the recovery of heavy oil. The system and method may produce portions of a reservoir that remain after primary production within an entire well pattern or a portion of a well pattern by modifying the flow direction by which material is produced from the reservoir, thereby allowing for the production of not previously produced subsurface formation paths within the reservoir. The system and method allow for the modification by modifying the pattern of injection wells and/or production wells. The portion of the well pattern, such as but not limited to the first portion of the well

pattern (i.e., the first portion well pattern) or the second portion of the well pattern (i.e., the second portion well pattern) is some portion that is smaller than the entirety of the well pattern. The system and method may lead to a more uniform recovery as there may be conditions within the reservoir that challenge uniform recovery between injection wells and production wells if an entire well pattern is run simultaneously. Operating a first portion of a well pattern and then a second portion of the well pattern may mitigate against uniform recovery being negatively impacted due to variations in reservoir properties and stress conditions that may lead to nonuniform sweep between injection wells and production wells had the entirety of the well pattern been run simultaneously.

[0076] The system 100 and method may include at least one injection well 104 and at least one production well 106 (Figure 1). The at least one injection well 104 may just be referred to as an injection well for simplicity. The at least one production well 106 may just be referred to as a production well for simplicity. The at least one injection well 104 and the at least one production well 106 may access a reservoir 102 within a subsurface formation 124. The at least one injection well 104 and the at least one production well 106 may extend through an overburden 108 of the subsurface formation 124 to access the reservoir 102. The overburden 108 may be above the reservoir 102. The overburden 108 may be closer to the Earth's surface 112 than the reservoir 102. The reservoir 102 may be at depths greater than or equal to about 50 meters from the Earth's surface 112. The depths may include any number within or inclusive of the preceeding range.

[0077] The at least one injection well 104 may extend through the reservoir 102. The at least one injection well 104 may include one or more injection wells 104. For example, the at least one injection well may include one injection well, two injection wells, three injection wells, etc. The at least one injection well 104 may include any number of injection wells that is greater than or equal to one. The number of injection wells may include any number within and/or inclusive of the preceding range.

[0078] The at least one production well 106 may extend through the reservoir 102. The at least one production well 106 may include one or more production wells 106. For example, the at least one production well may include one production well, two production wells, three injection wells, etc. The at least one production well 106 may include any number of production

wells that is greater than or equal to one. The number of production wells may include any number within and/or inclusive of the preceding range.

[0079] The system and method may include creating a first well pattern 1110, 801 (Figures 2a-3c and 6). The first well pattern 1110 may have the at least one injection well 104 and the at least one production well 106. The first well pattern 1110 may have a first portion first well pattern 1111 (Figures 2a and 3a). The first portion first well pattern 1111 may include at least one first portion injection well 104a of the at least one injection well 104. The first portion first well pattern 1111 may include at least one first portion production well 106a of the at least one production well 106. The first well pattern 1110 may have a second portion first well pattern 1112 (Figures 2b and 3b). The second portion first well pattern 1112 may include at least one second portion injection well 104b of the at least one injection well 104 and at least one second portion production well 106b of the at least one production well 106.

[0080] Figures 2a-3a show multiple first portion first well patterns 1111 where one first portion first well pattern 1111 is inside one first well pattern 1110. Figures 2a-3a show the first portion first subsurface formation path 1300 that hydrocarbons travel within the first portion first well pattern 1111. The first portion first subsurface formation path is depicted by the shaded areas within the first portion first well pattern 1111. Figures 2b-3b show multiple second portion first well patterns 1112 where one second portion first well pattern 1112 is inside one first well pattern 1110. Figures 2b-3b show the second portion first subsurface formation 1301 path that hydrocarbons travel within the second portion first well pattern 1112. The second portion first subsurface formation path is depicted by the shaded areas within the second portion first well pattern 1112. Figures 2c-3c shows multiple first portion first well patterns 1111 and multiple second portion first well patterns 1112 where one first portion first well pattern 1111 and one second portion first well pattern 1112 is inside one first well pattern 1110. Figures 2c-3c show the first portion first subsurface formation path 1300 and the second portion first subsurface path 1301 that hydrocarbons travelled for the first portion first well pattern and the first portion second well pattern, respectively. The first portion first subsurface formation path is depicted by the shaded areas within the first portion first well pattern 1111; the second portion first subsurface formation path is depicted by the shaded areas within the second portion first well pattern 1112.

[0081] The first well pattern 1110 may consist of the first portion first well pattern 1111 and the second portion first well pattern 1112. If the first well pattern 1110 consists of the first portion first well pattern 1111 and the second portion first well pattern 1112, the first well pattern 1110 only contains the first portion first well pattern 1111 and the second portion first well pattern 1112.

[0082] The first well pattern 1110 may comprise the first portion first well pattern 1111 and the second portion first well pattern 1112. If the first well pattern 1110 comprises the first portion first well pattern 1111 and the second portion first well pattern 1112, the first well pattern 1110 may include more than the first portion first well pattern 1111 and the second portion first well pattern 1112. For example but not limited to, the first well pattern 1110 may include the first portion first well pattern 1111, the second portion first well pattern 1112 and a third portion first well pattern 1113.

[0083] The first well pattern may comprise any suitable well pattern that is able to be separated into at least two portions, such as the first portion first well pattern 1111 and the second portion first well pattern 1112. For example, the first well pattern may comprise one of a five-spot well pattern, an inverted five-spot well pattern, a seven-spot well pattern and a nine-spot well pattern.

[0084] While the above section and preceding sections discuss a first well pattern, the system and method may comprise more than one well pattern. For example, the system and method may comprise a first well pattern, a second well pattern, etc. Each of the well patterns may have similar structures and/or operate similarly to the present disclosure's description of the first well pattern.

[0085] The at least one first portion injection well 104a may be the at least one second portion injection well 104b. In other words, the at least one first portion injection well 104a may be the same well and therefore not separate from the at least one second portion injection well 104b. The at least one first portion injection well 104a may be the at least one second portion injection well 104b when the well pattern is inverted. Examples of a well pattern that is inverted include an inverted five-spot well pattern. When the at least one first portion injection well 104a is the at least one second portion injection well 104b, the at least one first portion production well 106a may be separate from the at least one second portion production well 106b. In other

words, the at least one first portion production well 106a may be a different well from the at least one second portion production well 106b.

[0086] The at least one first portion production well 106a may be the at least one second portion production well 106b. In other words, the at least one first portion production well 106a may be the same well and therefore not separate from the at least one second portion production well 106b. Examples of a well pattern that is not inverted include a five-spot well pattern, a seven-spot well pattern and a nine-spot well pattern. When the at least one first portion production well 106a is the at least one second portion production well 106b, the at least one first portion injection well 104a may be separate from the at least one second portion injection well 104b. In other words, the at least one first portion injection well 104a may be a different well from the at least one second portion injection well 104b.

[0087] One or more of the at least one first portion injection well 104a may be separate from one or more of the at least one second portion injection well 104b. In other words, none or only some of the one or more of the at least one first portion injection well 104a may be the same injection well as none or only some of the one or more of the second portion injection well 104b.

[0088] One or more of the at least one first portion production well 106a may be separate from one or more of the at least one second portion production well 106b. In other words, none or only some of the one or more of the at least one first portion production well 106a may be the same injection well as none or only some of the one or more of the second portion production well 106b.

[0089] The system and method may include increasing a reservoir pore pressure of the reservoir 102, 802 (Figure 6). Increasing the reservoir pore pressure may comprise injecting a conditioning fluid into the reservoir 102. The conditioning fluid may be injected at one or more locations within the subsurface formation 124. The conditioning fluid may be injected into any suitable location within the reservoir 102. The pressure caused by the injection of the conditioning fluid may allow the conditioning fluid to permeate through the portion of the reservoir 102 that contains hydrocarbons. As the conditioning fluid is injected, the reservoir pore pressure increases and may thereby alleviate or mostly balance the stresses on the reservoir 102 that are caused by an overburden stress. Accordingly, the pressure of the conditioning fluid injected may be sufficient to alleviate and/or substantially balance overburden stress. The

pressure of the conditioning fluid may be sufficient to develop a substantially constant pressure within the reservoir 102.

[0090] Injecting the conditioning fluid into the reservoir 102 may comprise injecting the conditioning fluid via one or more of the at least one first portion injection well 104a and the at least one first portion production well 106a within the first well pattern 1111. The at least one first portion injection well 104a and the at least one first portion production well 106a may each have a structure that enable them to receive the conditioning fluid. Examples of the structure may include, but are not limited to, an uncased wellbore or a cased wellbore. The conditioning fluid travels in the at least one first portion injection well 104a and the at least one first portion production well 106a in a direction 122 toward the reservoir 102. The conditioning fluid may be fed to the reservoir 102.

[0091] When the conditioning fluid is injected into one or more of the at least one first portion injection well 104a and the at least one first portion production well 106a, the porosity of the subsurface formation 124 may increase. The porosity of the subsurface formation 124 may increase because the reservoir 102 may comprise a sand particle network. The sand particle network may dilate or expand in volume as the effective stress due to the overburden stress is alleviated and/or substantially balanced by the increase in reservoir pore pressure. The increase in porosity may be accompanied by a decrease in the mechanical strength of the material within the reservoir 102 to a state where the material within the reservoir 102 may slide in a direction of the at least one first portion production well 106a when a pressure gradient is imposed due to the flow of a fluid from the at least one first portion injection well 104a to the at least one first portion production well 106a. Increasing the initial porosity of the subsurface formation 124 may increase the permeability of the subsurface formation 124.

[0092] The injection of the conditioning fluid into one or more of the at least one first portion injection well 104a and the at least one first portion production well 106a may be referred to as the conditioning process. In other words, the conditioning fluid may be injected into one or more of the at least one first portion injection well 104a and the at least one first portion production well 106a during the conditioning process. When the conditioning fluid is injected into the at least one first portion production well 106a, the at least one first portion production well 106a acts like an injection well in that it receives a fluid that is fed to the reservoir 102. When the

conditioning fluid is injected into at least one first portion injection well 104a and at least one first portion production well 106a, the stresses on the reservoir 102 may be balanced more quickly than if the conditioning fluid is only injected into at least one one first portion injection well 104a.

[0093] The conditioning process may end once the effective stresses on the reservoir 102 in the first portion first well pattern 1111 due to the overburden stress are alleviated and/or substantially balanced by the increased reservoir pore pressure. Whether or not the effective stresses on the reservoir 102 in the first portion first well pattern 1111 due to overburden stress have been alleviated and/or substantially balanced may be determined, but is not limited to being determined, by comparing the bottom hole pressures in the at least one first portion injection well 104a, the at least one first portion production well 106a, and/or at least one observation well to an estimated applied overburden stress due to its weight. The observation well may be a well that allows for the observation of parameters, such as but not limited to fluid levels and pressure changes, of one or more of the at least one first portion injection well 104a and the at least one first portion production well 106a. The magnitude of the effective stress applied by the overburden to the reservoir (e.g., overburden stress minus the reservoir pore pressure) at the end of the conditioning process is generally small (generally in the range of 10 to 500 kilopascals (kPa) out of the 1 megapascal (MPa) to 10MPa effective overburden stress that would have existed before the conditioning process, where the aforementioned ranges may include any number bounded by and/or within the preceding ranges depending on a depth of the reservoir, an initial pore pressure of the reservoir, and/or in situ stresses of the reservoir, of which the overburden stress may be one component).

