



(22) Date de dépôt/Filing Date: 2011/01/28

(41) Mise à la disp. pub./Open to Public Insp.: 2011/07/29

(45) Date de délivrance/Issue Date: 2016/03/29

(30) Priorité/Priority: 2010/01/29 (US61/299,696)

(51) Cl.Int./Int.Cl. *E21B 43/00* (2006.01),
E21B 43/22 (2006.01), *E21B 43/24* (2006.01)

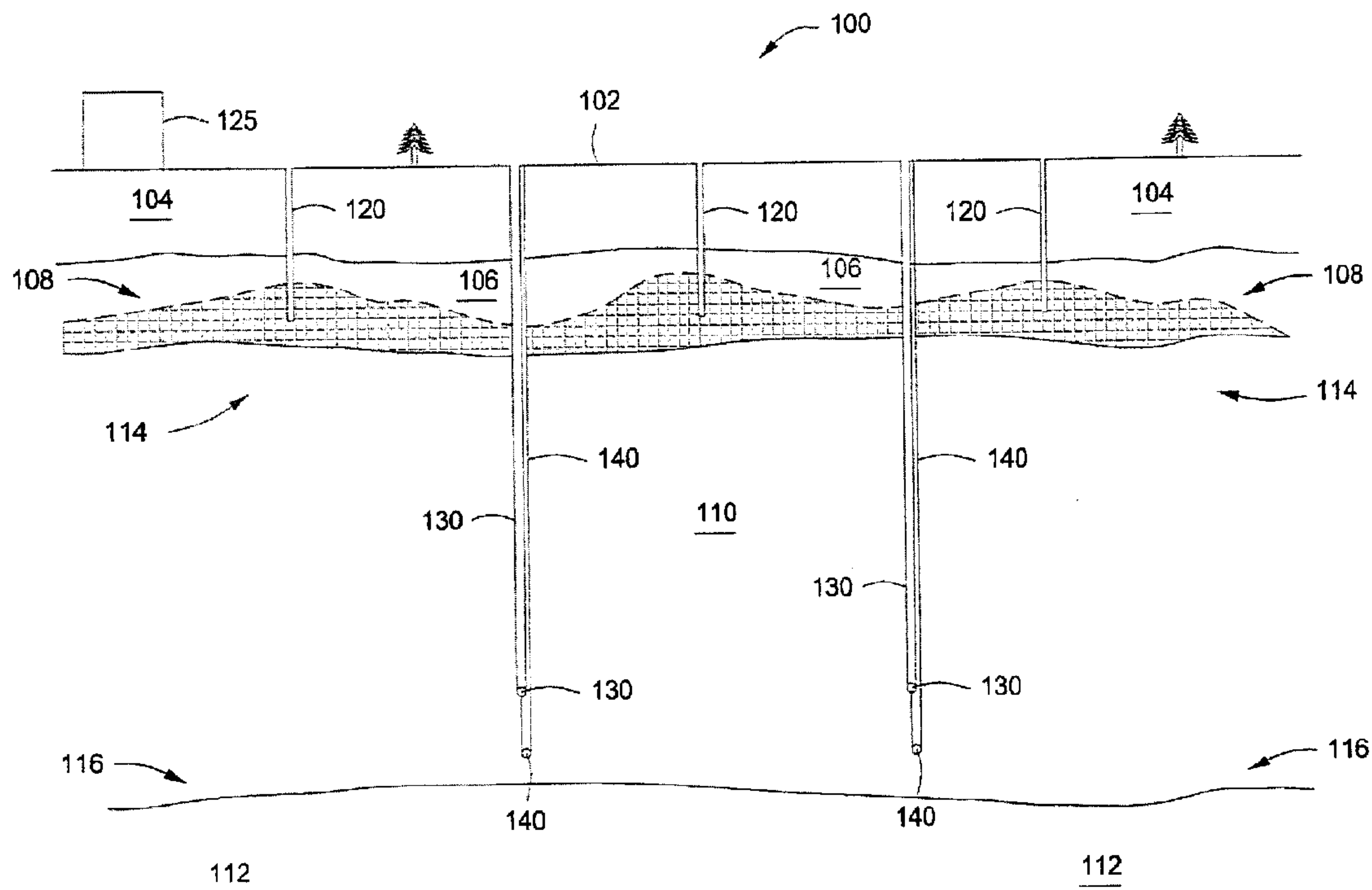
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(54) Titre : RECUPERATION D'HYDROCARBURES AU MOYEN DE BARRIERES ARTIFICIELLES

(54) Title: RECOVERY OF HYDROCARBONS USING ARTIFICIAL TOPSEALS



(57) Abrégé/Abstract:

A method is described for recovering viscous oil such as bitumen from a subsurface formation. The method involves creating an artificial barrier in a subterranean zone above or proximate a top of the subsurface formation. The barrier is largely impermeable to fluid flow. The method also includes reducing the viscosity of the viscous oil and mobilizing hydrocarbons into a readily flowable heavy oil by addition of heat and/or solvent. Heating preferably uses a plurality of heat injection wells. The method further includes producing the heavy oil using a production method that preserves the integrity of the artificial barrier.

ABSTRACT

A method is described for recovering viscous oil such as bitumen from a subsurface formation. The method involves creating an artificial barrier in a subterranean zone above or proximate a top of the subsurface formation. The barrier is largely impermeable to fluid flow. The method also includes reducing the viscosity of the viscous oil and mobilizing hydrocarbons into a readily flowable heavy oil by addition of heat and/or solvent. Heating preferably uses a plurality of heat injection wells. The method further includes producing the heavy oil using a production method that preserves the integrity of the artificial barrier.

RECOVERY OF HYDROCARBONS USING ARTIFICIAL TOPSEALS

The present invention relates to the field of hydrocarbon recovery from subsurface formations. More specifically, the present invention relates to the *in situ* recovery of hydrocarbon fluids from viscous oil formations including, for example, oil sands formations containing bitumen. The present invention also relates to methods for sealing a formation to prevent the upward migration of an injected heating vapor and/or solvent.

This section is intended to introduce various aspects of the art, which may be associated with exemplary embodiments of 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.

For many years, oil companies have explored for and produced hydrocarbons. While the term "hydrocarbons" generally refers to any organic material with molecular structures containing carbon bonded to hydrogen, hydrocarbons have primarily been produced from subsurface formations where the hydrocarbon is in a fluid form. In a liquid state, such hydrocarbons are commonly referred to as "oil," while in a gas state such hydrocarbons are known as "natural gas."

In the last 25 years, energy companies have investigated the production of hydrocarbons that reside in a highly viscous or even solid (non-fluid) form. Such hydrocarbons may generally be referred to as "heavy hydrocarbons" and "solid hydrocarbons," respectively.

"Solid hydrocarbons" refers to any hydrocarbon material that is found naturally in substantially solid form at formation conditions. Examples include kerogen, coal, shungites, asphaltites, and natural mineral waxes. Heavy hydrocarbons include hydrocarbons that are highly viscous at ambient conditions (15° – 25° C and 1 atm pressure). These include bitumen, asphalt, and so-called heavy oil.

The viscosity of heavy hydrocarbons is generally greater than about 100 centipoise at 15° C. Bitumen and heavy oil are sometimes together referred to as viscous oils. Heavy

hydrocarbons may also be classified by API gravity, and generally have an API gravity below about 20 degrees. Heavy oil, for example, generally has an API gravity of about 10 to 20 degrees, whereas tar generally has an API gravity below about 10 degrees.

The terms "bitumen" and "tar" are sometimes used interchangeably. Both materials are highly viscous, black, and sticky substances. However, the naturally occurring tar in subsurface formations is technically bitumen. Bitumen is a non-crystalline, highly viscous hydrocarbon material that is substantially soluble in carbon disulfide. Bitumen includes highly condensed polycyclic aromatic hydrocarbons, and is commonly used for paving roads.

Viscous oil deposits are located in various regions of the world. For example, viscous oils have been found in abundance in the Milne Point Field on the North Slope of Alaska. Viscous hydrocarbons also exist in the Jobo region of Venezuela, and have been found in the Edna and Sisquoc regions in California. In addition, extensive formations of oil sands exist in northern Alberta, Canada. These formations are sometimes referred to as "tar sands," though they technically contain bitumen.

The Athabasca oil sands deposit in northern Alberta is one of the largest viscous oil deposits in the world. There are also sizable oil sands deposits on Melville Island in the Canadian Arctic, and two smaller deposits in northern Alberta near Cold Lake and Peace River. The oil sands contain substantial amounts of bitumen.

There are two methods currently used to extract bitumen from the ground. These are an open pit mining process, and an *in situ* recovery process. In either instance, once extracted, oil sands producers typically maintain the hydrocarbon material in a heated condition and/or add lighter hydrocarbons to the bitumen to allow it to flow through pipelines. Upgraders then process the bitumen into synthetic crude.

Open pit mining resembles conventional mining techniques, and is effective in extracting oil sands deposits if the deposits are sufficiently tar-like. Mining of bitumen deposits is a well-established technology. However, bitumen mining has several drawbacks. First open pit mining is generally limited to oil sands deposits that are near the surface. Generally, production is limited to formations that are less than about 80 meters in depth due to the cost of overburden removal. In addition, there are high capital and maintenance costs associated with solids-handling equipment. Further, open pit mining may require high water usage for separating the bitumen from the sand. Finally, open pit

mining creates a substantial disruption of the surface for years during recovery operations and until restoration activities are performed.

The bulk of Canada's oil sands deposits are too deep below the surface to use open pit mining. However, the *in situ* recovery method may reach the deeper deposits. *In situ* extraction often involves the use of a heated fluid to separate bitumen from the sands at a selected depth, and permit the heated bitumen to flow through wells to the surface. The heated fluid may be steam. Alternatively, the heated fluid may be a solvent vapor or a steam-solvent mixture. In some processes, unheated solvent is used in a liquid or vapor state.

Several steam injection processes have been suggested for heating bitumen. One general method for recovering viscous hydrocarbons is by using a "steam stimulation" technique known as the "huff-and-puff" process. In the huff-and-puff process, steam is injected into a formation by means of one or more wells. The wells are then shut-in to permit the steam to heat the bitumen, thereby reducing its viscosity. Subsequently, all formation fluids, including mobilized bitumen and at least partially condensed steam, are produced together from the well using accumulated reservoir pressure as the driving force for production.

Initially in the huff-and-puff process, sufficient pressure may be available in the vicinity of the wellbores to lift fluids to the surface. As the pressure falls, artificial lifting methods are normally employed. Production is terminated when artificial lift is no longer effective. Steam is then injected again. This cycle may take place many times until oil production is no longer economical.

In the huff-and-puff method, the highest pressures and temperatures exist in the vicinity of the well immediately following the injection phase. Normally this pressure and temperature will correspond to the properties of the steam which was employed. Before oil can be moved from the remote parts of the reservoir to the well, the pressure in the near well region must fall so that it is lower than the distant reservoir pressure. During this initial depressuring phase, the near-wellbore reservoir material cools down as water flashes into steam. The first production from the well thus tends to be steam, and this tends to be followed by hot water. Eventually, the pressure is low enough that oil can move to the wellbore.

In the initial production phase, much of the heat which was put into the reservoir with the steam is simply removed again as steam and hot water. A major inefficiency of

the huff and puff process is that this heat must be supplied during each cycle. As the available oil becomes more remote from the well, this cyclic wasted heat quantity increases, meaning that more hot water but less mobilized bitumen is produced.

U.S. Pat. No. 4,344,485, entitled "Method for Continuously Producing Viscous Hydrocarbons by Gravity Drainage While Injecting Heated Fluids," presented an improved steam injection technique. This technique is known as steam-assisted gravity drainage, or SAGD. This is a low pressure *in situ* application.

In SAGD, an injection well is completed for injecting a heated fluid such as steam. A production well for producing oil and condensate is also drilled into the formation adjacent to the injection well. The wells are also completed such that separate oil and water flowpaths in at least the near-wellbore region of the production well are ensured with appropriately throttled injection and production rates. Variants of SAGD exist in which solvent is added to the steam (see U.S. Pat. No. 6,662,872) or solvent completely replaces the steam (see U.S. Pat. No. 5,407,009 and U.S. Pat. No. 6,883,607).

Initially, the formation may be fractured by injecting the heated fluid via the injection well at a higher-than-fracture pressure. Alternatively, a suitable fracturing fluid may be used to create fractures. Alternatively still, no fracturing is performed and fluid communication between the wells is established simply by heating.