[0094] Once the conditioning process ends, a first portion first differential pressure between the at least one first portion injection well 104a and the at least one first portion production well 106a may be created, 803 (Figure 6). Creating the first portion first differential pressure between the at least one first portion injection well 104a and the at least one first portion production well 106a may impose a pressure gradient. The creation of the first portion first differential pressure between the at least one first portion injection well 104a and the at least one first portion production well 106a may cause water or brine to flow in the subsurface formation 124. The water or brine may create fluid drag forces on solids in the subsurface formation 124. Once the first portion first differential pressure increases to a point where it overcomes the friction holding

the reservoir 102 in place, some of the first portion first well pattern primary sweep volume may move toward the at least one first portion production well 106a. In other words, the first portion first differential pressure may move or flow the subsurface formation 124 toward the at least one first portion production well 106a.

[0095] The first portion first differential pressure may be created by continuing to inject the conditioning fluid into the at least one first portion injection well 104a and by starting to produce the first portion first well pattern primary sweep volume from the at least one first portion production well 106a. The first portion first differential pressure may be created after the conditioning process ends. The flow of the conditioning fluid, fluid within the subterranean formation, and/or a portion of the first portion first well pattern primary sweep volume into the at least one first portion production well 106a may create the first portion first differential pressure near the at least one first portion production well 106a.

[0096] The first portion first differential pressure may be created by increasing a rate or pressure at the least one first portion injection well 104a. The rate or pressure may be increased such that it is higher than the rate or pressure used during the conditioning process.

[0097] Once the first portion first differential pressure alleviates and/or substantially balances the frictional stress opposing the motion or sliding of the material within the first portion first well pattern 1111, which has been reduced from the initial in situ values due to raising the pore pressure by injecting the conditioning fluid, the first portion first well pattern primary sweep volume may be produced via one or more of the at least one first portion production well 106a. The first portion first well pattern primary sweep volume produced may be the rest of the first portion first well pattern primary sweep volume that was not produced while creating the first portion first differential pressure. Producing the first portion first well pattern primary sweep volume may comprise mobilizing the first portion first well pattern primary sweep volume along a first subsurface formation path within the first portion first well pattern 1111 (i.e., first portion first subsurface formation path). The first portion first well pattern primary sweep volume moves along the first portion first subsurface formation path away from one or more of the at least one first portion injection well 104a to the one or more of the at least one first portion production well 106a. The first portion first well pattern primary sweep volume may be only a portion of the reservoir.

[0098] The first portion first well pattern primary sweep volume may be produced via one or more of the at least one first portion production well 106a, 804 (Figure 6). The one or more of the at least one first portion production well 106a may be configured to produce the first portion first well pattern primary sweep volume from the subsurface formation 124. The one or more of the at least one first portion production well 106a has a structure that enables it to produce the first portion first well pattern primary sweep volume. Examples of the structure may include, but are not limited to, an uncased wellbore or a cased wellbore with an opening or perforations that allow the first portion first well pattern primary sweep volume to flow into a well. The first portion first well pattern primary sweep volume travels in a direction 114 away from the reservoir 102 and toward the surface 112.

[0099] After being produced via the one or more of the at least one first portion production well 106a, the first portion first well pattern primary sweep volume may be fed to a pumping station 116. From the pumping station 116, the first portion first well pattern primary sweep volume may be processed in a facility 118 to remove at least a portion of the hydrocarbons 120 within the first portion first well pattern primary sweep volume that may then be sold. The hydrocarbons 120 can be sent to other facilities for refining or further processing such as but not limited to upgrading to produce upgraded hydrocarbons. The upgraded hydrocarbons may be sold. The hydrocarbons 120 may be combined with a diluent stream and then sent to other facilities and/or or sold. The portion of the first portion first well pattern primary sweep volume not sent to the other facilities for refining or further processing may enter a pumping station 110.

[0100] After creating the first portion first differential pressure between the at least one first portion injection well 104a and the at least one first portion production well 106a and to produce the first portion first well pattern primary sweep volume not produced while creating the first portion first differential pressure between the at least one first portion injection well 104a and the at least one first portion production well 106a, injection media may be injected into the at least one first portion injection well 104a. The at least one first portion injection well 104a may be configured to receive the injection media. The at least one first portion injection well 104a has a structure that enables it to receive the injection media and inject that media through an opening or perforations into the reservoir. Examples of structure may include, but are not limited to, an uncased wellbore or a cased wellbore. The injection media received by the at least one first

portion injection well 104a travels in the at least first portion injection well 104a in the direction 122. The injection media may be fed to the reservoir 102.

[0101] The injection media may be injected while producing the first portion first well pattern primary sweep volume and after creating the first portion first differential pressure. As the injection media is injected into the first portion first well pattern 1111 via the at least one first portion injection well 104a, the first portion first well pattern primary sweep volume is swept toward one or more of the at least one first portion production well 106a via the first portion first subsurface formation path to be produced from the one or more of the at least one first portion production well 106a. The injection media may fill the void that the produced first portion first well pattern primary sweep volume left in the reservoir 102.

[0102] The injection media may be injected into the first portion first well pattern 1111 via the at least one first portion injection well 104a until the injection media is produced by the at least one first portion production well 106a, 805 (Figure 6). Specifically, the injection media may be injected into the first portion first well pattern until breakthrough occurs at the at least one first portion production well 106a. The injection media being produced by the at least one first portion production well 106a marks the end of primary production within the first portion first well pattern 1111 when the injection media being produced comprises the reinjected sand. The reinjected sand may start to be produced from the at least one first portion production well 106a when a portion of the reinjected sand reaches the at least one first portion production well 106a, when the reinjected sand is travelling through the at least one first portion production well 106a, when the reinjected sand is exiting the at least one first portion production well 106a, or when the reinjected sand is moving through the surface processing facility 118.

[0103] The actual determination of when to stop injecting injection media via any of the one or more first portion injection well 104a into the first portion first well pattern 1111, because the injection media is being produced by the one or more of the at least one first portion production well 106a, may be determined by the sand breakthrough indicator.

[0104] After injecting the injection media into the first portion first well pattern 1111 and producing the first portion first well pattern primary sweep volume, the system and method may include increasing the reservoir pore pressure of the reservoir 102. Increasing the reservoir pore pressure may comprise injecting a conditioning fluid into the reservoir 102. The conditioning fluid may be injected into the reservoir 102 at one or more locations within the subsurface

formation 124. The conditioning fluid may be injected into any suitable location within the reservoir 102. The pressure of the conditioning fluid may allow the conditioning fluid to permeate through the portion of the reservoir 102 that contains hydrocarbons. As the conditioning fluid is injected, the reservoir pore pressure increases and may thereby alleviate and/or substantially balance the stresses on the reservoir 102 that are caused by the overburden stress. The pressure of the conditioning fluid may be sufficient to develop a substantially steady-state pressure profile within the reservoir 102.

[0105] Injecting the conditioning fluid into the reservoir 102 may comprise injecting the conditioning fluid via one or more of the at least one first portion injection well 104a, the at least one second portion injection well 104b, the at least one first portion production well 106a and the at least one second portion production well 106b. The at least one first portion injection well 104a, the at least one second portion injection well 104b, the at least one first portion production well 106a and the at least one second portion production well 106b may each have a structure that enable them to receive the conditioning fluid. Examples of the structure may include, but are not limited to, an uncased wellbore or a cased wellbore. The conditioning fluid travels in the at least one first portion injection well 104a, the at least one second portion injection well 104b, the at least one first portion production well 106a and/or the at least one second portion production well 106b in a direction 122 toward the reservoir 102.

[0106] When the conditioning fluid is injected into one or more of the at least one first portion injection well 104a, the at least one second portion injection well 104b, the at least one first portion production well 106a and the at least one second portion production well 106b, a porosity of the subsurface formation 124 may increase. The porosity of the subsurface formation 124 may increase because the reservoir 102 may comprise a sand particle network. The sand particle network may dilate or expand in volume as the effective stress due to the overburden stress is alleviated and/or substantially balanced by the increase in reservoir pore pressure. The increase in porosity may be accompanied by a decrease in the mechanical strength of the material within the reservoir 102 to a state where the material within the reservoir 102 may slide in a direction of one or more of the at least one first portion production well 106a and the at least one second portion production well 106b when a pressure gradient is imposed due to the flow of a fluid from one or more of the at least one first portion injection well 104a to the at least one first portion production well 106a and the at least one second portion injection well 104b to the

at least one second portion production well 106b. Increasing the initial porosity of the subsurface formation 124 may increase the permeability of the subsurface formation 124.

[0107] The injection of the conditioning fluid into one or more of the at least one first portion injection well 104a, the at least one second portion injection well 104b, the at least one first portion production well 106a and the at least one second portion production well 106b may be referred to as the conditioning process. In other words, the conditioning fluid may be injected into one or more of the at least one first portion injection well 104a, the at least one second portion injection well 104b, the at least one first portion production well 106a and the at least one second portion production well 106b during the conditioning process. When the conditioning fluid is injected into the at least one first portion production well 106a and/or the at least one second portion production well 106b, the at least one first portion production well 106a and/or the at least one second portion production well 106b act like an injection well in that they receive a fluid that is fed to the reservoir 102. When the conditioning fluid is injected into the at least one first portion injection well 104a, the at least one second portion injection well 104b, the at least one first portion production well 106a and at least one second portion production well 106b, the stresses on the reservoir 102 may be alleviated and/or substantially balanced more quickly than if the conditioning fluid is only injected into less than all of these.

[0108] The conditioning process may end once the effective stresses on the reservoir 102 due to the overburden stress are alleviated and/or substantially balanced by the increased reservoir pore pressure. Whether or not the effective stresses on the reservoir 102 due to overburden stress have been alleviated and/or substantially balanced may be determined, but is not limited to being determined, by comparing the bottom hole pressures in the at least one first portion injection well 104a, the at least one second portion injection well 104b, the at least one first portion production well 106a, the at least one second portion production well 106b, and/or at least one observation well to an estimated applied overburden stress due to its weight. The observation well may be a well that allows for the observation of parameters, such as but not limited to fluid levels and pressure changes, of one or more of the at least one first portion injection well 104a, the at least one second portion injection well 104b, the at least one first portion production well 106a and the at least one second portion production well 106b. The magnitude of the effective stress applied by the overburden to the reservoir (e.g., overburden stress minus the reservoir pore pressure) at the end of the conditioning process is generally small (generally in the range of 10 to 500

kilopascals (kPa) out of the 1 Megapascal (MPa) to 10MPa effective overburden stress that would have existed before the conditioning process, where the aforementioned ranges may include any number bounded by and/or within the preceding ranges depending on a depth of the reservoir, an initial pore pressure of the reservoir, and/or in situ stresses of the reservoir, of which the overburden stress may be one component).

[0109] Once the conditioning process ends, a second portion first differential pressure between the at least one second portion injection well 104b and the at least one second portion production well 106b may be created. Creating the second portion first differential pressure between the at least one second portion injection well 104b and the at least one second portion production well 106b may impose a pressure gradient. The creation of the second portion first differential pressure between the at least one second portion injection well 104b and the at least one second portion production well 106b may cause water or brine to flow in the subsurface formation 124. The water or brine may create fluid drag forces on solids in the subsurface formation 124. Once the second portion first differential pressure in the second portion first well pattern 1112 increases to a point where it overcomes the friction holding the reservoir 102 in place, some of a primary sweep volume within the second portion first well pattern (i.e., the second portion first well pattern primary sweep volume) may move toward the at least one second portion production well 106b. In other words, the second portion first differential pressure may move or flow the subsurface formation 124 toward the at least one second portion production well 106b.

[0110] The second portion first differential pressure may be created by continuing to inject the conditioning fluid into the at least one second portion injection well 104b and by starting to produce the second portion first well pattern primary sweep volume from the at least one second portion production well 106b. The second portion first differential pressure may be created after the conditioning process ends. The flow of the conditioning fluid, fluid within the subterranean formation and/or a portion of the second portion first well pattern primary sweep volume into the at least one second portion production well 106b may create the second portion first differential pressure near the at least one second portion production well 106b.