Next, steam is injected via the injection well to heat the formation. As the steam condenses and gives up its heat to the formation, the viscous hydrocarbons are mobilized. The hydrocarbons then drain by gravity toward the production well. Mobilized viscous hydrocarbons are able to be recovered continuously through the production well.

In one embodiment, two nearly horizontal wells are formed, with one well being located directly above the other. In this arrangement, the upper well is used to inject steam and then remove water and condensate, while the lower well is used to continuously produce the mobilized viscous oil. In another embodiment, two vertical wells are provided, with one well being the steam injection / water production well, and the other being a hydrocarbon production well. In yet a third embodiment, a horizontal well is drilled and extended below a vertical steam injection well. Steam is injected into the formation, causing the mobilization of heavy oil. Oil is then produced through the elongated horizontal well.

A requirement of SAGD and other *in situ* bitumen recovery methods is the need for a largely impermeable topseal. A topseal is an impermeable geological barrier

provided in a more shallow formation. The topseal serves to contain injected fluids and/or gases that are released or created during heating and production. These released gases may include greenhouse gases such as methane or carbon dioxide. Moreover, the injected fluids contain heat which would reduce process efficiency if lost to an overburden region.

Many shallow bitumen deposits have tops that are geologic unconformities such as eroded zones. Such zones are not effective topseals as they are relatively permeable to fluid flow. Lack of a topseal typically prevents economic recovery of mobilized heavy hydrocarbon deposits since any injectant (*e.g.*, steam) readily channels into the permeable overburden and is lost to non-productive areas. In some cases, the injectant will leak all the way to the surface. In either instance, the injectant does not effectively penetrate the viscous oil material.

Therefore, there is a need for new methods for recovering viscous oil from subterranean deposits lacking effective topseals.

The methods described herein have various benefits in the conducting of oil and gas exploration and production activities in formations having oil sands or other viscous oil deposits.

First, a method is provided for recovering a viscous hydrocarbon from a subsurface formation. In one embodiment, the method includes creating an artificial barrier in a subterranean zone. The subterranean zone is above or proximate a top of the subsurface formation. Preferably, the artificial barrier is formed within 5 meters of the top of the subsurface formation. The artificial barrier is largely impermeable to fluid flow.

The artificial barrier may be formed by injecting a polymer solution into the subterranean zone. The polymer solution chemically reacts *in situ* to form a gel. Preferably, the polymer solution is injected into the subterranean zone at a pressure below the fracture pressure. Alternatively, a fluid may be injected into the subterranean zone above the fracture pressure so to form horizontal fractures only and fill the fractures with a barrier-forming substance. The artificial barrier may alternatively be formed by injecting a waxy emulsion, a clay slurry, or molten sulfur, or by jetting in a grout material.

In another arrangement, the step of creating an artificial barrier may involve completing a plurality of refrigerator wells in the subterranean zone. In this instance, a cooling fluid is circulated through each of the plurality of refrigerator wells. Circulation of the cooling fluid causes water in the subterranean zone to convert to ice *in situ*. Thus, a frozen horizontal barrier is formed.

The method also includes reducing the viscosity of the viscous hydrocarbon, and mobilizing the viscous hydrocarbon into a readily flowable heavy oil. In a preferred embodiment, this is accomplished by use of heat applied to the subsurface formation. Heating the formation has the effect of reducing the viscosity of the viscous hydrocarbon, and mobilizing the viscous hydrocarbon into a readily flowable heavy oil. In one aspect, heating involves the creation of a plurality of heat-supplying wells. Each of the heat-supplying wells may carry an electric current. In this instance, heating the subsurface formation comprises applying electrical-resistive heat to the subsurface formation to reduce the viscosity of the viscous hydrocarbon. In another aspect, each of the heat-supplying wells is a heat injection well. In this instance, heating the subsurface formation comprises injecting a heated, vaporized fluid as an injectant through each of the injection wells. The injectant may be, for example, steam, a hydrocarbon solvent, or combinations thereof. In some embodiments, a hydrocarbon solvent may be injected in an unheated stated.

The method further includes producing the heavy oil to the surface. The production process uses a low-pressure production method. An example is a gravity drainage method that provides for essentially continuous production. The production method is compatible with the artificial barrier, meaning that the production method does not compromise the integrity of the topseal.

The viscous hydrocarbon may have a viscosity greater than about 100 centipoise in its undisturbed *in situ* state. In one aspect, the viscous hydrocarbon comprises primarily bitumen.

An alternative method for recovering viscous hydrocarbons from a subsurface formation is provided herein. This method may first comprise locating a permeable subterranean zone geologically above the subsurface formation. A gelling fluid is then injected into the subterranean zone in a liquid phase. After a time, the gelling fluid will gel, forming an artificial topseal over the subsurface formation.

In one aspect, the gelling fluid is a polymer solution that undergoes a chemical reaction within the subterranean zone to slowly form the gel. In another aspect, the gelling fluid is a temperature-sensitive, waxy, oil-external emulsion comprising oil, added wax, and water. The waxy emulsion is formulated to be substantially a solid at initial *in situ* temperature conditions and *in situ* pressures in the subterranean zone. In order to inject the gelling fluid, the method further comprises heating the waxy, oil-external emulsion

into a flowable liquid at a surface heater before injecting the emulsion into the permeable subterranean zone. The emulsion will form the gel as it cools in the subterranean zone. In another aspect, the injected fluid chemically reacts *in situ* to form a solid precipitate which leads to pore plugging and permeability reduction of the formation rock.

The method also includes forming a plurality of heat injection wells into the subsurface formation, and also forming a plurality of producer wells into the subsurface formation. Each injector well has one or more associated producer wells, thereby creating sets of wells for the recovery operation. In one aspect, each of the heat injection wells is completed horizontally within the subsurface formation. In another aspect, each of the producer wells is completed horizontally within the subsurface formation. In one embodiment, each of the heat injection wells is completed horizontally within the subsurface formation and each of the producer wells is completed horizontally within the subsurface formation, such that each of the sets of wells is a pair of wells, and each of the pairs of wells is completed substantially within a vertical plane.

The method further includes injecting steam into each of the plurality of heat injection wells. Injecting steam serves to heat the subsurface formation. The heat (i) creates steam chambers within the subsurface formation, (ii) reduces the viscosity of the viscous hydrocarbons, and (iii) mobilizes the viscous hydrocarbons into a flowable heavy oil. In one aspect, the step of injecting steam into each of the plurality of heat injection wells is ceased before the steam chamber reaches the artificial topseal. A preserved viscous hydrocarbon layer at the top of the subsurface formation serves to enhance the effectiveness of the artificial topseal. Alternatively, the composition of steam is modified to include a hydrocarbon solvent, with the temperature of the injectant being reduced before the steam chamber compromises the effectiveness of the topseal.

The method also comprises producing the heavy oil through each of the plurality of producer wells.

BRIEF DESCRIPTION OF THE DRAWINGS

So that the present inventions can be better understood, certain illustrations and flow charts are appended hereto. It is to be noted, however, that the drawings illustrate only selected embodiments of the inventions and are therefore not to be considered limiting of scope, for the inventions may admit to other equally effective embodiments and applications.

Figures 1A through 1F present cross-sectional views of subsurface strata in an oil field. The strata include a subsurface formation having a viscous oil. A substantially horizontal barrier has been placed as a topseal over the subsurface formation.

In Figure 1A, heat injection wells and production wells have been completed in the subsurface formation. No heating has yet taken place in the subsurface formation.

In Figure 1B, steam or other heated vapor is being injected into the subsurface formation through the heat injection wells. Small but growing steam chambers are seen around the heat injection wells.

In Figure 1C, heated vapor continues to be injected into the subsurface formation. The steam chambers have enlarged around the heat injection wells. In addition oil drainage layers have formed where viscous oil flows under low pressure towards the production wells.

In Figure 1D, heated vapor continues to be injected into the subsurface formation. The steam chambers have approached the topseal. The oil drainage layers have reached the top of the subsurface formation.

In Figure 1E, the steam chambers have merged to form a single steam chamber. The topseal allows viscous oil to be mobilized to the top of the subsurface formation while substantially preventing heated vapor from migrating into the subterranean zone. Heated solvent is optionally injected into the subsurface formation to avoid the encroachment of high-temperature steam into the topseal. This provides for the mobilization of additional viscous hydrocarbons without compromising the topseal.

In Figure 1F, the steam chambers have expanded away from the heat injection wells to substantially fill the subsurface formation. An oil drainage layer continues to advance ahead of the heated vapor.

Figures 2A and 2B provide cross-sectional views of cooling wells as may be used to freeze native waters, in alternate embodiments.

Figure 2A shows a cooling well where a cooling fluid is injected down the bore of a working string, passed through a single expander valve, and circulated back to the surface through an annulus.

Figure 2B shows a cooling well where a cooling fluid is injected down the bore of a working string, passed through two separate expander valves in the bore, and circulated back to the surface through the annulus.

Figure 3 is a flowchart showing steps that may be taken to set a waxy emulsion in a subterranean zone to form an artificial barrier.

Figure 4 is a cross-sectional view of a pair of wells, representing a heat injection well and a production well, in one embodiment. The heat injection well is used to decrease the viscosity of bitumen or other viscous hydrocarbon in a hydrocarbon formation.

Figure 5 is a flowchart showing steps for a method of recovering a viscous hydrocarbon from a subsurface formation. The method includes creating an artificial barrier in a subterranean zone above or proximate a top of the subsurface formation, and heating the subsurface formation in order to reduce the viscosity of the viscous hydrocarbon.

Figure 6 is a flowchart showing steps for a method for recovering viscous hydrocarbons from a subsurface formation, in an alternate embodiment. The method includes injecting a polymer solution into the subterranean zone in a liquid phase, and allowing time for the polymer solution to gel within the subterranean zone and form an artificial topseal over the subsurface formation.

As used herein, the term “hydrocarbon” refers to an organic compound that includes primarily, if not exclusively, the elements hydrogen and carbon. Hydrocarbons may also include other elements, such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur. Hydrocarbons generally fall into two classes: aliphatic, or straight chain hydrocarbons, and cyclic, or closed ring hydrocarbons, including cyclic terpenes. Examples of hydrocarbon-containing materials include any form of natural gas, oil, coal, and bitumen.

As used herein, the term “hydrocarbon fluids” refers to a hydrocarbon or mixtures of hydrocarbons that are gases or liquids. For example, hydrocarbon fluids may include a hydrocarbon or mixtures of hydrocarbons that are gases or liquids at formation conditions, at processing conditions or at ambient conditions (15° C and 1 atm pressure). Hydrocarbon fluids may include, for example, oil, natural gas, coalbed methane, shale oil, pyrolysis oil, pyrolysis gas, a pyrolysis product of coal, and other hydrocarbons that are in a gaseous or liquid state.

The term “viscous hydrocarbon” refers to a hydrocarbon material residing in a subsurface formation that is in a generally non-flowable condition. Viscous hydrocarbons

have a viscosity that is generally greater than about 100 centipoise at 15° C. A non-limiting example is bitumen.

As used herein, the term “heavy oil” refers to relatively high viscosity and high density hydrocarbons, such as bitumen. Gas-free heavy oil generally has a viscosity of greater than 100 centipoise and a density of less than 20 degrees API gravity (greater than about 900 kilograms /cubic meter). Heavy oil may include carbon and hydrogen, as well as smaller concentrations of sulfur, oxygen, and nitrogen. Heavy oil may also include aromatics or other complex ring hydrocarbons.

As used herein, the term "subsurface" refers to geologic strata occurring below the earth's surface.

The terms “zone” or “subterranean zone” refer to a selected portion of a formation. The formation may or may not contain hydrocarbons or formation water.

As used herein, the term “subsurface formation” means any definable subsurface region. The formation may contain one or more hydrocarbon-containing layers, one or more non-hydrocarbon containing layers, an overburden, and/or an underburden of any geologic formation. An “overburden” and/or an “underburden” is geological material above or below the formation of interest. An overburden or underburden may include one or more different types of substantially impermeable materials. For example, overburden and/or underburden may include rock, shale, mudstone, or wet/tight carbonate (i.e., an impermeable carbonate without hydrocarbons). In some cases, the overburden and/or underburden may be permeable.

As used herein, the terms “produced fluids” and “production fluids” refer to liquids and/or gases removed from a subsurface formation, including, for example, an organic-rich rock formation. Produced fluids may include both hydrocarbon fluids and non-hydrocarbon fluids. Production fluids may include, but are not limited to, pyrolyzed shale oil, synthesis gas, a pyrolysis product of coal, carbon dioxide, hydrogen sulfide and water (including steam).

As used herein, the term “fluid” refers to gases, liquids, and combinations of gases and liquids, as well as to combinations of gases and solids, and combinations of liquids and solids.

As used herein, the term “gas” refers to a fluid that is in its vapor phase at 1 atm and 15° C.

As used herein, the term "oil" refers to a hydrocarbon fluid containing primarily a mixture of condensable hydrocarbons.

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

The term "tubular member" refers to any pipe, such as a joint of casing, a portion of a liner, or a pup joint.

As used herein, the term "oil-external emulsion" refers to any emulsion where oil is the continuous phase.

The term "wax" refers to any one of various substances that is substantially hydrophobic, that is, insoluble in water, and that has a relatively low viscosity when melted. The wax may be, for example, a petroleum-derived wax such as a paraffin. The wax may alternatively be a non-petroleum natural wax such as, for example, beeswax or vegetable wax. One non-limiting example of a wax is Imperial Oil Wax 1010. Wax may be present in oil naturally or may be added, in which case it is referred to as "added wax."

The term "emulsifying agent" refers to any substance that assists in the formation and stabilization of emulsions. Non-limiting examples of emulsifying agents include surfactants (both ionic and non-ionic), fine mineral solids (such as fumed silica and bentonite), and any pH modifying agent (including, but not limited to metal hydroxides).

The term "solvent" refers to any fluid that is significantly soluble with a particular liquid, resulting in a homogeneous mixture at the temperature and pressure of interest. Solubility amounts of the solvent in the liquid resulting in a homogeneous mixture may be greater than 10 mass percent. Non-limiting examples of solvents for hydrocarbon oils include propane, heptane, diesel, and kerosene.

The term "gel strength" refers to the shear stress required to cause a fluid to initiate flow. An indicator of gel strength is the maximum pressure gradient that may be applied to a fluid before flow occurs through an area plugged with the gel.

Methods are provided herein for recovering a viscous hydrocarbon from a subsurface formation. The methods are intended to create an extended artificial topseal near or just above the top of the subsurface formation. The topseal may be greater than one acre or, more preferably, greater than about five acres (20,232 m²). Alternatively and

more preferably, the topseal is substantially continuous over an area that is at least about ten acres (40,464 m²).

Once in place, the topseal allows for the recovery of hydrocarbons from oil sands or so-called "tar sands" without need of surface mining or open pit mining. In this respect, the subsurface formation may be effectively heated using an injectant such as steam or a hydrocarbon vapor with minimal to no loss of the heated injectant. The methods herein may be employed even for viscous oil deposits that could otherwise be recovered through open pit mining. This preserves the surface and reduces capital costs.

Figure 1A presents a cross-sectional view of subsurface strata in an oil field 100 under development. The oil field 100 targets a subsurface formation 110 containing viscous hydrocarbons such as bitumen. The viscous hydrocarbons are in an unheated and immobile state. However, it is desired to recover the viscous hydrocarbons from the subsurface formation 110 without disrupting the surface 102 of the oil field 100.

In Figure 1A, it can be seen that the oil field 100 contains near-surface strata 104 above the subsurface formation 110. Between the formation 110 of interest and the near-surface strata 104 is a subterranean zone 106. Below the formation 110 is an underburden 112.

The underburden 112 is typically largely impermeable to fluid flow. However, the subterranean zone 106 is comprised of sand, or a mixture of sand and soil, and is highly permeable. The subterranean zone 106 may geologically be a part of the same formation as near-surface strata 104. In any instance, the highly permeable nature of the subterranean zone 106 prevents the effective use of an injectant as part of an *in situ* recovery process.

In accordance with the methods herein, an artificial barrier may be created in the subterranean zone 106. An artificial barrier is shown at 108 extending across the top of the subsurface formation 110. The artificial barrier 108 serves as a topseal, and once created is largely impermeable to fluid flow. The artificial barrier 108 allows for the use of an injectant for an *in situ* recovery process within the subsurface formation 110. The artificial barrier may be several feet in thickness on average but may be much thinner, for example less than 1 foot or even less than about 1 inch (2.54 cm).

In order to place the artificial barrier 108 in the subterranean zone 106, various service wells 120 have been formed. In Figure 1A, the service wells 120 are shown as

completed vertically. However, in some operations it may be preferred to complete the service wells 120 horizontally along the subterranean zone.

Depending on the nature of the artificial barrier 108, the wells may serve different purposes. In one aspect, the artificial barrier 108 is formed using service wells 120 by injection of an injectable mixture such as a polymer solution, which flows through the permeable zone and which gels *in situ*. Alternatively, the injectable mixture may be molten sulfur (see, for example, U.S. Pat. No. 7,631,689), or may be grout such as sulfur cement, Portland cement, or clay which is injected into the formation 110 as a slurry. In this instance, the molten sulfur, cement, or grout is injected into the subterranean zone 106 under pressure to plug the pores and vugs in the permeable subterranean zone 106. In some embodiments, the injectable mixture is dispersed above the subsurface formation 110 through interconnecting horizontal fractures.

The subterranean zone 106 may be shallow, for example less than 300 feet in depth. Because of a shallow nature of the subterranean zone 106, the injectable mixture may be injected at a pressure that exceeds the formation fracture pressure of the strata 104, 106. In this instance, the fractures will primarily be horizontal in nature. It can be seen from Figure 1A that the injectable mixture has spread substantially horizontally over and across the subsurface formation 110 to create a continuous topseal.

In another arrangement, the service wells 120 comprise a plurality of refrigerator wells. In this instance, a cooling fluid is circulated through each of the plurality of refrigerator wells 120. The cooling fluid may be a chilled liquid, a vaporizing refrigerant, or a partially frozen slurry. In one aspect, the cooling fluid may be a brine, glycol-water solution, or alcohol-water solution. In another aspect, the cooling fluid is comprised at least of 50 mol. percent of propane, propylene, ethane, ethylene, or a mixture thereof. In this arrangement, the service wells 120 will preferably have a substantial horizontal portion (not shown in Figure 1A). The horizontal portion of the various service wells 120 will extend through portions of the subterranean zone 106.

Circulation of the cooling fluid through the horizontal portions of the service wells 120 causes native water in the subterranean zone to convert to ice. This, in turn, creates a substantially horizontal frozen barrier. The frozen barrier serves as the topseal 108. In relatively cold soils such as those found in the Canadian oil sands of northern Alberta, wells carrying a cooling fluid may be spaced up to about 5 meters apart to achieve a frozen layer. According to H.J. Jessberger et al. in Chapter 2.4 of *Geotechnical Engineering*

Handbook (Ulrich Smolczyk ed. 2002, Ernst & Sohn), continuous freezing may occur within about a year.

In one arrangement of cooling wells, the wellbores, especially for shallow formations, have so-called "river-crossing borings." This means that the wellbores go down into the subterranean zone 106, run largely horizontally, and then bend upwards to return to the surface 102. This arrangement simplifies the coolant circulation process. Such an arrangement may be attractive in northern Alberta, considering the shallow depths of the oil sands located there.

The use of the service wells 120 as cooling wells will require fluid circulating equipment, including fluid pumps and refrigeration equipment. Such equipment is represented schematically at 125 in Figure 1A. Such equipment may be run continuously until the frozen horizontal barrier is completed, and then run intermittently to maintain the artificial barrier 108 in a frozen state. However, where a horizontal frozen barrier is employed as the topseal, operating temperatures in the subsurface formation 110 may need to be kept low so as not to rapidly melt the topseal. This is so even if the circulation of the cooling fluid is continued after the artificial barrier 108 is constructed. In one aspect, light non-condensable gases may be injected into the top of the subsurface formation 110 to create an insulative later at the top of the formation 110. Such light gases preferably include hydrocarbon solvents in the C₃-C₅ range of components, but may also include inert gases such as nitrogen or helium.

The use of subsurface freezing to provide a barrier to fluid flow is known in the art. Shell Exploration and Production Company has discussed the use of freeze walls at the periphery of an oil shale production area in several patents, including U.S. Pat. No. 6,880,633 and U.S. Pat. No. 7,032,660. Shell's '660 patent uses subsurface freezing to protect against groundwater flow and groundwater contamination during *in situ* shale oil production.

U.S. Pat. No. 4,860,544 describes a method for creating a closed, flow-impervious cryogenic barrier by extending an array of freeze wells at angles into the earth. This forms an array of inverted, tent-like frozen structures below the earth surface. Similarly, U.S. Pat. No. 3,267,680 describes the formation of freeze walls of increased mechanical strength by using a series of freeze wells that alternate in angle. Specifically, every other well is vertical while the intermediate wells are 3° to 30° off of vertical. U.S. Pat. No. 3,559,737 describes forming an underground gas storage chamber by sealing caprock

fractures of a permeable formation using cryogenic cooling. Use of a downhole throttle is disclosed as a means of cooling.

Additional patents that disclose the use of so-called freeze walls include U.S. Pat. Nos. 3,528,252; 3,943,722; 3,729,965; 4,358,222; and 4,607,488. WO Pat. No. 98996480 is also of interest. Also, K. Stoss and J. Valk, "Uses and Limitations of Ground Freezing with Liquid Nitrogen", *Engineering Geology*, 13, pp. 485-494 (1979); and R. Rupprecht, "*Application of the Ground-Freezing Method to Penetrate a Sequence of Water-Bearing and Dry Formations – Three Construction Cases*", *Engineering Geology*, 13, pp. 541-546 (1979) discusses subsurface freezing techniques.

Figure 2A provides a cross-sectional view of an illustrative cooling well 220A where refrigeration occurs downhole. The cooling well 220A is an example of a service well 120 from Figure 1A as may be used in the formation of the artificial barrier 108. In Figure 2A, the well 220A is seen traversing from the earth surface 102, through the near-surface strata 104, and into the subterranean zone 106.

The cooling well 220A defines a bore 225 cut through the near-surface strata 104 and into the subterranean zone 106 using any known drilling procedure or technique. The bore 225 of the cooling well 220A is lined with a string of casing 222. The string of casing 222, in turn, is sealed into place using a curable material such as cement 224. The cement 224 not only supports the casing 222 in the well 220A, but also prevents the migration of fluids along the wellbore 225 between the near-surface strata 104 and the subterranean zone 106. The casing 222 and cement 224 preferably are not perforated at any point.

Within the casing 222 is a working string 230. The working string 230 may be, for example, a string of tubing, a string of drill pipe, or coiled tubing. Preferably, the working string 230 is centralized within the casing 222 through centralizers or collars (not shown). The working string 230 defines a bore 235 that receives a cooling fluid. The working string 230 extends from the earth surface 102 to an end 240 of the cooling well 220A.

The cooling well 220A includes an extended horizontal portion 206. The horizontal portion 206 runs along the plane of the subterranean zone 106. Circulation of the cooling fluid causes water residing in the pore space of the subterranean zone 106 to freeze. The water may be native water.

A circulation path for the cooling fluid is seen in Figure 2A. The cooling fluid is injected into the bore 235 of the working string 230, as seen by arrows "I." The cooling fluid travels under pressure to the end 240 of the cooling well 220A, and then returns to the earth surface 102 through an annulus 232 formed between the working string 230 and the surrounding casing 222. Arrows "A" demonstrate flow of the cooling fluid through the annulus 232.

The cooling fluid serves as a working fluid for distributing cold energy to the subterranean zone 106. Upon return to the surface 102, the cooling fluid is captured at a wellhead (not shown). From there, the cooling fluid is rechilled in equipment 125 (seen in Figure 1A) and recirculated.

Various types of fluids may be used as a cooling fluid, not all of which require downhole refrigeration. U.S. Pat. No. 3,372,550 discloses the use of a carbon dioxide slurry as a subsurface cooling fluid. U.S. Pat. No. 3,271,962 describes a method of freezing the earth around a mine shaft using multiple freeze wells connected to a common subterranean cavity. The use of brines or partially frozen brine slurries as cooling fluids is disclosed. Particularly suitable cooling fluids for circulation through cooling well 220A include a fluid comprised at least of 50 mol. percent of propane, propylene, ethane, ethylene, or a mixture thereof.

In one aspect, the cooling fluid may be chilled prior to injection into the well 220A. For example, a surface refrigeration system (part of surface equipment 125) may be used to chill the cooling fluid. However, the working string 230 will most likely need to be insulated near the surface 102 to prevent a significant loss of cold energy to the near-surface strata 104.

As an alternative, the surface refrigeration system is augmented or even replaced by a gas compression system and a downhole expansion valve 234. It is known that certain compressed gases when expanded through a valve undergo significant cooling. Use of a downhole expansion valve 234 to cause cooling of the circulating fluid has the benefit of removing or significantly reducing "cold energy" losses to the overburden (that is, the near-surface strata 104) while transporting the cooling fluid from the surface 102 to the subterranean zone 106. In addition, use of a downhole expansion valve 234 reduces or even removes the need for wellbore insulation along the near-surface strata 104 as the cooling fluid need not be completely chilled prior to injection.