[0111] The second portion first differential pressure may be created by increasing a rate or pressure at the least one second portion injection well 104b. The rate or pressure may be increased such that it is higher than the rate or pressure used during the conditioning process.

[0112] Once the second portion first differential pressure alleviates or substantially balances the overburden stress opposing the motion or sliding of the material within the second portion first well pattern 1112, which have been reduced from the initial in situ values due to raising the pore pressure by injecting the conditioning fluid, the second portion first well pattern primary sweep volume may be produced via one or more of the at least one second portion production well 106b. The second portion first well pattern primary sweep volume produced may be the rest of the second portion first well pattern primary sweep volume that was not produced while creating the second portion first differential pressure. Producing the second portion first well pattern primary sweep volume may comprise mobilizing the second portion first well pattern primary sweep volume along a second portion first subsurface formation path within the second portion first well pattern 1112 (i.e., second portion first subsurface formation path). The second portion first well pattern primary sweep volume moves along the second portion first subsurface formation path away from one or more of the at least one second portion injection well 104b to the one or more of the at least one second portion production well 106b. The second portion first well pattern primary sweep volume may be only a portion of the reservoir.

[0113] The second portion first well pattern primary sweep volume may be produced via one or more of the at least one second portion production well 106b. The one or more of the at least one second portion production well 106b may be configured to produce the second portion first well pattern primary sweep volume from the subsurface formation 124. The one or more of the at least one second portion production well 106b has a structure that enables it to produce the second portion first well pattern primary sweep volume. Examples of the structure may include, but are not limited to, an uncased wellbore or a cased wellbore with an opening or perforations that allow the second portion first well pattern primary sweep volume to flow into a well. The second portion first well pattern primary sweep volume travels in a direction 114 away from the reservoir 102 and toward the surface 112.

[0114] After being produced via the one or more of the at least one second portion production well 106b, the second portion first well pattern primary sweep volume may be fed to a pumping station 116. From the pumping station 116, the second portion first well pattern primary sweep volume may be processed in a facility 118 to remove at least a portion of the hydrocarbons 120 within the second portion first well pattern primary sweep volume that may then be sold. The hydrocarbons 120 can be sent to other facilities for refining or further

processing such as but not limited to for upgrading to produce upgraded hydrocarbons. The upgraded hydrocarbons may be sold. The hydrocarbons 120 may be combined with a diluent stream and then sent to other facilities and/or or sold. The portion of the second portion first well pattern primary sweep volume not sent to the other facilities for refining or further processing may enter a pumping station 110.

[0115] After creating the second portion first differential pressure between the at least one second portion injection well 104b and the at least one second portion production well 106b and to produce the second portion first well pattern primary sweep volume not produced while creating the second portion first differential pressure between the at least one second portion injection well and the at least one second portion production well, injection media may be injected into the at least one second portion injection well 104b. The at least one second portion injection well 104b may be configured to receive the injection media. The at least one second portion injection well 104b has a structure that enables it to receive the injection media and inject that media through an opening or perforations into the reservoir. Examples of structure may include, but are not limited to, an uncased wellbore or a cased wellbore. The injection media received by the at least one second portion injection well 104b travels in the at least one second portion injection well 104b in the direction 122. The injection media may be fed to the reservoir 102.

[0116] The injection media may be injected while producing the second portion first well pattern primary sweep volume and after creating the second portion first differential pressure. As the injection media is injected into the second portion first well pattern 1112 via the at least one second portion injection well 104b, the second portion first well pattern primary sweep volume is swept toward one or more of the at least one second portion production well 106b via the second portion first subsurface formation path to be produced from the one or more of the at least one second portion production well 106b. The injection media may fill the void that the produced second portion first well pattern primary sweep volume left in the reservoir 102.

[0117] The injection media may be injected into the second portion first well pattern 1112 via the at least one second portion injection well 104b until the injection media is produced by the at least one second portion production well 106b. Specifically, the injection media may be injected into the second portion first well pattern until breakthrough occurs at the at least one second portion production well 106b. The reinjected sand may start to be produced from the at

least one second portion production well 106b when a portion of the reinjected sand reaches the at least one second portion production well 106b, when the reinjected sand is travelling through the at least one second portion production well 106b, when the reinjected sand is exiting the at least one second portion production well 106b, or when the reinjected sand is moving through the surface processing facility 118. The injection media being produced by the at least one second portion production well 106b marks the end of primary production within the second portion first well pattern 1112 when the injection media being produced comprises the reinjected sand.

[0118] The actual determination of when to stop injecting injection media via any of the one or more second portion injection well 104b into the second portion first well pattern 1112, because the injection media is being produced by the one or more of the at least one second portion production well 106b, may be determined by the sand breakthrough indicator.

[0119] After injecting the injection media into the first portion first well pattern 1111 and producing the first portion first well pattern primary sweep volume and before increasing the reservoir pore pressure, creating the second portion first differential pressure, producing the second portion first well pattern primary sweep volume and injecting the injection media into the second portion first well pattern, or after injecting the injection media into the first portion first well pattern 1111 and producing the first portion first well pattern primary sweep volume and after increasing the reservoir pore pressure, creating the second portion first differential pressure, producing the second portion first well pattern primary sweep volume and injecting the injection media into the second portion first well pattern, the system and method may comprise reducing the reservoir pore pressure. Reducing the reservoir pore pressure may allow the overburden stress to be at least partially reapplied to the first portion first well pattern 1111 and/or the second portion first well pattern 1112, respectively, thereby recompressing at least a portion of the reservoir 102, reducing the porosity and or increasing the mechanical stiffness of a portion of the sand matrix comprising the reservoir 102. One or more of the at least one first portion injection well 104a and the at least one first portion production well 106a and one or more of the at least one second portion injection well 104b and the at least one second portion production well 106b may allow for this recompression of the first portion first well pattern 1111 and/or the second portion first well pattern 1112, respectively, by being wells for withdrawing fluids from the reservoir in order to lower the reservoir pore pressure. The reservoir pore pressure may be

reduced by ceasing the injection of the injection media into the at least one first portion injection well 104a and the at least one second portion injection well 104b. The reservoir pore pressure may be reduced by ceasing production of all but fluid (e.g., preferentially only producing the fluid) through the one or more of the at least one first portion production well 106a and the at least one second portion production well 106b. The reservoir pore pressure may be reduced by ceasing injection of injection media into the at least one first portion injection well 104a and allowing the reservoir pore pressure to drop due to leak off or equilibration of the reservoir pore pressure and/or ceasing injection of injection media into the at least one second portion injection well 104b and allowing the reservoir pore pressure to drop due to leak off or equilibration of the reservoir pore pressure. The reservoir pore pressure may be reduced by ceasing injection of injection media into the at least one first portion injection well 104a and by ceasing production of the primary sweep volume by the at least one first portion production well 106a and allowing the reservoir pore pressure to drop due to leak off or equilibration of the reservoir pore pressure and/or by ceasing injection of injection media into the at least one second portion injection well 104b and by ceasing production of the primary sweep volume by the at least one second portion production well 106b and allowing the reservoir pore pressure to drop due to leak off or equilibration of the reservoir pore pressure. The reservoir pore pressure leaks off into one or more portions of the reservoir that are not being targeted for production.

[0120] Reducing the reservoir pore pressure to recompact at least the portion of the first portion first well pattern 1111 and/or the second portion first well pattern 1112 may seal the first portion first subsurface formation path 1300 and/or the second portion first subsurface formation path 1301, respectively, , which is beneficial. Sealing the first portion first subsurface formation path and/or the second portion first subsurface formation path after the hydrocarbons are produced during for example, primary production, will promote production from the reservoir along other subsurface formation paths (e.g. where production has not yet occurred). Sealing the first portion first subsurface formation path and/or the second portion first subsurface formation path helps make it possible to produce a portion of the reservoir 102 that was not previously produced, thereby helping make it possible to enhance heavy oil recovery. The process of reducing the reservoir pore pressure may be referred to as a recompaction process.

[0121] While producing the primary sweep volume of and/or injecting the injection media into the first portion first well pattern and/or the second portion first well pattern, the reservoir

pore pressure may be reduced. This reduction may occur as a mitigation during a process upset. One example of a process upset includes, but is not limited to, when the injection media includes too much water. When the injection media includes too much water, the primary sweep volume may not be able to be mobilized or only a portion of the primary sweep volume may be mobilized with a portion of the injection media bypassing the primary sweep volume. When the primary sweep volume is not able to be mobilized or only a portion of the primary sweep volume is mobilized, the reservoir pore pressure may be reduced in a manner similar to how the reservoir pore pressure is reduced during the previously described recompression process. After recompressing the subsurface formation, injection media may again be injected so that primary sweep volume may be produced.

[0122] While producing the primary sweep volume of and/or injecting the injection media into the first portion first well pattern and/or the second portion first well pattern, the reservoir pore pressure may be increased. This increase may occur as a mitigation during a process upset. One example of a process upset includes, but is not limited to, when the reservoir pore pressure has not been increased enough to mobilize the primary sweep volume when the injection media is injected. The reservoir pore pressure may not be increased enough if the conditioning process ends before the effective stresses on the reservoir 102, due to the overburden stress, are alleviated and/or substantially balanced by the increased reservoir pore pressure. The reservoir pore pressure may be increased in a similar manner to how the reservoir pore pressure is increased during the previously described conditioning process. Increasing the reservoir pore pressure may be stopped when it appears that the effective stresses on the reservoir 102, due to the overburden stress, have been alleviated and/or substantially reduced by the increased reservoir pore pressure. After increasing the reservoir pore pressure has stopped, injection media may again be injected so that primary sweep volume may be produced.

[0123] While producing the primary sweep volume of and/or injecting the injection media into the first portion first well pattern and/or the second portion first well pattern, the reservoir pore pressure may be reduced and then increased. This reduction and increase may occur as a mitigation during a process upset. One example of a process upset includes, but is not limited to, when the injection media includes too much water, so the reservoir pore pressure is reduced in a manner similar to how the reservoir pore pressure is reduced during the previously described recompression process, and then the reservoir pore pressure is not high enough for the primary

sweep volume to be mobilized, so the reservoir pore pressure is increased in a similar manner to how the reservoir pore pressure is increased during the previously described conditioning process. After the reduction and increase stops, injection media may again be injected so that primary sweep volume may be produced.

[0124] While producing the primary sweep volume of and/or injecting the injection media into the first portion first well pattern and/or the second portion first well pattern, the reservoir pore pressure may be increased and then reduced. This increase and reduction may occur as a mitigation during a process upset. One example of a process upset includes, but is not limited to, when the reservoir pore pressure is not high enough for the primary sweep volume to be mobilized, so the reservoir pore pressure is increased in a similar manner to how the reservoir pore pressure is increased during the previously described conditioning process, and then the injection media includes too much water, so the reservoir pore pressure is reduced in a manner similar to how the reservoir pore pressure is reduced during the previously described recompaction process. After the increase and reduction stops, injection media may again be injected so that primary sweep volume may be produced.

[0125] After the injection media ceases being injected into the at least one first portion injection well 104a and the first portion first well pattern primary sweep volume ceases being produced and/or the injection media ceases being injected into the at least one second portion injection well 104b and the second portion first well pattern primary sweep volume ceases being produced, the method and system may comprise recompleting at least one of (1) recompleting one or more of the at least one production well 106 as a recompleted injection well 105 and (2) shutting in one or more of the at least one injection well 104 and/or at least one or (1)recompleting one or more of the at least one injection well 104 as a recompleted production well 107 and (2) shutting in one or more of the at least one production well 106a, 106bb (Figures 4-5). A recompleted first portion injection well and a recompleted second portion injection well may interchangeably be referred to as a recompleted production well. A recompleted first portion production well and a recompleted second portion production well may interchangeably be referred to as a recompleted production well.