In operation, gas is compressed in the gas compression system at the surface 102. The compressed gas is then cooled to near-ambient temperature via air or water cooling. In some cases, the gas may be further cooled via refrigeration. None, some, or all of the fluid may be in a condensed state after the cooling steps. The cooling fluid is then sent down the bore 235 of the working string 230, and through the expansion valve 234. This causes the fluid to cool via the Joule-Thomson effect.

Preferably, the expansion valve 234 is just above or within the subterranean zone 106. The cooling fluid is allowed to absorb heat from the surrounding formation, which in turn leads to ice formation within the subterranean zone 106. Preferably, the cooling fluid is at a temperature of about -20° F to -120° F after passing through the expansion valve 234. More preferably, the cooling fluid is at a temperature of about -20° F to -80° F after passing through the expansion valve 234. More preferably still, the cooling fluid is at a temperature of about -30° F to -60° F after passing through the expansion valve 234.

Preferably, the cooling fluid is at a pressure of about 100 psia to 2,000 psia before passing through the expansion valve 234, and about 25 psia to about 500 psia after passing through the expansion valve 234. More preferably, the cooling fluid is at a pressure of about 200 psia to 800 psia before passing through the expansion valve 234, and about 40 psia to about 200 psia after passing through the expansion valve 234.

As noted, the expansion valve 234 may be placed along the working string 230 in the cooling well 220A at different locations. In addition, more than one expansion valve 234 may be used. Figure 2B is a cross-sectional view of a cooling well 220B, in an alternate embodiment. In this cooling well 220B, two expansion valves 234' and 234'' are placed along the horizontal portion 206 of the bore 225 and within the subterranean zone 106. In this arrangement, both expansion valves 234', 234'' are within the bore 235 of the working string 230.

The use of two expansion valves 234' and 234'' permits a more uniform cooling temperature along the horizontal length of the cooling well 220B than would be possible with a single expansion valve. This, in turn, may lead to a more uniform impermeable barrier 108 over the subsurface formation 110 targeted for production.

In operation, a first temperature drop is accomplished as the cooling fluid moves through the first expansion valve 234'. The cooling fluid then imparts cold energy to the subterranean zone 106 on the way down. A second temperature drop is then accomplished

as the working fluid moves through the second expansion valve 234''. The working fluid may then impart additional cold energy to the subsurface formation 106 on the way back up the annulus 232.

It is noted that the relative placement of valves 234' and 234'' is a matter of designer's choice. In addition, the sizing of the inner diameters of the expansion valves 234', 234'' is a matter of designer's choice. The placement and the sizing of the expansion valves 234', 234'' may be adjusted to provide for selective pressure drops. In one aspect, the cooling fluid is at a pressure of about 800 psia to 3,000 psia before passing through the first expansion valve 234', 500 psia to 2,000 psia before passing through the second expansion valve 234'', and about 25 psia to 300 psia after passing through the second expansion valve 234''. More preferably, the cooling fluid is at a pressure of about 800 psia to 2,000 psia before passing through the first expansion valve 234', about 100 psia to about 500 psia after passing through the first expansion valve 234', and about 25 psia to 100 psia after passing through the second expansion valve 234''.

In the cooling well 220B of Figure 2B, both expansion valves 234' and 234'' create a Joule-Thompson effect for the cooling fluid within the bore 235 of the working string 230. However, it is feasible to provide one or both of the pressure drops outside of the bore 235. This would involve placement of one or both of the valves between the bore 235 and the surrounding casing 230, that is, within the annulus 232 along the horizontal portion 206 of the cooling well 220B.

When using downhole expansion valves, a number of cooling fluids are suitable. Suitable fluids may include C₂-C₄ hydrocarbons (e.g., ethane, ethylene, propane, propylene, isobutane, and n-butane) or mixtures containing a majority of one or more of these components. Other suitable components may include refrigerant halogenated hydrocarbons, carbon dioxide, and ammonia. The specific compositional choice for a cooling fluid depends on a number of factors including working pressures, available pressure drop through the valve, thermodynamic behavior of the fluid, temperature limits of the metallurgy of the conduits, safety considerations, and cost/availability considerations. Additional technical descriptions of working fluids and their uses in forming freeze walls have been described in U.S. Pat. Nos. 7,516,785 and 7,516,787. These patents also disclose additional cooling well embodiments. These patents are assigned to ExxonMobil Upstream Research Company.

It is optional to provide insulation to the elongated working string 230 above the subterranean zone 106. In addition, the operator may employ an elongated U-tube as the working string. The U-tube provides a closed system through which the cooling fluid flows.

Still another option for forming an impermeable barrier 108 involves the use of electrokinetic deposited barriers. Electrokinetic barriers are thin, impermeable barriers formed by forced metal dissolution, ion migration, and precipitation. U.S. Pat. Publ. No. 2006/0163068 entitled "Method for Soil Remediation and Engineering," describes an electrokinetic method for groundwater protection. The method comprises applying an electric field across an area of soil so as to generate a pH and Eh gradient, and thereby promote the *in situ* precipitation of a stable iron-rich band. According to the published application, the method may be performed for, *inter alia*, the purpose of forced and directed migration of contaminated leachates.

In another example described by Faulkner *et al.*, *Mineralogical Magazine*, pp. 749-757 (Oct 2005), electrically stimulated iron rods may be placed in close relation within the subterranean zone 106. The approach was developed for contamination confinement. Preferably, the rods are oriented horizontally along the plane of the subterranean zone 106 to reduce the number of rods required.

A preferred embodiment for forming the impermeable barrier 108 involves the injection of a polymer solution. The polymer solution is injected in a liquid phase, but sets as an extremely viscous fluid, a stiff gel, or even as a solid. In one aspect, the polymer solution is a cross-linked polymer solution that slowly reacts *in situ* to form a substantially solid material or gel. The slowly cross-linking polymer solution is injected into injection wells 120. The polymer solution spreads out over days or weeks within the subterranean zone 106. The polymer solution then sets within the subterranean zone 106 as a gel.

To limit vertical migration and to help ensure coverage, the injected polymer solution fluids may optionally be flowed to production wells (not shown) that are completed at similar depths to the service wells 120. In addition, the cross-linked polymer solution may include a dense soluble material such as a salt. Use of a dense fluid helps to limit upward migration of the polymer solution and to promote its spreading as a relatively thin layer over the viscous oil deposit. In this way, an effective topseal, that is, a largely impermeable barrier to low-pressure fluid flow covering an extended area, is formed.

In another embodiment, the injected fluid is a temperature-sensitive solution that cools within the subterranean zone 106 and hardens *in situ*. Figure 3 presents a flow chart demonstrating a method 300 of plugging a subterranean zone above a subsurface formation using such a fluid. The method 300 employs a specially formulated waxy emulsion that is designed to be heated for injection into the subterranean zone 106. The composition comprises a water-in-oil emulsion with added wax to adjust the melting range. The emulsion fills the pores in the permeable subterranean zone 106, and hardens into a solid as it cools. In this way, the subterranean zone 106 is plugged to form an extended topseal.

In accordance with the method 300 of Figure 3, the operator of the reservoir (or a contractor or consultant) first formulates the waxy emulsion. This is shown generally at Box 310. The emulsion is a blend of liquids comprising oil, added wax, and water. An emulsifying agent and solvent may optionally be added to adjust the viscosity of the emulsion. The composition of the emulsion is designed so that the mixture will be a liquid above a targeted temperature, but gels or solidifies into a waxy matrix containing water droplets once the emulsion cools to below its melting range. In the present application, the melting range must be above the temperature experienced by the waxy matrix if heated vapor from the subsurface formation 110 contacts the subterranean zone 106 during the *in situ* recovery of viscous oils.

In one aspect, the emulsion is formulated to have a viscosity greater than that of any fluids residing within the zone 106 to be plugged. In this way, the injected emulsion efficiently displaces the *in situ* fluids, thus enhancing the ability to achieve effective plugging.

To operate in this manner, various reservoir characteristics and fluid factors are simultaneously considered. One factor is the temperature of the subterranean zone 106. The emulsion is formulated to have a melting point above this temperature. Another factor is the pressure range within the subterranean zone 106. A minimum gel strength required for the emulsion is deduced from the pressure prevailing within the zone 106. The operator may also consider the volume of the high permeability zone 106 to be plugged. This will determine the desired amount of waxy emulsion to be injected into the target zone 106. Sufficient emulsion volume is injected through the service wells 120 to reach a desired radius for the estimated void volume in the subterranean zone 106. The

operator injects the desired volume, plus a volume sufficient to fill the injection tubing of the service well 120.

Next, the viscosity of fluids in the target zone 106 is preferably determined. The purpose of the viscosity determination is to determine a desired viscosity for the waxy emulsion. The viscosity of the emulsion should be similar to or, preferably, greater than that of any resident fluids in the subterranean zone 106. Also, an oil may be selected for the waxy emulsion. The oil may be any oil that, when mixed with wax, makes a mixture that emulsifies with water in the presence of an emulsifying agent. The oil is preferably crude oil.

The emulsion will also include a wax. It is noted that in some produced crude oils, paraffins or other waxes may already be present in the production stream. However, such wax content may not be enough to cause a solidification of the emulsion at the anticipated subterranean zone 106 temperature. Therefore, the wax may be at least in part a wax additive or added wax. The added wax may be selected from a wide range of waxes that are soluble in oil. Examples include petroleum-derived waxes such as paraffins, or non-petroleum natural waxes, such as beeswax or vegetable wax. Numerous suppliers offer paraffin and non-paraffin containing hydrocarbon-based wax stocks that could be utilized in the current processes. One preferred source for wax is Imperial Oil Limited. The Imperial Oil Slack Wax product line provides various waxes with a broad range of melting points and physical characteristics for use as blending components.

The composition of the wax-oil mixture is chosen so that the waxy emulsion is liquid above a targeted temperature, but solidifies once the emulsion cools to below its melting range. Two variables generally determine the melting range of the hydrocarbon phase of the injected emulsion. These are the fraction of wax included, and the melting range of the individual wax component. A wax is selected that has a congealing point (the highest temperature of the melting range) sufficiently high so that mixtures of approximately one-half wax and one-half oil will have a melting range lower than the injection temperature, but higher than the desired stable operating temperature. The wax-oil mixture may have a congealing point of approximately 20° C to about 80° C above the temperature in the subterranean zone 106.

Additional details for selecting a wax and for formulating a wax-oil mixture is disclosed in co-owned WO 2008/024147, entitled "Composition and Method for Using

Waxy, Oil-External Emulsions to Modify Reservoir Permeability Profiles.”

In one manner of formulation under Box 310, a series of mixtures of a selected wax and oil are prepared. The melting range of each mixture is empirically measured. The preferred method for measuring the melting range is to measure viscosity versus temperature in a rheometer, such as the Viscoanalyzer VAR 100™ manufactured by Reologica Instruments, or the HBDV-III viscometer, manufactured by Brookfield Instruments. The melted sample is placed in the instrument at a temperature above the melting range, and the viscosity is measured versus shear rate for a series of decreasing temperatures. As the temperature drops below the upper temperature of the melting range, the viscosity of the wax-oil mixture increases dramatically, indicating the melting range.

The measured value of the lowest temperature of the melting range, that is, the temperature at which total solidification occurs, may vary depending upon the method used. For example, a scanning differential calorimeter often reveals a lower solidification temperature than visual or rheometric measurements. However, for purposes of applying the plugging method 300, precise measurement of the solidification point is not required. Measuring the temperature at which wax crystals are first noted is sufficient, and the fluid composition is designed and the injection temperature is controlled based on that temperature. While the waxy emulsion may continue to be injected and flow through porous rock at temperatures below this upper temperature limit of the melting range, designing the system so that this limit is not reached by the fluid prior to entering the subterranean zone 106 ensures that the process is effective.

If a viscous, heavy crude oil is chosen as the oil, it may be desirable to add a solvent to the emulsion. The addition of diluent solvent reduces the hydrocarbon phase viscosity. This, in turn, reduces the viscosity of the injected emulsion, as the viscosity of the emulsion is primarily controlled by the viscosity of the external hydrocarbon phase. Different solvents may be used to reduce the viscosity of the emulsion. Examples include kerosene and Varsol™. Varsol™ is a product of Imperial Oil Limited. Varsol™ (a refined middle distillate) is commercially used for automotive cleaning to remove oil and grease. It is also used for thinning oil-based paints, varnishes, and polyurethanes.