[0126] Recompleting and shutting in may be referred to as a recompletion process. The recompleted production well 107 may comprise an injection well 104 that was recompleted to act as a production well such that the recompleted production well 107 produces a fluid or a second

portion of the reservoir material. In other words, the recompleted production well 107 may have previously acted as an injection well 104. The recompleted production well 107 may have previously acted as an injection well 104 during primary production. The recompleted production well 107 may comprise one or more recompleted production wells 107. The recompleted production well 107 may comprise any amount of wells bounded by and including the aforementioned range. The recompleted injection well 105 may comprise a production well 106 that was recompleted to act as an injection well such that the recompleted injection well 105 receives a fluid or injection media to inject into the reservoir. In other words, the recompleted injection well 105 may have previously acted as a production well 106. The recompleted injection well 105 may have previously acted as a production well 106 during primary production. The recompleted injection well 105 may comprise one or more recompleted injection wells 105. The recompleted injection well 105 may comprise any amount of wells bounded by and including the aforementioned range.

[0127] Reducing the reservoir pore pressure, after the injection media ceases being injected and the primary sweep volume ceases being produced, may occur before at least one of recompleting and shutting in.

[0128] After recompleting and/or shutting in, the method and system may comprise increasing the reservoir pore pressure by injecting a reconditioning fluid into the subsurface formation. The reconditioning fluid may be injected via one or more of the at least one first portion injection well 104a, the at least one second portion injection well 104b, the at least one first portion production well 106a, the at least one second portion production well 106b, the recompleted production well 105 and the recompleted injection well 107. As the reconditioning fluid is injected, the reservoir pore pressure may increase to alleviate and/or substantially balance the stresses on the reservoir 102 that are caused by an overburden stress of the overburden 108 on the reservoir 102. The pressure of the reconditioning fluid injected may help make it possible to increase the reservoir pore pressure.

[0129] When the reconditioning fluid is injected, a porosity of the subsurface formation 124 may increase. Increasing the porosity of the subsurface formation 124 may increase a permeability of the subsurface formation 124 and partially or totally break up or disaggregate (through shear dilation) a portion of the shale and/or mudstone layers that may be embedded within the reservoir. Increasing the porosity and permeability may remove the shale and/or

mudstone layers from acting as baffles and/or barriers to the flow within the subsurface formation 124. The pressure of the reconditioning fluid injected may help make it possible to increase the initial porosity and the permeability.

[0130] The injection of the reconditioning fluid into the subsurface formation 124 may be referred to as the reconditioning process. The reconditioning process may end once the stresses on the reservoir 102 that are caused by the overburden stress are alleviated and/or substantially balanced by the reconditioning process. The magnitude of the effective stress applied by the overburden to the reservoir (e.g., overburden stress minus pore pressure) at the end of the reconditioning process is generally small (generally in the range of 10 to 500 kilopascals (kPa) out of the 1 Megapascal (MPa) to 10MPa overburden stress that would have existed before the reconditioning process, where the aforementioned ranges may include any number bounded or within the preceding ranges).

[0131] After the reconditioning process ends, a second differential pressure may be created between (a) the recompleted production well 107 and the at least one injection well 104a, 104b or (b) the recompleted injection well 105 and the at least one production well 106a, 106b (Figures 4-5). Creating the second differential pressure may impose a pressure gradient. The creation of the second differential pressure may occur after recompleting and shutting in. The creation of the second differential pressure may cause water or brine to flow into the subsurface formation 124. The water or brine may create fluid drag forces on solids in the subsurface formation 124. Once the second differential pressure in a given portion of the subsurface formation 124 near the recompleted production well 107 or the at least one production well 106a, 106b increases to a point where it overcomes the friction holding the reservoir 102 in place, some of a secondary sweep volume 131 may move toward the recompleted production well 107 or the at least one production well 106a, 106b. In other words, the second differential pressure may move or flow the subsurface formation 124 toward the recompleted production well 107 or the at least one production well 106a, 106b.

[0132] The second differential pressure may be created by continuing to inject the reconditioning fluid into the recompleted injection well 105 or the at least one injection well 104a, 104b and by starting to produce secondary sweep volume from the recompleted production well 107 or the at least one production well 106a, 106b. The flow of the reconditioning fluid, fluid within the subterranean formation, a portion of the primary sweep volume, and/or a portion

of the secondary sweep volume, into the recompleted production well 107 or the at least one production well 106a, 106b may create the second differential pressure near the recompleted production well 107 or the at least one production well 106a.

[0133] The second differential pressure may be created by increasing a rate or pressure at the recompleted injection well 105 or the least one injection well 104a, 104b. The rate or pressure may be increased such that it is higher than the rate or pressure used during the reconditioning process.

[0134] Once the second differential pressure is large enough to overcome the friction holding the portion of the reservoir 102 near the recompleted production well 107 or the at least one production well 106a, 106b, secondary sweep volume may be produced via one or more of the recompleted production well 107 and the at least one production well 106a, 106b. The secondary sweep volume produced may be the rest of the secondary sweep volume that was not produced while creating the second differential pressure.

[0135] Producing the secondary sweep volume may comprise mobilizing the secondary sweep volume along a second subsurface formation path 302 within the subsurface formation 124. The second subsurface formation path may be different from the first and second portion first subsurface formation path. When the second subsurface formation path is different from the first and second portion first subsurface formation path, the recovery of heavy oil may be enhanced because a different portion of the first well pattern may be swept. The swept portion of the second subsurface formation path is the secondary sweep volume 131 that may be produced. The second subsurface formation path may be different from the first and second portion first subsurface formation path because the subsurface formation 124 undergoes the recompleting and reconditioning processes after the primary sweep volume 130 is produced. The reconditioning process helps to seal the first and second portion first subsurface formation path 1301 so that a new portion of the well pattern can be produced. The recompletion process helps provide an alternative path for reinjection media to enter the subsurface formation 124 and for secondary sweep volume to be produced from the subsurface formation 124 so that a new portion of the reservoir 102 can be swept and produced.

[0136] During production, the secondary sweep volume moves along the second subsurface formation path away from the one or more of the at least one recompleted injection well 105 and the at least one injection well 104a, 104b to the one or more of the at least one recompleted

production well 107 or the one more more of the at least one production well 106a, 106b, respectively. The secondary sweep volume may only be a portion of the reservoir.

[0137] The secondary sweep volume may be produced via one or more of the recompleted production well 107 and the at least one production well 106a, 106b. The one or more of the recompleted production well 107 and the at least one production well 106a, 106b may be configured to produce the secondary sweep volume from the first well pattern. The one or more of the recompleted production well 107 and the at least one production well 106a, 106b each have a structure that enable them to produce the secondary sweep volume. Examples of structure may include, but are not limited to, a caseless wellbore or a cased wellbore. The secondary sweep volume travels in a direction 114 away from the reservoir 102 and toward the surface 112 such that a secondary sweep volume may be swept in a second subsurface formation path. Similar to primary production, secondary production may end when breakthrough occurs.

[0138] After being produced via the one or more of the recompleted production well 107 and the at least one production well 106a, 106b the secondary sweep volume may be fed to a pumping station 116. From the pumping station 116, the secondary sweep volume may be processed in a facility 118 to remove at least a portion of the hydrocarbons 120 within the secondary sweep volume, which may then be sold. The hydrocarbons 120 can be sent to other facilities for refining or further processing, such as but not limited to for upgrading to produce upgraded hydrocarbons. The upgraded hydrocarbons may be sold. The hydrocarbons 120 may be combined with a diluent stream and then sent to other facilities and/or sold. The portion of the secondary sweep volume not sent to the other facilities for refining or further processing may enter a pumping station 110.

[0139] While producing the secondary sweep volume and/or injecting the reinjection media, the reservoir pore pressure may be reduced, increased, reduced and then increased, or increased and then reduced. The reduction, increase, reduction and then increase, or increase and then decrease of the reservoir pore pressure may occur during a process upset in a similar and/or identical way to that described above for when the reservoir pore pressure is reduced, increases, reduced and then increased or increased and then decreased while producing the primary sweep volume and/or injecting the injection media into the first portion first well pattern and/or the second portion first well pattern.

[0140] All of the above steps may be performed at a first elevation or depth first and then, after all the steps are completed, the above steps may be performed at a second elevation. The second elevation or depth may be above the first elevation. In other words, the second elevation may be closer to the Earth's surface than the first elevation. The second elevation may be farther from the Earth's surface than the first elevation; the first elevation may be closer to the Earth's surface than the second elevation. It may be advantageous to perform at a first elevation first and then a second elevation to increase the total production for a given set of wells. After performing the above steps at a second elevation, the steps could be performed at a third elevation and so on.

[0141] It is important to note that the steps depicted in Figure 6 are provided for illustrative purposes only and a particular step may not be required to perform the inventive methodology. The claims, and only the claims, define the inventive system and methodology.

[0142] Disclosed aspects may be used in hydrocarbon management activities. As used herein, "hydrocarbon management" or "managing hydrocarbons" includes hydrocarbon extraction, hydrocarbon production, hydrocarbon exploration, identifying potential hydrocarbon resources, identifying well locations, determining well injection and/or extraction rates, identifying reservoir connectivity, acquiring, disposing of and/or abandoning hydrocarbon resources, reviewing prior hydrocarbon management decisions, and any other hydrocarbon-related acts or activities. The term "hydrocarbon management" is also used for the injection or storage of hydrocarbons or CO₂, for example the sequestration of CO₂, such as reservoir evaluation, development planning, and reservoir management. The disclosed methodologies and techniques may be used to extract hydrocarbons from a subsurface region. Hydrocarbon extraction may be conducted to remove hydrocarbons from the subsurface region, which may be accomplished by drilling a well using oil drilling equipment. The equipment and techniques used to drill a well and/or extract the hydrocarbons are well known by those skilled in the relevant art. Other hydrocarbon extraction activities and, more generally, other hydrocarbon management activities, may be performed according to known principles.

[0143] The system and method discussed above are different from waste injection. In the system and method discussed above, the goal is to displace the reservoir itself. In other words, in the system and method discussed above, the goal is to produce the reservoir itself, which includes producing hydrocarbons within the reservoir as well as other components, such as but not limited to sand, within a reservoir. The reservoir is produced by displacing the reservoir with

injection media and/or reinjection media. In waste injection, the injection media does not displace the reservoir, but is rather injected into the reservoir with no accompanied production.

[0144] The system and method discussed above are different from hydrocarbons waterflooding. In waterflooding, water may be injected into the subsurface to cause a pressure differential between sets of injection wells and production wells to aid in the production of hydrocarbons from the production wells. Waterflooding is generally a “secondary” or “enhanced” hydrocarbons recovery concept as it increases the pressure in the reservoir locally to drive more hydrocarbons out of the reservoir through creation of a pressure differential between sets of injection wells or production wells.

[0145] The basic physics that govern waterflooding are the flow of fluids through a porous and/or permeable media. The physics of flow through porous and/or permeable media show that the pressures between injection wells and production wells is governed by the rate at which fluids are injected and produced and the mobility of those fluids through the porous and/or permeable media. That mobility is controlled by the permeability of the media divided by the viscosity of the fluid flowing in the media. Thus for the single media (i.e. single permeability), water with it viscosity of 1 (centipoise) cP will have a higher mobility than hydrocarbons which generally have a higher to much higher viscosity than water (generally 5-500 cP). It is this physics that dictates that when the injected fluid (most often water) “breaks through” to a production well during a waterflood, the production rate of hydrocarbons drops dramatically due both to the higher mobility of the water versus the hydrocarbons and to the drop in pressure differential between injection wells and production wells due to the ease for water now to flow between the injection wells and production wells. This break through of water may substantially decrease the effectiveness of an injection well to aid in the production of hydrocarbons from production wells in the area as for the same injection rate, as its injection pressure now is much lower and thus its pressure differential even with non-break through production wells is much less.

[0146] The system and method described above involve the flow of the porous and/or permeable media itself as opposed to the flow of fluids through a porous and/or permeable media. The flow of fluid relative to the porous and/or permeable media exerts a drag. When the drag balances or overcomes the frictional stresses holding the porous and/or permeable media in the reservoir in place, the reservoir will begin to flow. When the reservoir flows, the pressure

differential is proportional to the frictional stresses rather than being proportional to the flow rate of fluid as it is in waterflood. This completely changes the physics of the process from that of waterflooding. As the pressure differential is proportional to the frictional stresses opposing the flow of the reservoir, it is also proportional to those stresses normal to the direction of flow. Those normal stresses are the effective overburden stresses applied to that porous and/or permeable media. The effective overburden stresses applied to the porous and/or permeable media are inversely proportional to the pore pressure. During reservoir flow, the effective overburden stresses applied to both the flowing and nonflowing porous and/or permeable media evolve and vary. This is different from waterflooding where production is fairly independent of stresses and stress evolution. The effective overburden stress in the system and method described above may impact the pressure gradient needed to flow the porous and/or permeable media between the wells. Specifically, for a given portion of porous and/or permeable media, the higher the effective overburden stress – the higher the required pressure differential for reservoir flow. If the overall pressure differential is dominated by the flow of porous and/or permeable media via a low stress path, the higher stressed porous and/or permeable media will not flow.

[0147] The different physics of fluid flow with porous and/or permeable media flow envisioned for the system and method described above relative to waterflooding makes it extremely unlikely that one of ordinary skill in the art of flow through porous and/or permeable media would extrapolate waterflooding to the flow of porous and/or permeable media as described for the above system and method.

[0148] It should be noted that the orientation of various elements may differ, and that such variations are intended to be encompassed by the present disclosure. It is recognized that features of the disclosure may be incorporated into other examples.

[0149] It should be understood that the preceding is merely a detailed description of this disclosure and that numerous changes, modifications, and alternatives can be made in accordance with the disclosure here without departing from the scope of the disclosure. The preceding description, therefore, is not meant to limit the scope of the disclosure. Rather, the scope of the disclosure is to be determined only by the appended claims and their equivalents. It is also contemplated that structures and features embodied in the present examples can be altered, rearranged, substituted, deleted, duplicated, combined, or added to each other.

CLAIMS:

1. A method for enhancing recovery of heavy oil from a reservoir within a subsurface formation, comprising:

(a) increasing a reservoir pore pressure of the reservoir, wherein the increasing in the reservoir pore pressure is sufficient to alleviate or balance effective stresses on the reservoir due to overburden stress on the reservoir, and, wherein the reservoir includes a first well pattern having at least one injection well and at least one production well and wherein the first well pattern has the first portion first well pattern having at least one first portion injection well of the at least one injection well and at least one first portion production well of the at least one production well and wherein the first well pattern has a second portion first well pattern having at least one second portion injection well of the at least one injection well and at least one second portion production well of the at least one production well, then;

(b) creating a first portion first differential pressure between the at least one first portion injection well and the at least one first portion production well, then;

(c) producing primary sweep volume comprising sand from the first portion first well pattern via one or more of the at least one first portion production well; and

(d) injecting an injection media comprising water and reinjected sand into the subsurface formation until the injection media is produced by the one or more of the at least one first portion production well.

2. The method of claim 1, wherein the at least one first portion injection well is the at least one second portion injection well.

3. The method of claim 2, wherein the at least one first portion production well is separate from the at least one second portion production well.

4. The method of claim 1, wherein the at least one first portion production well is the at least one second portion production well.

5. The method of claim 4, wherein the at least one first portion injection well is separate from the at least one second portion injection well.
6. The method of claim 1, wherein one or more of the at least one first portion injection well is separate from one or more of the at least one second portion injection well.
7. The method of claim 1, wherein the one or more of the at least one first portion production well is separate from one or more of the at least one second portion production well.
8. The method of claim 1, wherein the first well pattern consists of the first portion first well pattern and the second portion first well pattern.
9. The method of claim 1, wherein the first well pattern comprises the first portion first well pattern and the second portion first well pattern.
10. The method of claim 1, wherein the first well pattern comprises one of a five-spot well pattern, an inverted five-spot well pattern, a seven-spot well pattern and a nine-spot well pattern.
11. The method of claim 1, wherein creating the first portion first differential pressure and producing the primary sweep volume from the first portion first well pattern occur simultaneously.
12. The method of claim 1, further comprising during at least one of creating the first portion differential pressure and producing the primary sweep volume from the first portion first well pattern, one of reducing the reservoir pressure, increasing the reservoir pressure, reducing the reservoir pressure and then increasing the reservoir pressure, and increasing the reservoir pressure and then reducing the reservoir pressure.

13. The method of claim 1, wherein creating the first portion first differential pressure comprises mobilizing the primary sweep volume from the first portion first well pattern along a first portion first subsurface formation path within the subsurface formation.

14. The method of claim 1, further comprising:

- (e) increasing the reservoir pore pressure , then;
- (f) creating a second portion first differential pressure between the at least one second portion injection well and the at least one second portion production well, then;
- (g) producing primary sweep volume from the second portion first well pattern via one or more of the at least one second portion production well; and
- (h) injecting the injection media into the subsurface formation until the injection media is produced by the one or more of the at least one second portion production well.

15. The method of claim 1, further comprising before performing (e) - (h) and after performing (a) – (d):

- (i) reducing the reservoir pore pressure;
- (j) recompleting at least one of (1) recompleting one or more of the at least one production well as a recompleted injection well and (2) shutting in one or more of the at least one injection well and/or at least one of (1) recompleting one or more of the at least one injection well as a recompleted production well and (2) shutting in one or more of the at least one production well, then;
- (k) increasing the reservoir pore pressure by injecting a reconditioning fluid into the subsurface formation.

16. The method of claim 15, further comprising:

- creating a second differential pressure between the recompleted production well and the at least one injection well or the recompleted injection well and the at least one production well; and
- producing a secondary sweep volume from the subsurface formation.

17. The method of claim 1, wherein increasing the reservoir pore pressure comprises injecting a conditioning fluid into the first well pattern.

18. The method of claim 17, wherein injecting the conditioning fluid into the first well pattern comprises injecting the conditioning fluid via one or more of the at least one first portion injection well, the at least one first portion production well, the at least one second portion injection well and the at least one second portion production well.

19. A method for enhancing recovery of heavy oil from a reservoir within a subsurface formation, comprising:

(a) creating a first well pattern within a subsurface formation, the first well pattern having at least one injection well and at least one production well, wherein the first well pattern has a first portion first well pattern having at least one first portion injection well of the at least one injection well and at least one first portion production well of the at least one production well and wherein the first well pattern has a second portion first well pattern having at least one second portion injection well of the at least one injection well and at least one second portion production well of the at least one production well;

(b) increasing a reservoir pore pressure of the reservoir, wherein the increasing in the reservoir pore pressure is sufficient to alleviate or balance effective stresses on the reservoir due to overburden stress on the reservoir, then;

(c) creating a second portion first differential pressure between the at least one first portion injection well and the at least one first portion production well, then;

(d) producing primary sweep volume comprising sand from the first portion first well pattern via one or more of the at least one first portion production well; and

(e) injecting an injection media comprising water and reinjected sand into the subsurface formation until the injection media is produced by the one or more of the at least one first portion production well.

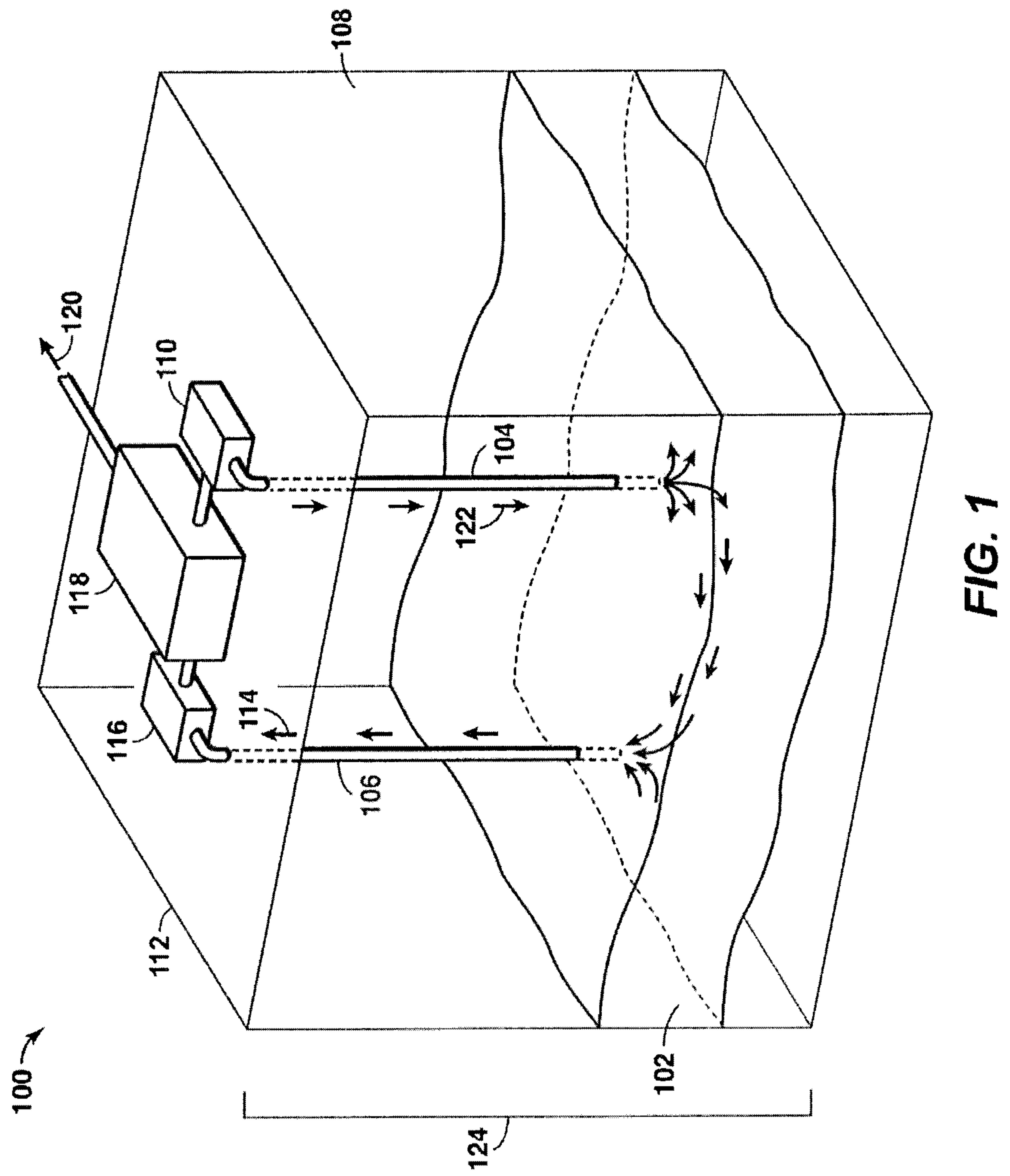
20. The method of claim 19, further comprising:

(f) increasing the reservoir pore pressure, then;

- (g) creating a second portion first differential pressure between the at least one second portion injection well and the at least one second portion production well, then;
- (h) producing primary sweep volume from the second portion first well pattern via one or more of the at least one second portion production well; and
- (i) injecting the injection media into the subsurface formation until the injection media is produced by the one or more of the at least one second portion production well.