Depending on the composition of the wax-oil mixture, changes in viscosity and melting range due to the addition of solvent may or may not be significant. Empirical measurements may be made on mixtures to determine the impact of diluent solvent

addition. By making measurements of viscosity and melting range for various possible mixtures, the operator may choose a composition that meets the desired viscosity and melting range. Preferably, the actual target viscosity of the hydrocarbon blend is chosen so that when a waxy emulsion is made containing approximately 40 to 60 volume % of water, the emulsion has a viscosity approximately 1.25 to 3 times greater than that of the fluids residing within the subterranean zone 106 to be plugged. This ensures that the emulsion has a favorable mobility ratio displacement of the fluid existing within the high permeability zone 106 to be plugged, while still maintaining a viscosity low enough to be injected easily. Such a favorable mobility fluid will more effectively displace the resident fluid and achieve a more uniform plug that better conforms to the volume distribution of the high permeability zone after cooling.

In addition to a solvent, the operator may optionally choose to add an emulsifying agent. Surfactants may be used as emulsifying agents. The surfactants may be either ionic or non-ionic. If surfactants are used, the surfactant type and concentration should be chosen so that the mixture forms an oil-external emulsion with water droplets having diameters of approximately 1 to 10 microns. Water droplets with larger diameters tend to be less stable and may rupture during injection into the reservoir. Therefore, they are not recommended.

The operator may also determine a desired water content for the waxy emulsion. By definition, the emulsion includes not only oil, but at least some water. The emulsion formed is a water-in-oil emulsion. Water is desirable in the emulsion for several reasons. First, including water in the injected fluid significantly reduces the cost per volume of the fluid, because water is significantly less expensive than oil or other additives. Second, the water, included as internal droplets in an oil-external emulsion, produces a fluid which has significantly higher viscosity than that of either the individual oil or water phases. The viscosity of the emulsion may be adjusted by varying the water content. Therefore, the resulting emulsion may be designed to have favorable mobility displacement of any water in the subterranean zone 106. Third, the presence of water increases the heat capacity of the injected fluid, allowing the injected fluid to retain heat for a longer period compared to a single-phase wax. Because water has a higher specific heat capacity than oil, including water as the internal phase allows the injected fluid to have a greater heat capacity. This also allows the injected fluid to cool more slowly and penetrate into the zone 106 farther than if oil were the sole phase injected.

The method described in Box 310 of Figure 3 allows the injection of a waxy emulsion in liquid form to achieve effective penetration into the subterranean zone 106 at distances from the service wells 120. The method of Box 310 also provides for adjusting the fluid viscosity during injection by changing the solvent or water content to provide favorable mobility displacement of fluids residing in the zone 106 during placement. Because of the presence of added wax in the emulsion, the emulsion will have a melting range that is above a targeted temperature. Thus, after a period of curing, a solidified plug is created that may provide an artificial barrier 108 to escaping vapors.

Referring again to Figure 3, the plugging method 300 also involves blending the waxy emulsion. This is shown at Box 320. The hydrocarbon phase components (wax, oil, and any added diluent solvent (if desired)) are mixed in a suitable storage tank. Alternatively, separate supply tanks of the wax, oil, and solvent may be used, and the components continuously mixed in-line during injection, so that the desired final composition is maintained within specifications. To blend the emulsion, the hydrocarbon mixture is blended and sheared, together with any emulsifying agent and the selected volume ratio of water, in a suitable mixing device such as an in-line blender.

During storage of liquids and subsequent mixing, the tanks and surface flow lines may be heated and insulated to maintain the temperature of the liquids. Preferably, the temperature of the liquids is maintained at approximately 20° C to 80° C above the melting range of the waxy emulsion. The emulsion may then be mixed on the surface using pre-heated fluids. The emulsion may optionally be further heated after mixing. Thus, blending 320 encompasses any heating process for obtaining a temperature of the final emulsion blend that is above the melting range of the emulsion.

It may be desirable to also heat the service well 120 before injecting the waxy emulsion into the subterranean zone 106. An optional wellbore heating step is shown at Box 330. Heating may be accomplished by circulating steam through the injection string and back up the annulus. Depending upon the injection well completion design and its temperature profile from surface to the bottom of the service well 120, steam may also be injected into a portion of the subterranean zone 106 prior to injecting the emulsion. This raises both the wellbore and subsurface temperatures to above the melting range of the emulsion. This helps prevent premature cooling and solidification of the emulsion.

After sufficient heating of the waxy emulsion and, optionally, the wellbore, the emulsion is injected into the service well 120 and surrounding subterranean zone 106. The

plugging agent is injected as a heated, liquid emulsion wherein the hydrocarbon phase contains a wax component. The injection step is indicated at Box 340. Upon injection, the emulsion fills the pore spaces of the subterranean zone 106.

During the injection step of Box 340, sufficient waxy emulsion volume is injected to reach a radius of investigation desired to fill the high permeability region to be plugged or the estimated void volume. The preferred injection mode is to inject the waxy emulsion as fast as possible without exceeding the formation fracture pressure until the desired volume is injected. Injecting at slower rates result in less invasion due to decreasing fluid mobility and increasing flow resistance caused by the formation of a wax structure in the emulsion as the temperature cools into and below its melting range. Because the emulsion is a heated liquid, injection pressure during the injection in Box 340 may not rise significantly above the formation pressure.

Following injection of the waxy emulsion, a small volume of fluid may be injected to displace the tubing volume from surface to the injection depth. This displacement is shown at Box 350 of Figure 3. The fluid is injected to displace any emulsion within the injection string that may solidify and plug the string following shut down. The fluid is preferably steam.

After the displacement step in Box 350, the subterranean zone 106 is allowed to cool. The purpose is to cure the waxy emulsion *in situ*. This curing step is shown in Box 360. Curing 360 is accomplished by shutting in the service well 120. The well 120 should remain shut in for a period of time estimated from experimental data and computations to be sufficient to allow the injected emulsion within the zone 106 to cool to below its melting range and reach the desired gel strength. The operator should determine the period for curing based upon the anticipated temperature profile of the subterranean zone 106 and the expected rate of cooling of the injected emulsion. Because the subterranean zone 106 is typically relatively shallow, cooling should take place fairly quickly, such as within 2 to 5 days.

Once in place within the target zone 106, the waxy emulsion cools to a temperature below its melting range. Upon cooling below the melting range, the external hydrocarbon phase surrounding the water droplets within the emulsion solidifies, forming a topseal.

Following curing in Box 360, the operator may optionally circulate a heated cleaning fluid. This is represented by Box 370. The cleaning fluid will be oil or an emulsion of oil, water, and perhaps, solvent. Alternatively, only a solvent could be used.

Kerosene or other middle distillates, preferably containing some aromatic components, may be used. The heated fluid serves to melt and clean out any solidified plugging agent remaining within the service wells 120.

During circulation in Box 370, some plugging agent will be returned to the surface 102. The used waxy emulsion is collected for either recovery or disposal. The service wells 120 are then shut in.

In an alternate embodiment of the invention, one or more additional injections of the waxy emulsion are made after curing in Box 360. The injections are referred to as "squeezes." The injection in Box 340, displacement in Box 350, cooling in Box 360, and circulating in Box 370 together may be designated as the first squeeze. Preferably, two or more additional squeezes of the waxy emulsion are conducted sequentially to effectively plug the high permeability zone 106.

Following the cooling period in Box 360 and, optionally, the circulating in Box 370, another volume of waxy emulsion is injected as part of a second squeeze. Injection is intended to fill any voids remaining after the first injection in Box 340, and to fill additional high permeability pathways not contacted by the first injection. Injection pressure during the second (and optional third) injection typically rises significantly above that observed during the first injection. Injection may be continued until a sufficiently high pressure is reached or the desired additional volume is injected. Again, the injection pressure should not exceed the fracture pressure for the formation.

The terminal pressure should be held for several hours by shutting in injection, allowing the pressure to partly decline, and then refilling the injection string with additional waxy emulsion to maintain an elevated pressure on the squeeze. After the rate of pressure decline has slowed, indicating that the emulsion is beginning to solidify and provide more flow resistance, another small volume of oil may be injected to just displace the tubing volume from surface to the injection depth. This is shown at Box 370. The service wells 120 are again shut in to allow the emulsion to cool and solidify.

After the final waxy emulsion injection, a cleanup operation may be conducted. This is in accordance with Box 380. Heated oil or solvent is circulated through the service wells 120 to remove solidified plugging agent in and near the wellbore.

A benefit of the use of the waxy emulsion as the plugging agent for the artificial barrier 108 is that the solidified waxy emulsion may be substantially removed from the subterranean zone 106 at a later time. In this regard, after the *in situ* recovery process for

viscous oils from the subsurface formation 110 is completed, the heated oil or other hot cleaning fluid may be circulated within the service wells 120 to bring the temperature in the subterranean zone 106 up through the melting range of the emulsion. After the waxy emulsion has been re-liquefied, the emulsion may then be at least partially swept out from the subterranean zone 106 through injection of steam. Selected injection wells will be converted to production wells to produce the emulsion back to the surface.

Another option for forming an impermeable barrier 108 relates to the placement of a solidifying fluid into the subterranean zone 106. The solidifying fluid is injected into the subterranean zone 106, where it chemically reacts *in situ* to form a solid precipitate. This leads to pore plugging and permeability reduction of the formation rock in the subterranean zone 106. A number of *in situ* precipitation methods have been proposed for modifying local permeability in a subsurface reservoir so to reduce flow into wells. Examples of such methods are disclosed in U.S. Pat. No. 3,684,011, U.S. Pat. No. 3,730,272, U.S. Pat. No. 4,002,204, U.S. Pat. No. 5,244,043, and U.S. Pat. No. 6,401,819. Such methods may form precipitates from salts of metals, sulfates, bicarbonates, asphalts, or organic substances. In some embodiments, the precipitation or gelling chemistry may be chosen to be temperature-sensitive such that permeability reduction occurs or increases when heat from a recovery mechanism interacts with the fluids which were injected to form a barrier.

Referring again to Figure 1A, the oil field 100 targets the subsurface formation 110 containing viscous hydrocarbons such as bitumen. The viscous hydrocarbons are in an unheated and immobile state. However, it is desired to recover the viscous hydrocarbons from the subsurface formation 110 by heating the viscous hydrocarbons in order to convert them to a mobilized and producible state. Heating of the subsurface formation 110 may reduce viscosity of *in situ* hydrocarbons from a value substantially greater than 1,000 cp to substantially less than 100 cp.

In Figure 1A, it can be seen that two sets of wells are completed in the subsurface formation 110. Each set contains at least one heat injection well 130 and at least one production well 140. The wells 130, 140 are slightly offset in Figure 1A for visibility purposes. The heat injection wells 130 are used for injecting steam or other heated vapor into the subsurface formation, while the production wells 140 are used for producing mobilized hydrocarbon and condensed steam.

Preferably, each set of wells 130, 140 represents a pair of wells, meaning one heat injection well 130 with one production well 140, as shown in Figure 1A. In addition, it is preferred that both the heat injection well 130 and the production well 140 be completed horizontally to elongate the heating and production aspects of the wells 130, 140. This is demonstrated in Figure 1A, with the wellbores forming the heat injection 130 and production 140 wells illustratively extending out of the page.

The subsurface formation 110 has an upper portion 114 and a lower portion 116. Preferably, the horizontal portions of the heating 130 and production 140 wells are completed in the lower portion 116 of the subsurface formation 110. As steam or other heated vapor is injected through the heat injection wells 130 and into the subsurface formation 110, the vapor will rise through the subsurface formation 110. Further, as the viscous hydrocarbons in the subsurface formation 110 are mobilized, they will drain by operation of gravity towards the bottom of the subsurface formation 110. Therefore, placement of both the heating wells 130 and the production wells 140 at the lower portion 116 of the subsurface formation 110 is preferred.

Figures 1A through 1F together show the process of heating the subsurface formation 110 and then recovering mobilized hydrocarbons. In Figure 1A, no heating has yet taken place in the subsurface formation 110. In Figure 1B, steam or other heated vapor has begun to be injected into the subsurface formation 110 through the heat injection wells 130. Viscous oils are being heated in a small but growing steam chamber 135.

The heated fluid being injected into the steam chamber 135 has a temperature considerably higher, e.g. 150° F to 1,000° F, than the temperature of the subsurface formation 110 into which it is injected. The heated fluid could be a heated gas or liquid such as steam, and may also contain surfactants, solvents, oxygen, air, and inert inorganic gases. However, because of its high heat content per unit mass, steam is ideal for raising the temperature of a reservoir and is especially preferred for practicing the inventions disclosed herein. Thus, the amount of heat that is released when steam condenses is very large. Because of this latent heat, viscous oil reservoirs may be effectively heated.