21. The method of claim 20, further comprising before performing (f) - (i) and after performing (a) - (e):

- (j) reducing the reservoir pore pressure;
- (k) recompleting at least one of (1) recompleting one or more of the at least one production well as a recompleted injection well and (2) shutting in one or more of the at least one injection well and/or at least one of (1) recompleting one or more of the at least one injection well as a recompleted production well and (2) shutting in one or more of the at least one production well, then;
- (l) increasing the reservoir pore pressure by injecting a reconditioning fluid into the subsurface formation.



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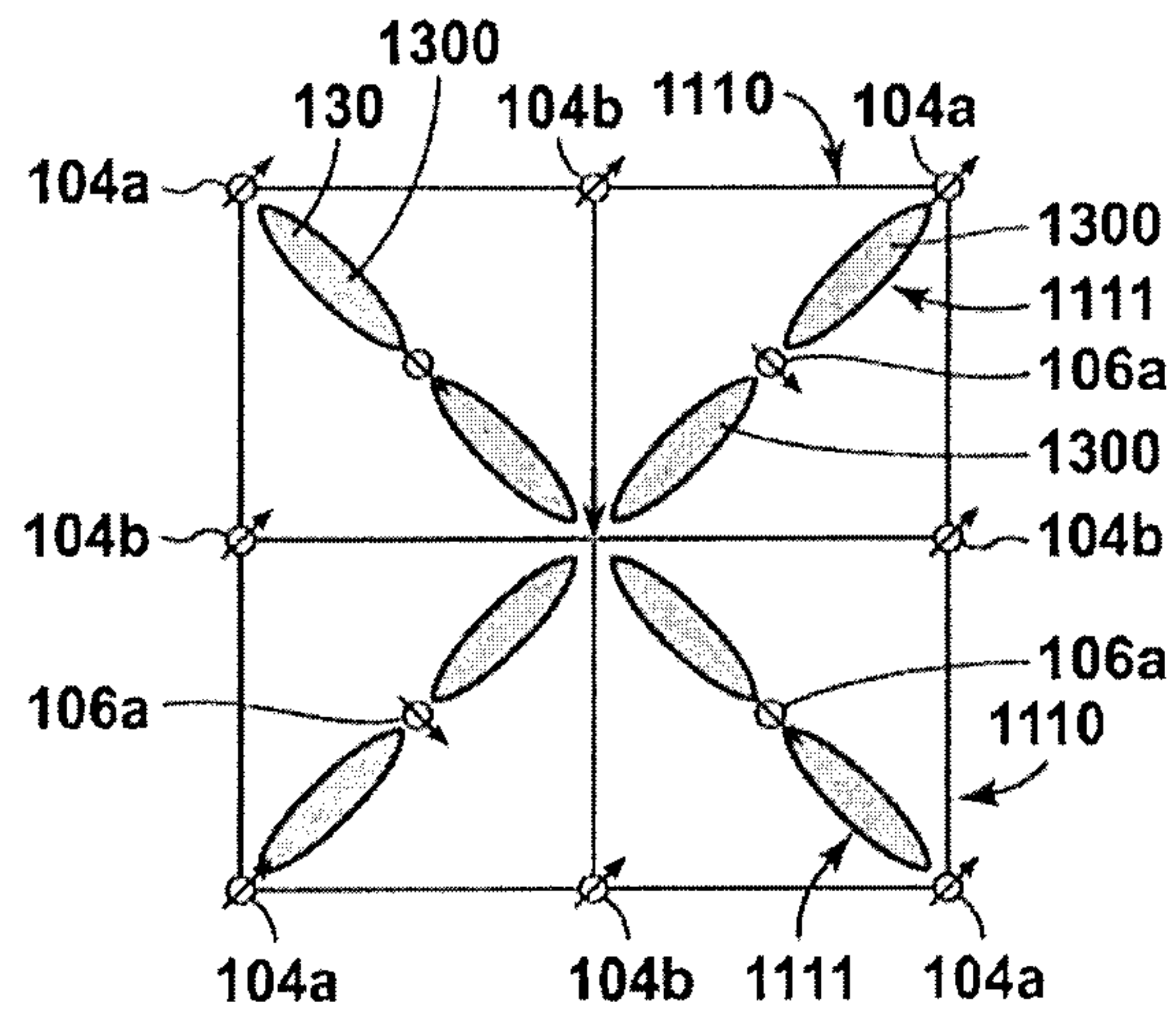


FIG. 2A

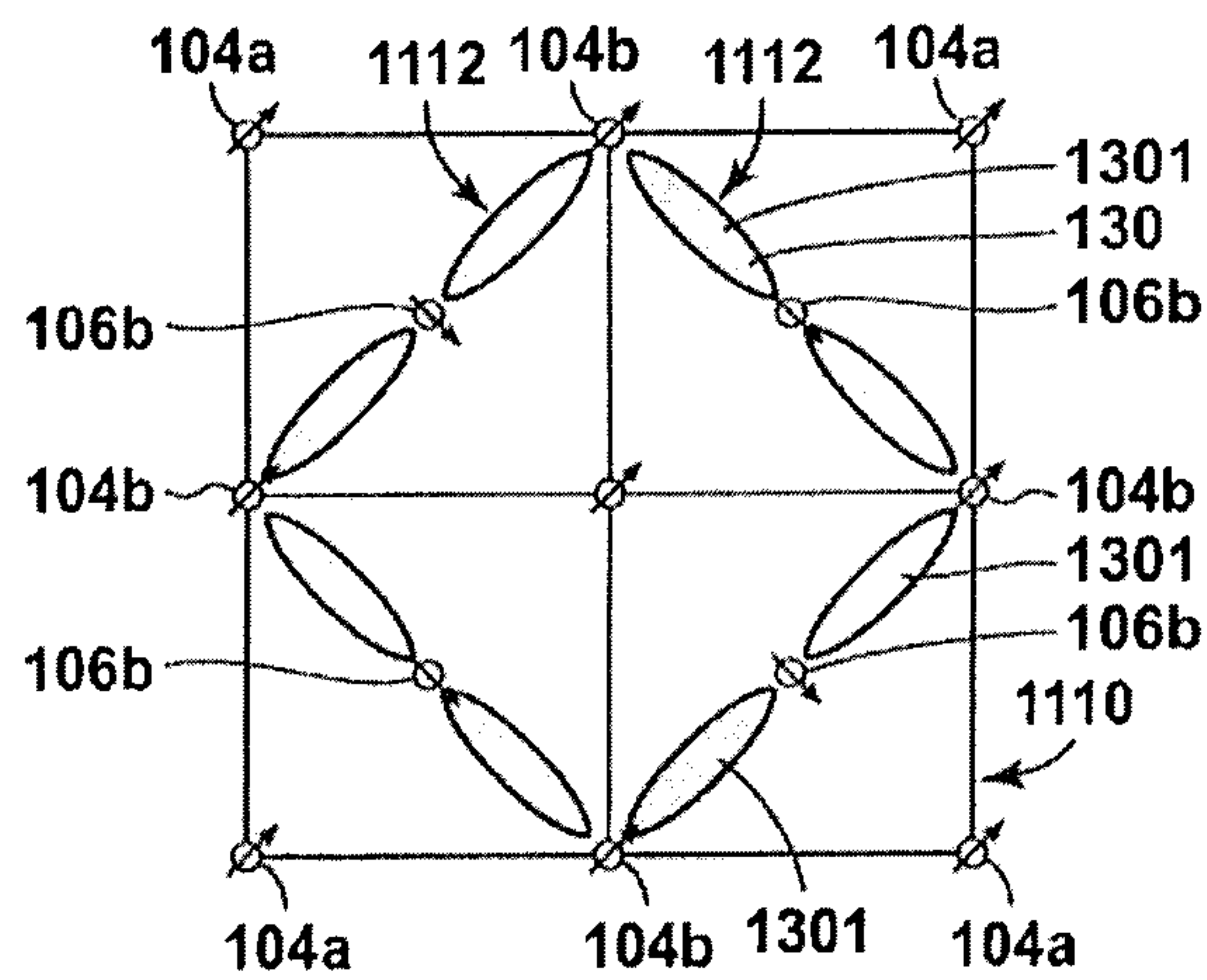


FIG. 2B

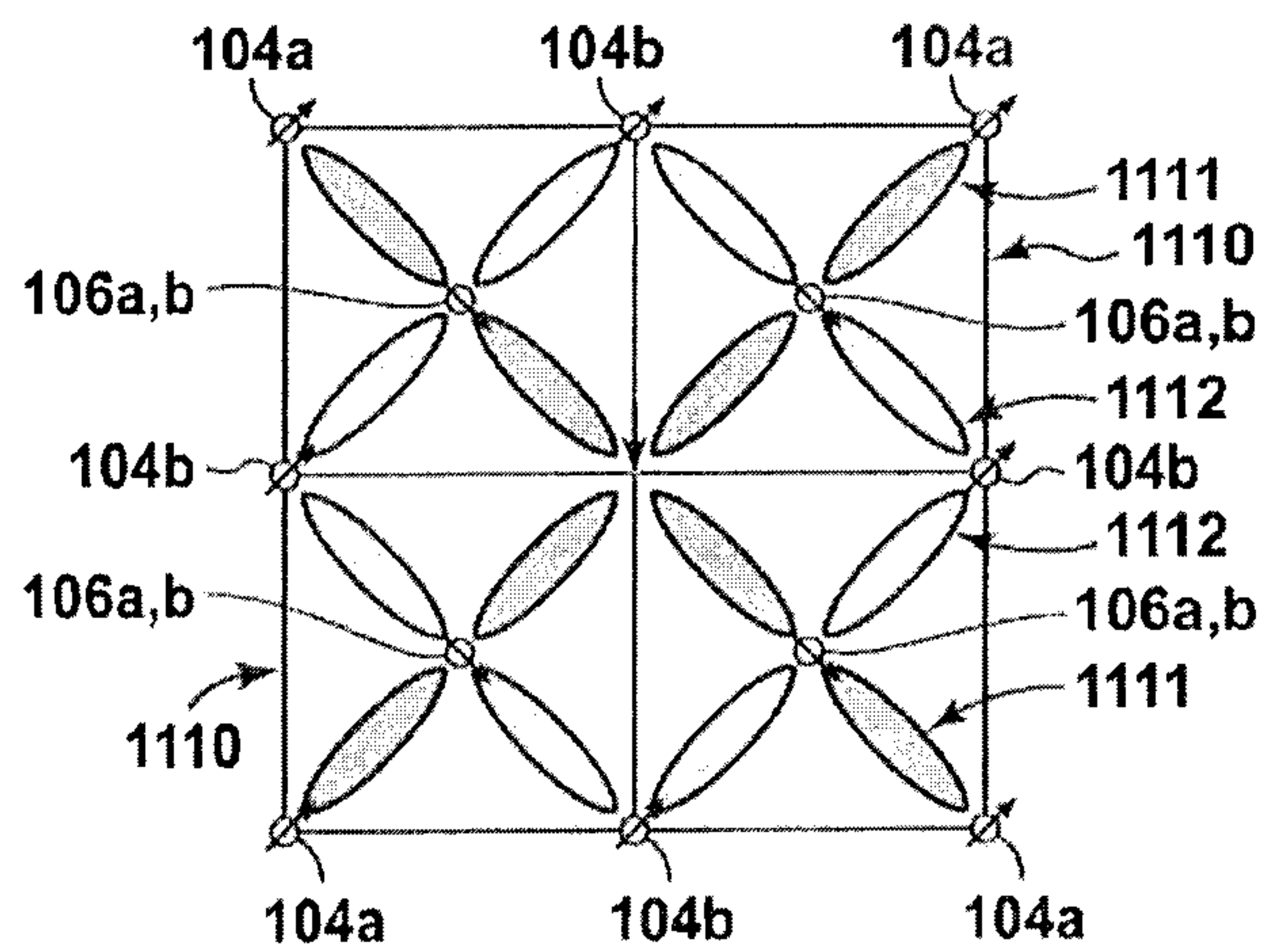
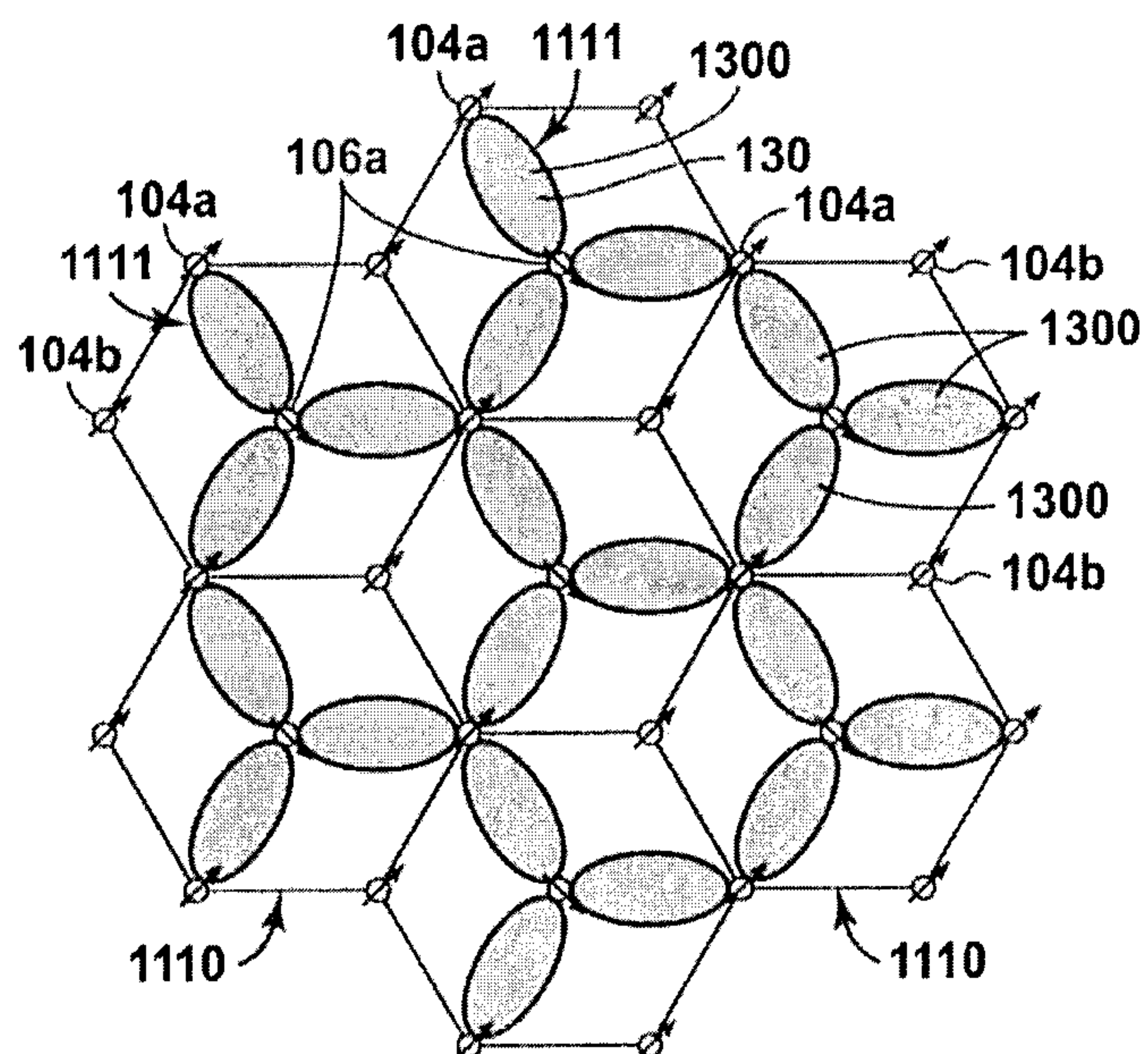
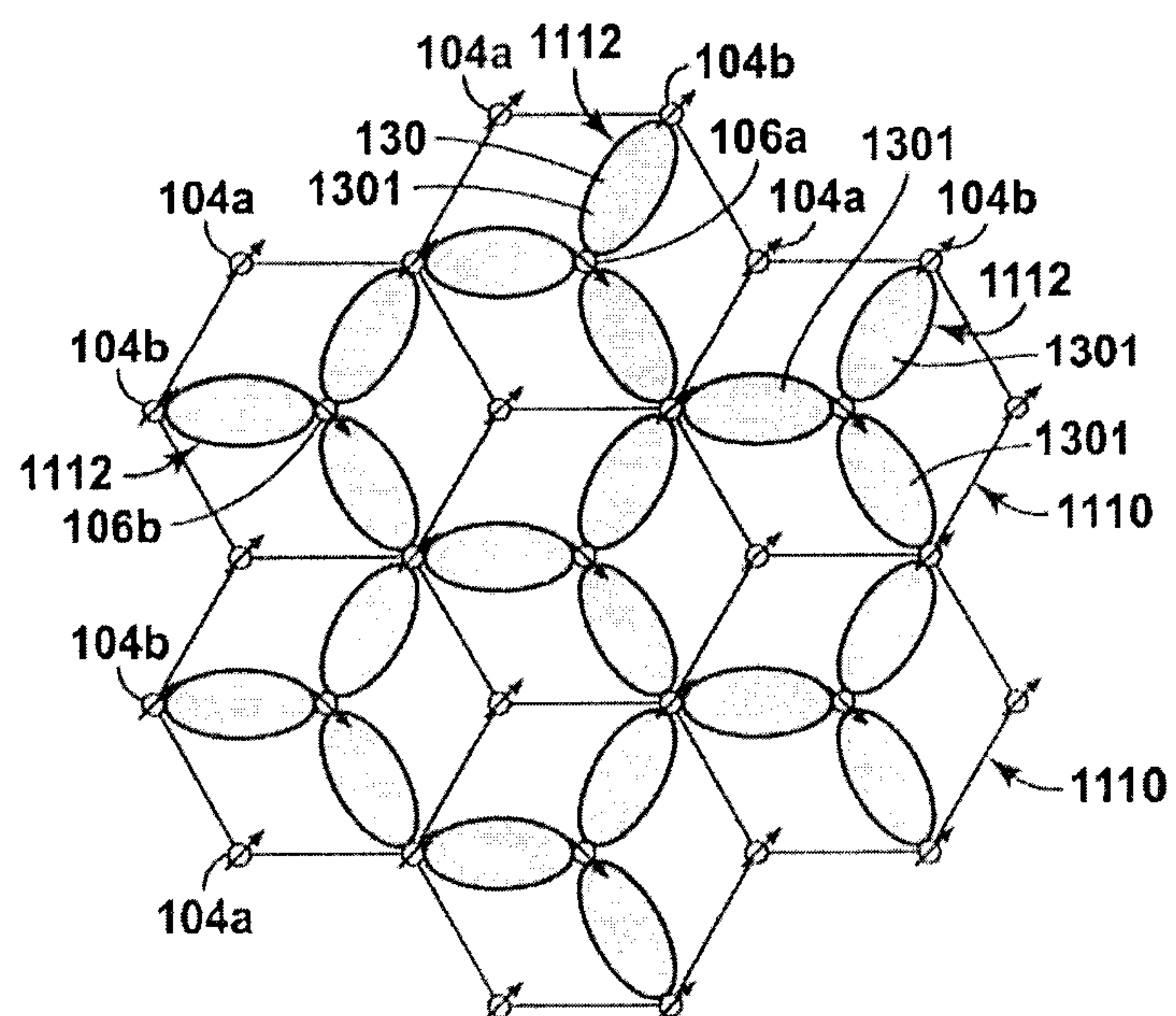
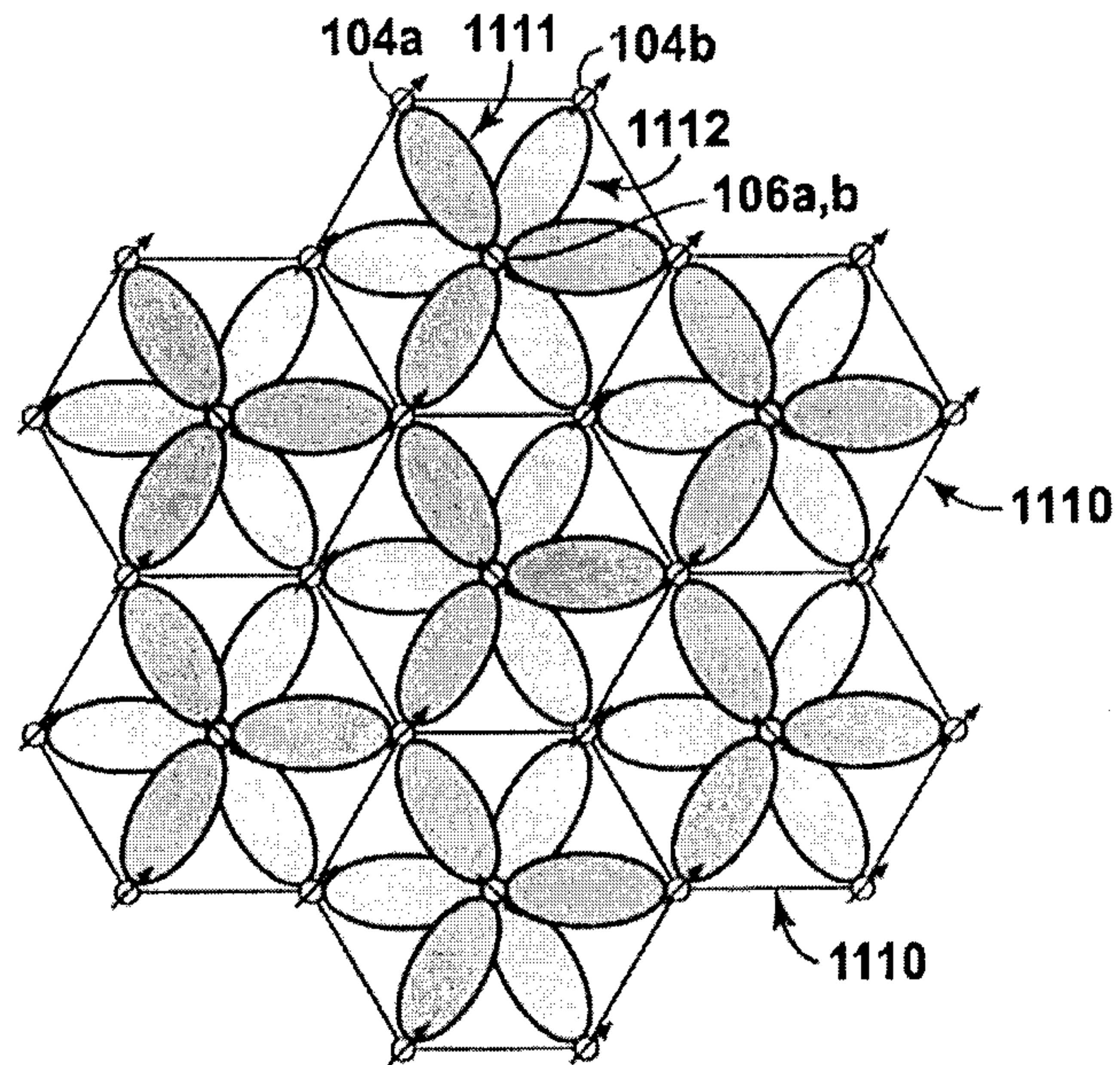