The operator may pre-determine a volume of steam to be injected. Several factors will affect the volume of steam. Among these are the thickness of the hydrocarbon-containing formation 110, the viscosity of the bitumen or other oil-in-place, the porosity of the formation, the saturation level of the hydrocarbon, water in the formation, and the

fracture pressure. Generally, the total steam volume injected may vary between about 1 and 5 liquid equivalent barrels per barrel of oil produced.

Various ways may be employed for initiating a steam injection process. In the beginning, steam may optionally be injected into the subsurface formation 110 through both the injection wells 130 and the production wells 140. Alternatively, heated vapor may be injected into the subsurface formation 110 only through the heat injection wells 130, but also circulated within the production wells 140. Circulation of heated vapor within the wellbores of the production wells 140 increases the temperature of the subsurface formation 110 around the production wells 140 through thermal energy.

Figure 4 is a cross-sectional view of a pair of wells, representing a heat injection well 430 and a production well 440, in one embodiment. The wells 430, 440 are placed within subsurface strata of an oil field 400. As with Figures 1A and 1B, the subsurface strata of the oil field 400 of Figure 4 include near-surface strata 104 and subterranean zone 106. An artificial barrier 108 is again in place in the subterranean zone 106 in order to provide a topseal.

The subsurface strata of the oil field 400 also includes a subsurface formation 410 having viscous oil. In this illustrative arrangement, the subsurface formation 410 is a tar sand deposit. The heat injection well 430 and the production well 440 are completed in a lower portion 416 of the tar sand deposit

In the arrangement of Figure 4, the production well 440 is completed substantially horizontally. In this respect, the production well 440 includes a horizontal portion 446 that extends along the lower portion 416 of the tar sand deposit 410. The horizontal portion 446 is preferably drilled so that it extends along the fracture trend of the formation containing the tar sands deposit 410.

The production well 440 is completed with a perforated or slotted casing 442. In addition, the production well 440 has concentric inner tubing strings 443 and 444 within the slotted casing 442. The concentric tubing strings 443, 444 terminate inside of the casing 442 at a level near the lower portion 416 of the tar sands deposit 410. However, the horizontal portion 446 of the production well 440 with the slotted casing 442 extends well past the tubing strings 443, 444 and along the tar sands deposit 410. This manner of completion together with the appropriate production rate helps to ensure that a relatively high oil saturation exists adjacent to the horizontal portion 446 so that the horizontal portion 416 of the production well 440 remains full of liquid.

As noted, the oil field 400 also includes a heat injection well 430. In the arrangement of Figure 4, the heat injection well 430 is completed substantially vertically, although in other embodiments the well may be deviated or horizontal. The heat injection well 430 extends to near the top of the horizontal portion 446 of the production well 440. Preferably, the bottom of the heat injection well 430 will extend to within about 5 to 10 feet from the top of the horizontal portion 446 of the production well 440, but depending on the nature of the tar sand deposit 410 may be as far as 100 feet. Smaller clearances will be used if it is desired to achieve thermal communication without fracture or if the direction of fractures is hard to predict.

The heat injection well 430 is completed with a slotted liner 432 for steam injection. In operation, steam (or other heated vapor) is injected into the formation via well 430 below the fracture pressure of the formation 410 holding the tar sands deposit. Mobilized heavy oil drains towards the nearly horizontal portion 416 of well 440. Tubing strings 443 and 444 terminate at a distance which is calculated to maintain the main horizontal portion 416 of the production well 440 full of liquid with throttled production.

It is noted that while the illustrative production well 440 is completed with two concentric strings of tubing 443, 444, in many cases a dual tubing completion will suffice. The use of a third tubing string allows an insulating gas to be introduced into the annulus between the inner two tubing strings, but this is an optional feature.

The described configuration of wells 430, 440 promotes separate oil and water flowpaths, thereby maintaining high oil relative permeability. In addition, any non-condensable gases which may accumulate in the tar sands deposit 440 may be purged near an upper portion 414 of the tar sands deposit 440 via an outer annulus of the production well 440 via the slots in casing 442. These slots extend up the casing 442 to near the upper portion 414 of the reservoir.

It is noted that the producer may elect not to fracture the formation holding the tar sands deposit 410. This may be desirable for the drainage of oil from oil sands that are not very deeply buried and where fracturing may be uncontrollable or where fluid communication may be established without fracturing. The technique may also be used where it is desired to drill the horizontal production well 440 in a direction other than along a fracture trend. For example, the operator may desire to drill perpendicularly from the shore of a small lake which contains an oil sand reservoir beneath it. In such cases, it is particularly desirable to have the injection well 430 closer than usual to the horizontal

portion 416 of the production well 440 so that initial thermal communication may be established fairly rapidly by thermal conduction.

It is understood that the current inventions are not limited to the type of recovery process as long as it maintains the physical integrity of the barrier. In practice, this will generally mean the recovery process utilizes relatively low pressures, e.g., non-fracturing pressures, so as not to rupture the relatively thin and, possibly, gel-like, artificial topseal barrier. For example, a low pressure steam flood may be applied as the recovery process where steam is continuously flowed from an injection well to a production well. Furthermore, other arrangements for pairs of wells may be employed. Examples of such arrangements are described in U.S. Pat. No. 4,344,485 mentioned above in the Background section. Figure 2 of the '485 patent displays a production well (10) completed horizontally below a horizontally completed heat injection well (11). Figure 3 of the '485 patent depicts a production well (40) and a heat injection well (41), wherein each well is completed vertically.

In any of these arrangements, steam is injected into the subsurface formation at pressures and rates sufficient to create a large steam chamber to cause gravity drainage of the mobilized heavy oil. Injection pressures are usually within the range of about 50 to 1,000 psig, and preferably about 100 to 600 psig, during the oil recovery phase. Of course, lower pressures may be employed if a pump such as a conventional sucker rod pump or, preferably, a chamber lift pump, is provided at the bottom of the production well.

Referring now to Figure 1C, Figure 1C provides another side view of the oil field 100. Here, steam or other heated vapor continues to be injected into the subsurface formation 110. It can be seen that the steam chambers 135 continue to grow away from the heat injection wells 130. The steam chambers 135 produce condensate, both from injected gas and from mobilized viscous oils in the subsurface formation 110.

In addition to the steam chambers 135, oil drainage layers 145 have also been formed. The oil drainage layers 145 represent areas of lesser pressure around the steam chambers 135, where viscous oils have been mobilized into flowable heavy oil. The flowable heavy oil flows around and through the steam chambers 135 and into the production wells 140, primarily by means of gravity drainage. Thus, this represents a low-pressure production method.

It is noted that once sizeable steam chambers 135 have been established such as is shown in Figure 1C, it may be desirable to reduce the steam injection pressure. For example, it may be desirable to operate at formation pressures significantly below the fracture pressure. This represents another aspect of a low-pressure production method. Injection pressure is limited to the fracture pressure, which may be as low as between about 50 and 200 psia.

Figure 1D presents another cross-sectional view of the subsurface strata from the oil field 100. Here, heated vapor continues to be injected into the subsurface formation 110. The steam chambers 135 continue to expand above and away from the heat injection wells 130. In the view of Figure 1D, the steam chambers have reached the top of the subsurface formation 110. Beneficially, the artificial barrier 108 is acting as a topseal, preventing the vertical migration of steam out of the subsurface formation 110. Small oil drainage layers 145 remain at the tops of the steam chambers 135.

Figure 1E provides yet another side view of the oil field 100. Here, steam or other heated vapor continues to be injected into the subsurface formation 110. It is understood that the heated injectant will rise within the subsurface formation 110, causing mobilization of viscous hydrocarbons in the upper portion 114 of the hydrocarbon formation 110 before the lower portion 116.

It can be seen in Figure 1E that the steam chambers 135 have substantially filled the upper portion 114 of the hydrocarbon formation 110. The oil drainage layer 145 above the steam chamber 135 is almost gone, indicating successful mobilization of viscous hydrocarbons up to the artificial barrier 108. In addition, the steam chambers 135 have essentially merged into a single steam chamber.

Because the steam chambers have merged into a single chamber 135, a single oil drainage layer 145 is also formed. Heavy oil flows from the oil drainage layer 145 into the production wells 140.

It is noted that the temperatures and pressures associated with the steam injection and corresponding viscosity reduction are effective in recovering a substantial portion of the viscous oils *in situ*. The steam chambers 135 may be created at a temperature range of about 350° C down to about 150° C, depending on the *in situ* pressure. However, such temperatures and accompanying injection pressures may not be compatible with the material forming the artificial barrier 108 throughout the life of the operation. For example, if the artificial barrier is a frozen barrier or a temperature-sensitive polymer, then

the operator may need to discontinue steam injection as the steam chamber 135 approaches the subterranean zone 106.

The operator may monitor temperatures in the subterranean zone 106 using sensors placed in the service wells 120. If the operator receives feedback suggesting that the temperature is approaching a melting point of the plugging material forming the artificial barrier 108, then steam injection may be discontinued.

In order to recover an additional amount of oil from the subsurface formation 110, the operator may choose to inject a light hydrocarbon solvent into the previously formed steam chambers 135. The solvent is in the C₃ to C₁₀ range of components, and more preferably in the C₃ to C₅ range.

Figure 1F provides a final cross-sectional view of the subsurface strata from the oil field 100. Here, a light hydrocarbon solvent is being injected into the subsurface formation 110 through the heat injection wells 130. The solvent may be mixed with steam to form the heated vapor. In any instance, the heated vapor has caused the steam chamber 135 to substantially fill the hydrocarbon formation 110. The production wells 140 continue to receive heavy oil from the oil drainage layer 145 through gravity.

Given the low operating pressures in the subsurface formation 110, the sole use of steam to reduce the viscosity of the *in situ* oil may be impractical, even during earlier phases of oil recovery. The addition or substitution of solvent may enhance viscosity reduction. Moreover, as noted, if the integrity of the topseal (artificial barrier 108) is temperature-sensitive, solvents may permit the use of temperatures significantly lower than that of pure steam. In some embodiments, solvents (with no steam) largely in the C₃ to C₅ range may be injected in a heated vapor state. The solvents will condense *in situ* at about 30° C or less at shallow *in situ* pressures. *In situ* temperatures of shallow bitumen resources in Canada are typically 10° to 15° C.

It is also noted that the use of light hydrocarbon solvents may provide some degree of *in situ* upgrading of the heavy oil. Solvents may precipitate out a portion of low-value asphaltene components in certain viscous oils.

In lieu of steam or heated solvents, the operator may choose to use other heating methods for the subsurface formation 110. For example, the heat injection wells 130 may be part of an electric heating arrangement. Several ways of performing electrical heating of viscous oil deposits have been described, including electrical wellbore heaters.

U.S. Pat. No. 3,149,672 is entitled “Method and Apparatus for Electrical Heating of Oil-Bearing Formations.” In the ‘672 patent, an electrical current is passed between sets of fractures that are propped with electrically conductive particles. One set of fractures may be in an upper portion of a formation, while the other set may be in a lower portion of the formation. Passing the electrical current through the formation generates electrically resistive heat. The purpose is to warm “viscous oil.”

Also, a method of resistively heating a formation by passing electricity between wellbore electrodes in the formation has been discussed in Paper 2008-209, “*Electro-Thermal Pilot in the Athabasca Oil Sands: Theory Versus Performance*,” Canadian International Petroleum Conference (2008).

U.S. Pat. No. 7,331,385 is entitled “Methods of Treating a Subterranean Formation to Convert Organic Matter into Producing Hydrocarbons.” This co-owned patent involves a process of heating organic matter in a subsurface formation *in-situ* to create and recover producible hydrocarbons. The formation may contain a solid organic matter such as kerogen, in which case heating causes pyrolysis of the solid matter. Alternatively, the formation contains heavy oil or tar sands, in which case heating causes a substantial reduction in fluid viscosity.

In the methods of the ‘385 patent, the formation is fractured from one or more wells. Subsequently, an electrically conductive material is injected into the fractures. The conductive material may be a proppant such as (i) thinly metal-coated sands, (ii) composite metal/ceramic materials, or (iii) carbon based materials. Alternatively, the conductive material may be a non-proppant such as a conductive cement. Sufficient heat is generated by electrical resistivity through the conductive material to pyrolyze at least a portion of the solid organic matter into producible hydrocarbons, or to reduce the viscosity of at least a portion of the heavy hydrocarbons.