FIG. 2C

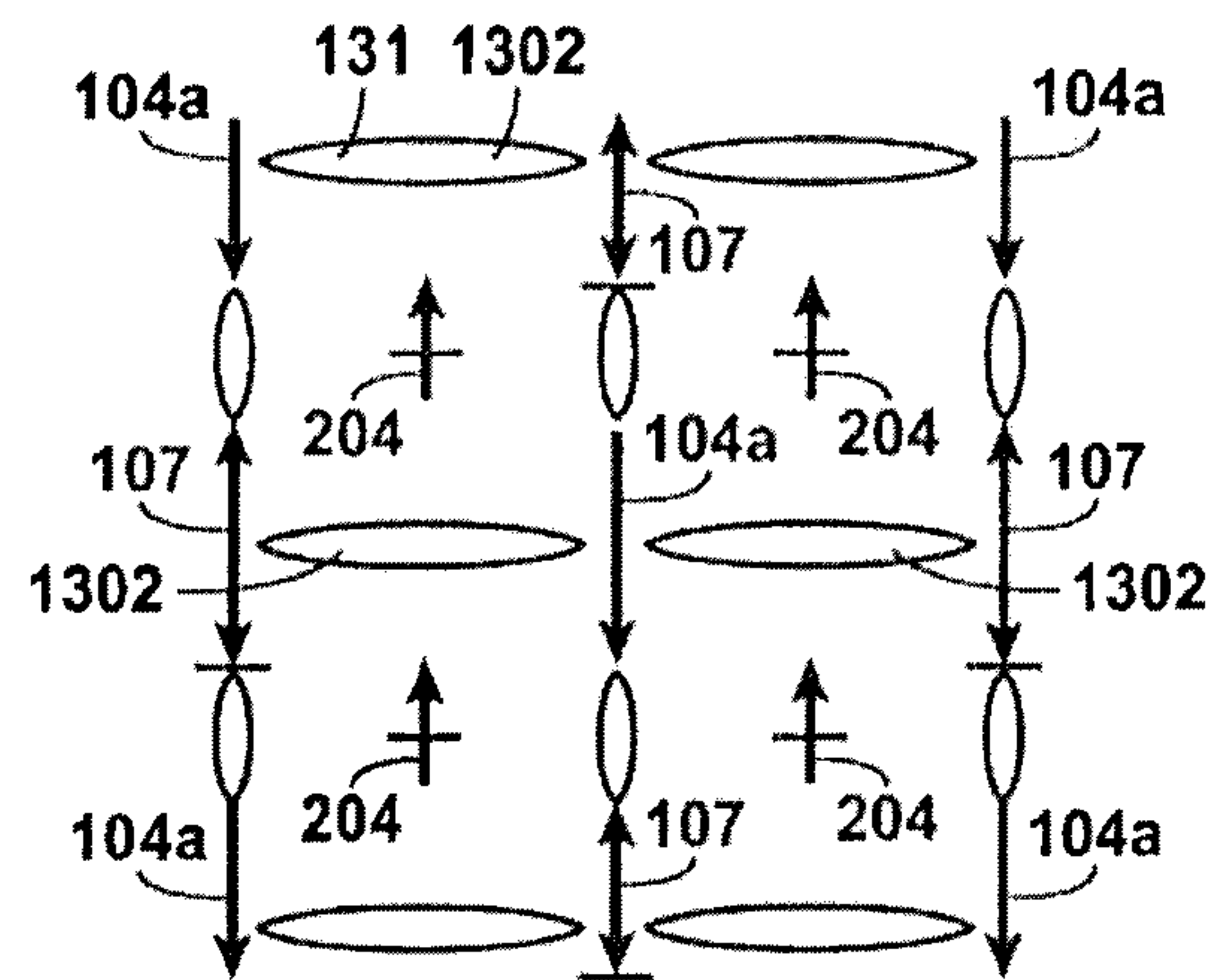
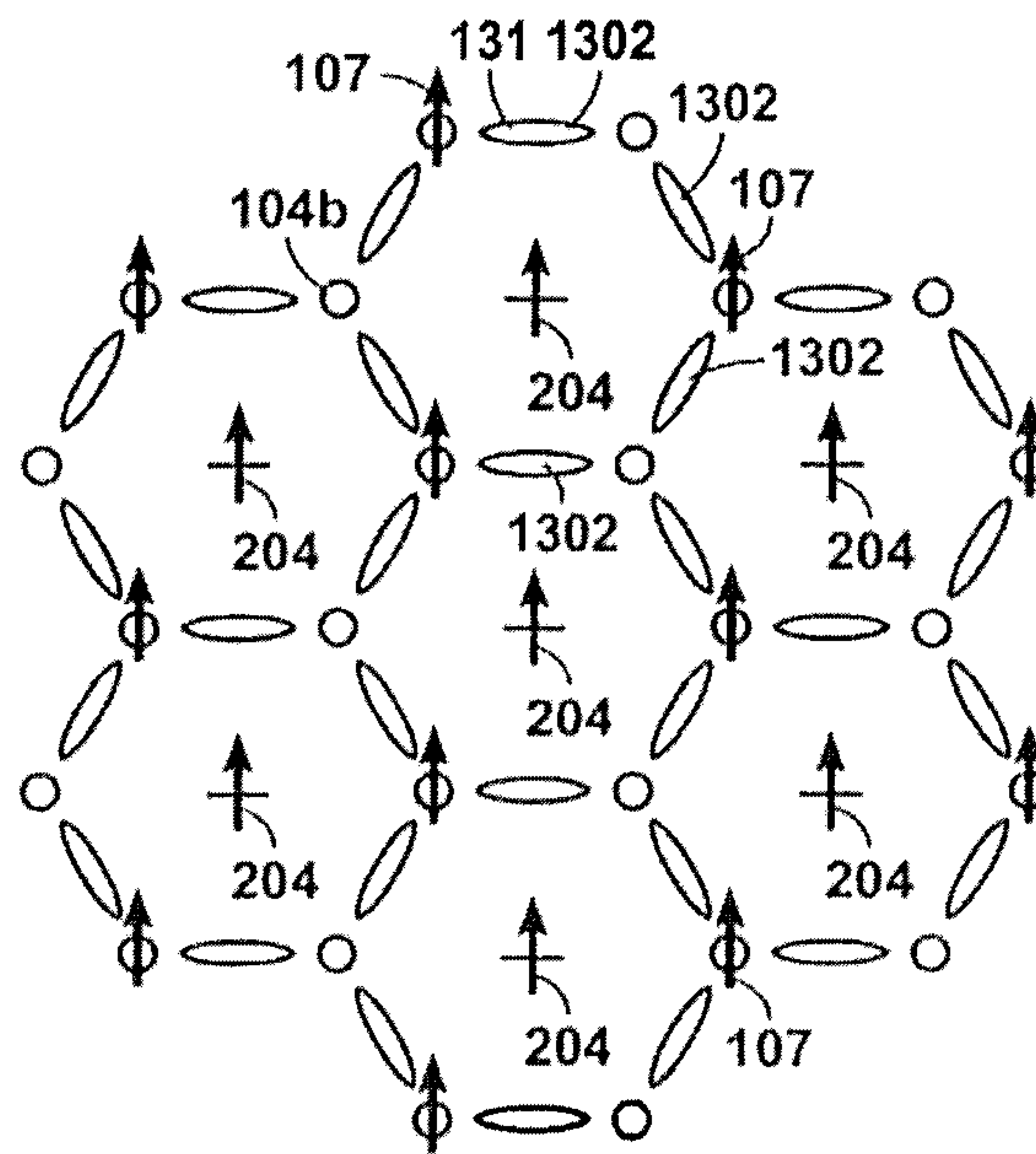
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**FIG. 3A****FIG. 3B**

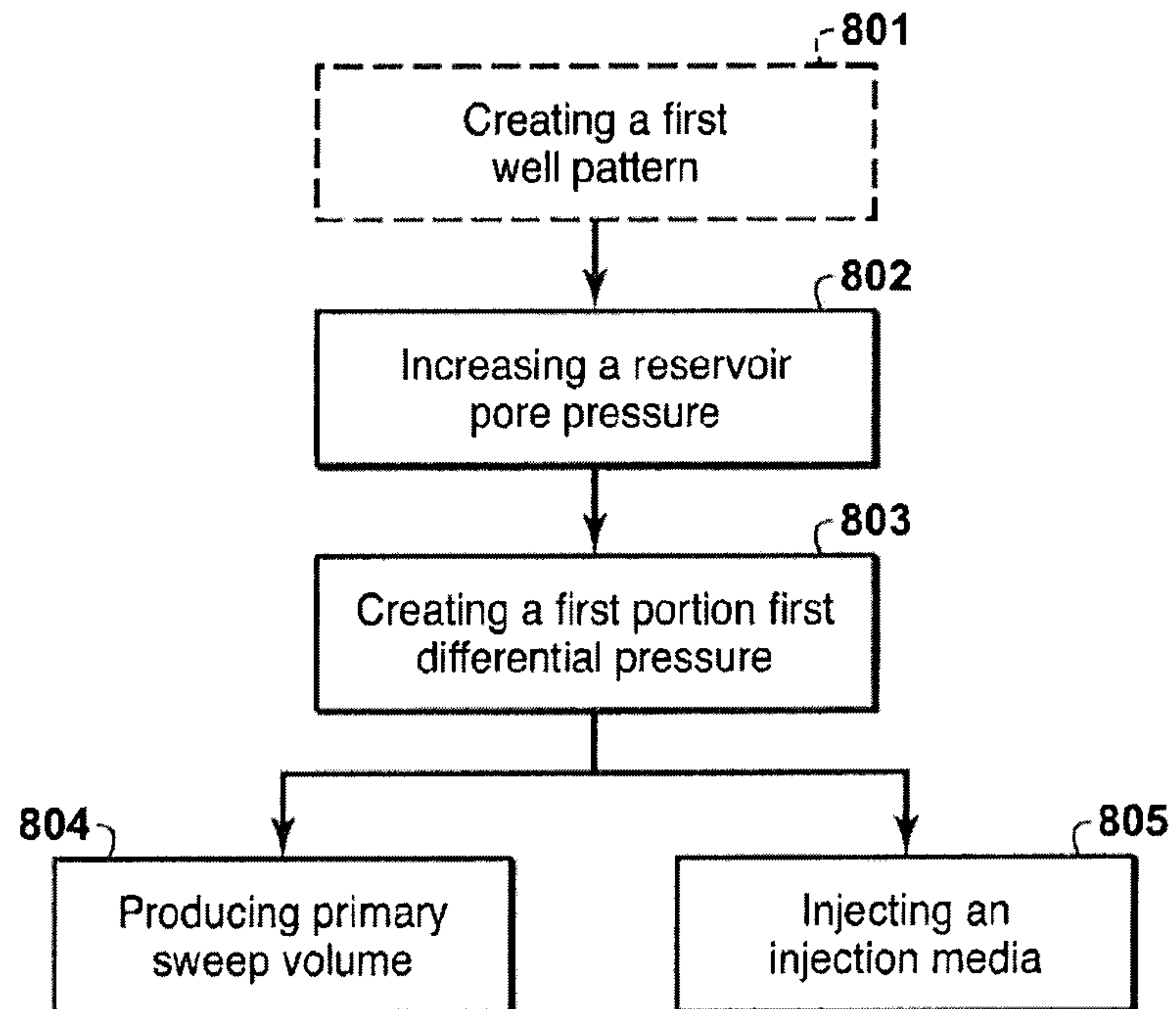
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**FIG. 3C**

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**FIG. 4****FIG. 5**

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**FIG. 6**