Another heating method involves circulating hot fluids through closed-loop wells. U.S. Pat. No. 3,994,340 is entitled “Method of Recovering Viscous Petroleum From Tar Sand.” This patent mentions the circulation of a hot fluid through a wellbore as a means of reducing viscosity of “viscous petroleum.”

In another arrangement, the heat injection wells 130 may employ resistive heaters placed within boreholes or along cased portions of the injection wells 130. U.S. Pat. No.

7,011,154 is entitled "In Situ Recovery From a Kerogen and Liquid Hydrocarbon Containing Formation," and describes such an arrangement. The '154 patent lists the use of downhole "insulated conductor heaters" such as cables, rods and pipes. A current is passed through such conductive objects to generate resistive heat. Alternatively, the heating may be accomplished by conducting electricity through the formation to resistively heat a conductive brine.

Any of the above-described heating methods may be used in connection with the hydrocarbon recovery methods disclosed herein. In addition, monitoring wells (not shown) may be placed between resistive heating wells to determine when sufficient temperatures have been reached between heating wells to adequately mobilize *in situ* hydrocarbons.

Figure 5 is a flowchart showing steps for a method 500 of recovering a viscous hydrocarbon from a subsurface formation. The method may first include creating an artificial barrier in a subterranean zone. This is shown in Box 510. The artificial barrier may be formed using any of the methods described above so as to create a topseal.

The subterranean zone is typically made up of sand or other high-permeability matrix material. The subterranean zone is above or proximate a top of a subsurface formation. Preferably, the artificial barrier is formed within 5 meters of the top of the subsurface formation. The artificial barrier is largely impermeable to fluid flow.

The method 500 also includes heating the subsurface formation. This is provided in Box 520. The heating reduces the viscosity of the viscous hydrocarbon in the subsurface formation. Heating the subsurface formation also mobilizes the viscous hydrocarbon into a flowable heavy oil.

Heating may be conducted using any of the techniques described above. However, heating preferably involves injecting steam or a mixture of steam and a heated hydrocarbon solvent into the subsurface formation. Use of pure steam or vaporized heavier hydrocarbons (*e.g.*, C₇+) may be beneficial during the initial start-up of the gravity drainage process to speed the fluid connection of pairs of heat injection and fluid production wells. During later stages of development, a light hydrocarbon solvent may be preferred.

The method 500 further includes producing the heavy oil to the surface. This is indicated at Box 530. The production process uses a production method that maintains the integrity of the artificial barrier. An example is a gravity drainage method that provides

for essentially continuous production. Thermal transfer away from heat injection wells reduces the viscosity of the bitumen sufficiently that it may gravity drain to a production well at a commercially viable rate. The production method is compatible with the artificial barrier as a low pressure process. This means that the production method does not compromise the integrity of the topseal, such as by pressure-rupturing or chemically dissolving the topseal.

Methods such as high pressure cyclic steam injection are not appropriate for the present methods due to the risk of breaching the relatively thin artificial topseal with the injectant. Unlike in a deep reservoir, in a shallow reservoir the fracture pressure changes significantly from the bottom to top on a relative basis. There is a danger of a vertical fracture piercing to or through the artificial barrier, thereby defeating the utility of the topseal. Therefore, injection pressure is controlled so that the pressure at the top of a steam chamber stays below fracture pressure. The pressure at the top of a vapor-filled chamber will be similar to the pressure at the injection point due to the small hydrostatic head of gas.

The viscous hydrocarbon may have a viscosity greater than about 1,000 cp in its undisturbed *in situ* state. In one aspect, the viscous hydrocarbon comprises primarily bitumen. After substantial heating, the viscous hydrocarbon will have a viscosity well below 100 cp.

Figure 6 is a flowchart showing steps for a method 600 for recovering viscous hydrocarbons from a subsurface formation, in an alternate embodiment.

The method 600 includes locating a permeable subterranean zone geologically above the subsurface formation. This is shown at Box 610. In this instance, the subterranean zone is a permeable matrix such as sand.

The method 600 also includes injecting a polymer solution into the subterranean zone. This is provided at Box 620. The polymer solution is injected in a liquid phase, but sets as a solid or gel. In one aspect, the polymer solution is a cross-linked polymer solution that slowly reacts *in situ* to form a substantially solid material as the gel. The polymer solution spreads out over days or weeks within the subterranean zone. The polymer solution may be formed using a heavy brine to aid in spreading the polymer solution along the bitumen or viscous hydrocarbon interface. As an alternative to a polymer solution, the injectant may be a temperature-sensitive gelling fluid that cools within the subterranean zone 106 and hardens *in situ*.

The method 600 next includes allowing time for the polymer solution to gel within the subterranean zone. This is provided at Box 630. As the polymer solution gels, it forms an artificial topseal over the subsurface formation.

The method 600 also includes forming a plurality of heat injection wells into the subsurface formation. This is provided at Box 640. The heat injection wells are used to inject a heated vapor by any of the means mentioned above. The heated vapor may be steam, heated hydrocarbon solvent, or combinations thereof.

The method 600 further includes forming a plurality of producer wells into the subsurface formation. Each heat injection well has one or more associated producer wells, thereby creating sets of wells. This is seen at Box 650 of Figure 6. In one aspect, each of the heat injection wells is completed horizontally within the subsurface formation. In another aspect, each of the producer wells is completed horizontally within the subsurface formation. In one embodiment, each of the heat injection wells is completed horizontally within the subsurface formation and each of the producer wells is completed horizontally within the subsurface formation, such that each of the sets of wells is a pair of wells and each of the pairs of wells is completed substantially within a vertical plane.

The method 600 also includes injecting steam into each of the plurality of heat injection wells. This is presented in Box 660. The purpose is to heat the subsurface formation, thereby, (i) creating a steam chamber within the subsurface formation, (ii) reducing the viscosity of the viscous hydrocarbons, and (iii) mobilizing the viscous hydrocarbons into a readily-flowable heavy oil. The steam may include one or more hydrocarbon components, such as from the C₃ to C₁₀ range.

The method 600 additionally includes producing the heavy oil through each of the plurality of producer wells. This is presented in Box 670. In one aspect, the heavy oil flows gravitationally to the producer wells through the steam chamber and along an oil drainage layer formed naturally around the steam chamber.

The method 600 further includes adjusting the composition of the steam by increasing the solvent content before the steam chamber reaches the artificial topseal. This optional step is shown at Box 680. This step may be performed by increasing the hydrocarbon solvent content of the steam so that a light hydrocarbon solvent makes up at least 50% by volume of the steam. Alternatively, the light hydrocarbon solvent makes up at least 75% by volume of the steam. The solvent is preferably in the C₃ to C₅ range. The steam with solvent may condense at or near the interface with the artificial barrier.

The method 600 further includes decreasing the injection pressure of the steam into the subsurface formation after hydrocarbon production begins. This optional step is shown at Box 690.

As can be seen, methods are offered herein that provide improved processes for extracting hydrocarbons from a shallow subsurface formation containing bitumen or tar. The improved processes utilize *in situ* recovery that are preferable to mining since the processes may result in less surface disruption, permit deeper targets, have lower upfront capital expenses, and provide some *in situ* upgrading. In some embodiments, water usage is greatly reduced by using a hydrocarbon solvent rather than steam to reduce *in situ* oil viscosity. The choice of injectant, injection pressures and operating temperatures are judiciously chosen to be compatible with the artificial topseal.

While it will be apparent that the inventions herein described are well calculated to achieve the benefits and advantages set forth above, it will be appreciated that the inventions are susceptible to modification, variation and change. For example, the methods disclosed herein allow for the formation of an effective topseal over a hydrocarbon-bearing formation over an area that is at least five acres, and preferably at least about ten acres. The scope of the claims should not be limited by particular embodiments set forth herein, but should be construed in a manner consistent with the specification as a whole.

CLAIMS:

1. A method of recovering a viscous hydrocarbon, the viscous hydrocarbon having a viscosity, from a subsurface formation comprising:
 - injecting a barrier-forming fluid to create a horizontal artificial barrier to flow in a subterranean zone solely above or proximate a top of the subsurface formation, the horizontal artificial barrier being over an area that is at least about five acres (20,232 m²);
 - injecting a viscosity-reducing fluid into the subsurface formation at least until the viscosity-reducing fluid comes into contact with the horizontal artificial barrier and spreads horizontally across the horizontal artificial barrier so as to reduce the viscosity of the viscous hydrocarbon in at least a portion of the subsurface formation so as to mobilize the viscous hydrocarbon into a flowable heavy oil; and
 - applying gravity drainage to flow the flowable heavy oil to a production well.
2. The method of claim 1, wherein reducing the viscosity of the viscous hydrocarbon comprises heating the subsurface formation.
3. The method of claim 1, wherein reducing the viscosity of the viscous hydrocarbon comprises injecting a hydrocarbon solvent into the subsurface formation.
4. The method of claim 3, wherein the hydrocarbon solvent comprises components in a range from C₃ to C₁₀.
5. The method of claim 1, wherein the viscosity of the viscous hydrocarbon is greater than about 1,000 cp in its undisturbed *in situ* state.
6. The method of claim 5, wherein the viscous hydrocarbon comprises primarily bitumen.
7. The method of claim 1, wherein the horizontal artificial barrier is formed above and within about five meters of the top of the subsurface formation.
8. The method of claim 7, wherein:
 - injecting the viscosity-reducing fluid comprises heating the subsurface formation; and

heating the subsurface formation comprises forming a plurality of heat-supplying wells.

9. The method of claim 8, wherein each of the heat-supplying wells injects a heated fluid.

10. The method of claim 1, wherein the injected viscosity-reducing fluid is injected at a pressure no greater than about 300 psi above an initial reservoir pressure.

11. The method of claim 1, wherein the injected viscosity-reducing fluid is injected at a pressure no greater than about 100 psi above an initial reservoir pressure.

12. The method of claim 9, where the heated fluid comprises a vaporized fluid.

13. The method of claim 12, wherein the vaporized fluid comprises steam.

14. The method of claim 12, wherein the vaporized fluid further comprises a hydrocarbon solvent.

15. The method of claim 14, wherein the hydrocarbon solvent primarily comprises components in a range from C₃ to C₅.

16. The method of claim 14, wherein the hydrocarbon solvent condenses at initial *in situ* temperature conditions and *in situ* pressures.

17. The method of claim 8, further comprising:

forming the plurality of heat-supplying wells by forming heat injection wells which comprise forming first horizontal wells to serve as the heat injection wells; and

forming second horizontal wells to serve as production wells; and wherein:

the first and second wells form respective pairs of wells; and

the first and second wells are completed within a vertical plane.

18. The method of claim 7, wherein creating the horizontal artificial barrier comprises injecting a gelling fluid into the subterranean zone, the gelling fluid forming a gel within the subterranean zone after a period of setting.

19. The method of claim 18, wherein:
the gelling fluid is a polymer solution; and
the polymer solution is injected into the subterranean zone at a pressure below a fracture pressure of the subterranean zone.
20. The method of claim 19, wherein:
the polymer solution is a cross-linking polymer solution; and
the polymer solution forms the gel as a result of a chemical reaction *in situ*.
21. The method of claim 18, wherein:
the gelling fluid is a temperature-sensitive emulsion containing wax which at least partially solidifies after injection as a result of cooling *in situ*; and
the emulsion is injected into the subterranean zone.
22. The method of claim 7, further comprising:
injecting a fracturing fluid into the subterranean zone above a fracture pressure to form one or more horizontal fractures and fill the fractures with a barrier-forming substance.
23. The method of claim 22, wherein the fracturing fluid is a polymer solution, a clay slurry, or cement.
24. The method of claim 7, wherein creating the horizontal artificial barrier comprises injecting a fluid into the subterranean zone, the fluid precipitating solid particles within the subterranean zone and reducing formation permeability.
25. The method of claim 7, wherein creating the horizontal artificial barrier comprises:
completing a plurality of refrigerator wells in the subterranean zone;
circulating a cooling fluid through each of the plurality of refrigerator wells; and
causing water in the subterranean zone to substantially freeze *in situ*.
26. The method of claim 25, wherein each refrigerator well comprises:
an elongated tubular member for receiving the cooling fluid and for transporting the cooling fluid to the subterranean zone; and

a first expansion valve in fluid communication with the tubular member through which the cooling fluid flows.

27. The method of claim 25, further comprising:

chilling the cooling fluid below ambient air temperature prior to circulating the cooling fluid through each of the plurality of refrigerator wells.

28. The method of claim 1, wherein the horizontal artificial barrier is substantially continuous over at least 10 acres (40,464 m²).

29. A method of recovering a viscous hydrocarbon, the viscous hydrocarbon having a viscosity, from a subsurface formation comprising:

injecting a barrier-forming fluid to create a horizontal artificial barrier to flow in a subterranean zone solely above or proximate a top of the subsurface formation, the horizontal artificial barrier being over an area that is at least about five acres (20,232 m²);

injecting a viscosity-reducing fluid into the subsurface formation at least until the viscosity-reducing fluid comes into contact with the horizontal artificial barrier and spreads horizontally across the horizontal artificial barrier so as to reduce the viscosity of the viscous hydrocarbon in at least a portion of the subsurface formation so as to mobilize the viscous hydrocarbon into a flowable heavy oil; and

applying gravity drainage to flow the flowable heavy oil to a production well, wherein injecting the gelling fluid comprises flowing the gelling fluid down a wellbore, then flowing the gelling fluid into the subsurface formation from the wellbore, and then downwardly flowing the gelling fluid in the subterranean zone and spreading the gelling fluid over the viscous hydrocarbon proximate to only a top of the subsurface formation.

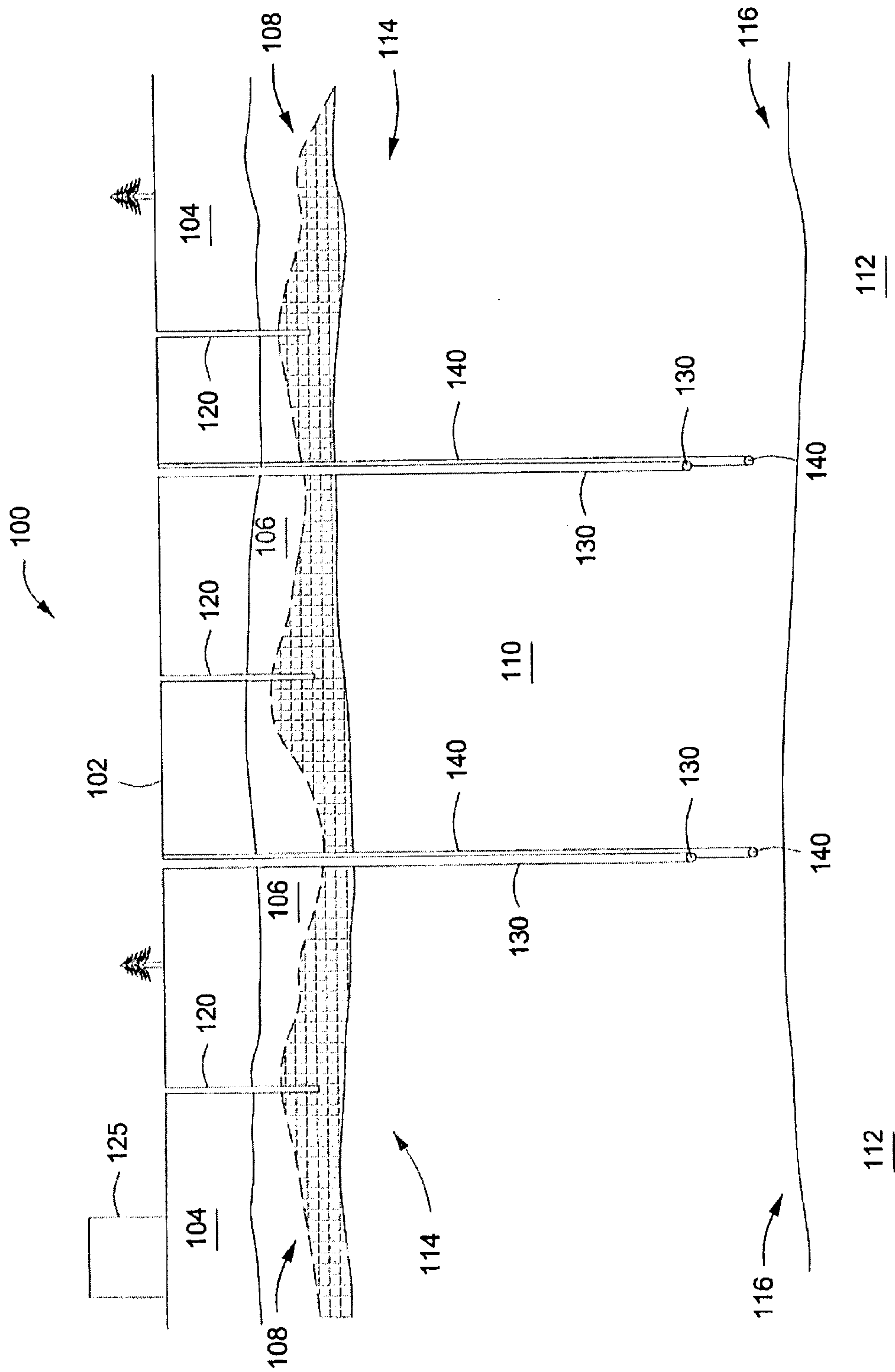


FIG. 1A

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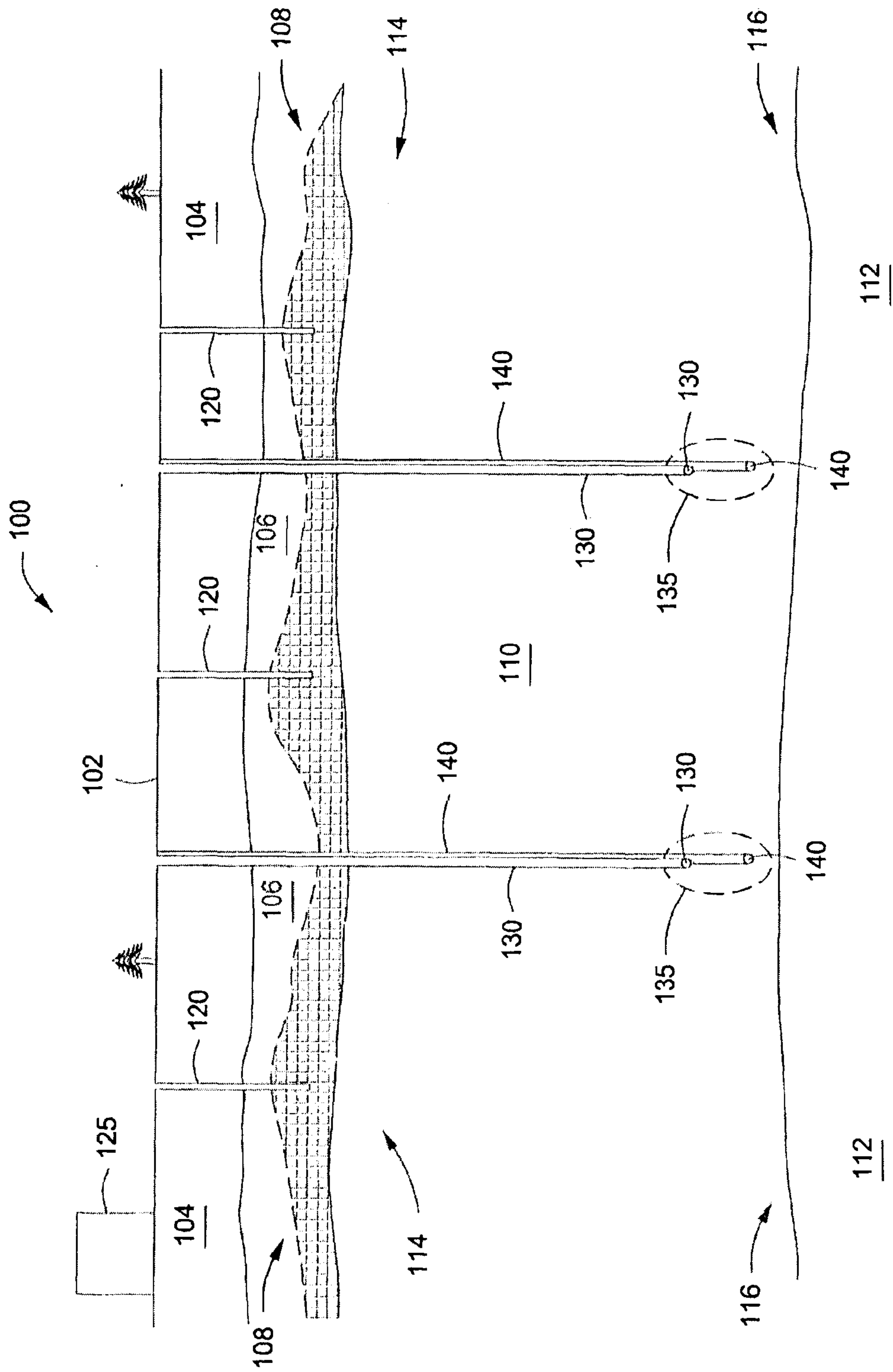


FIG. 1B

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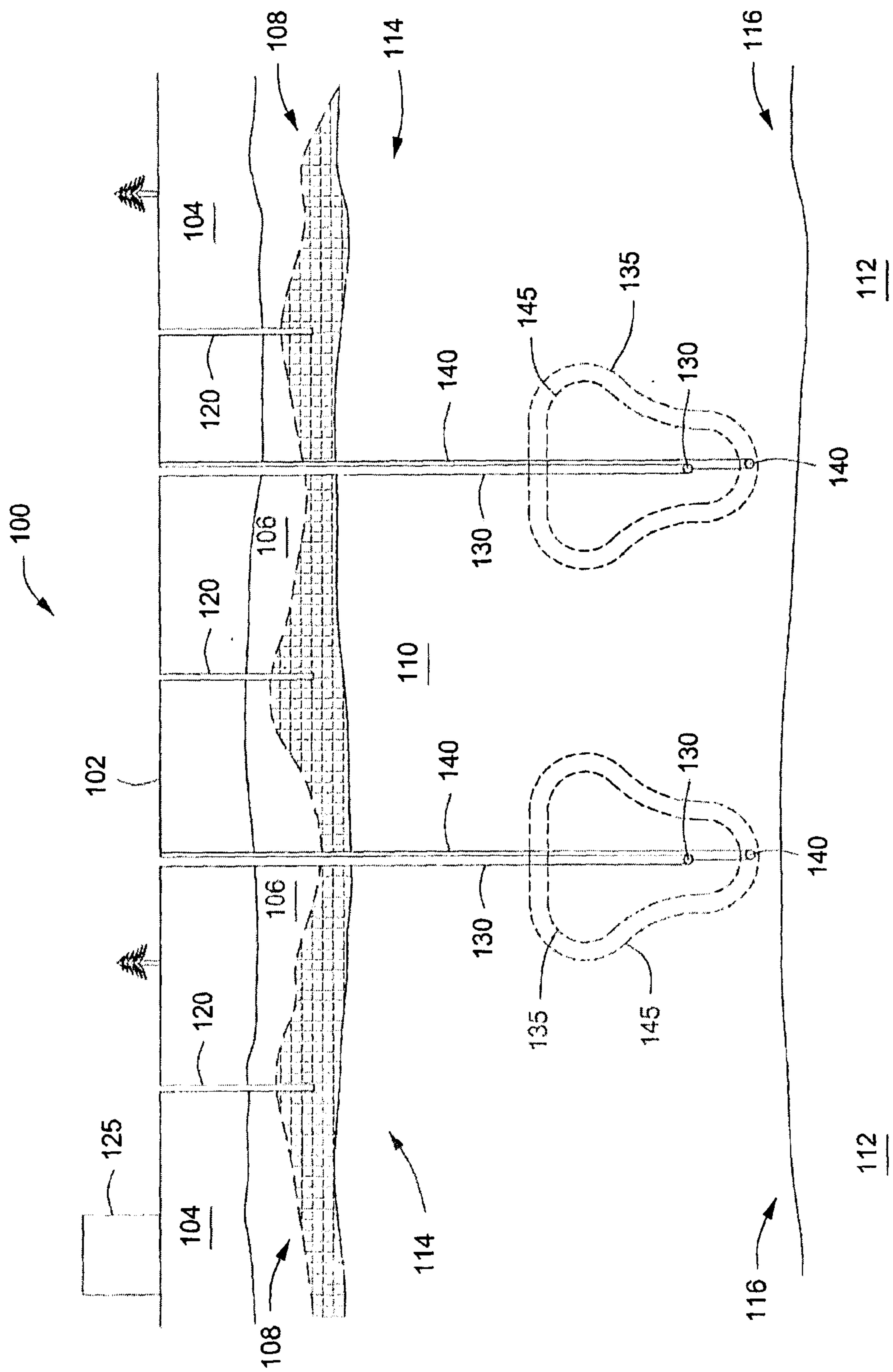


FIG. 1C

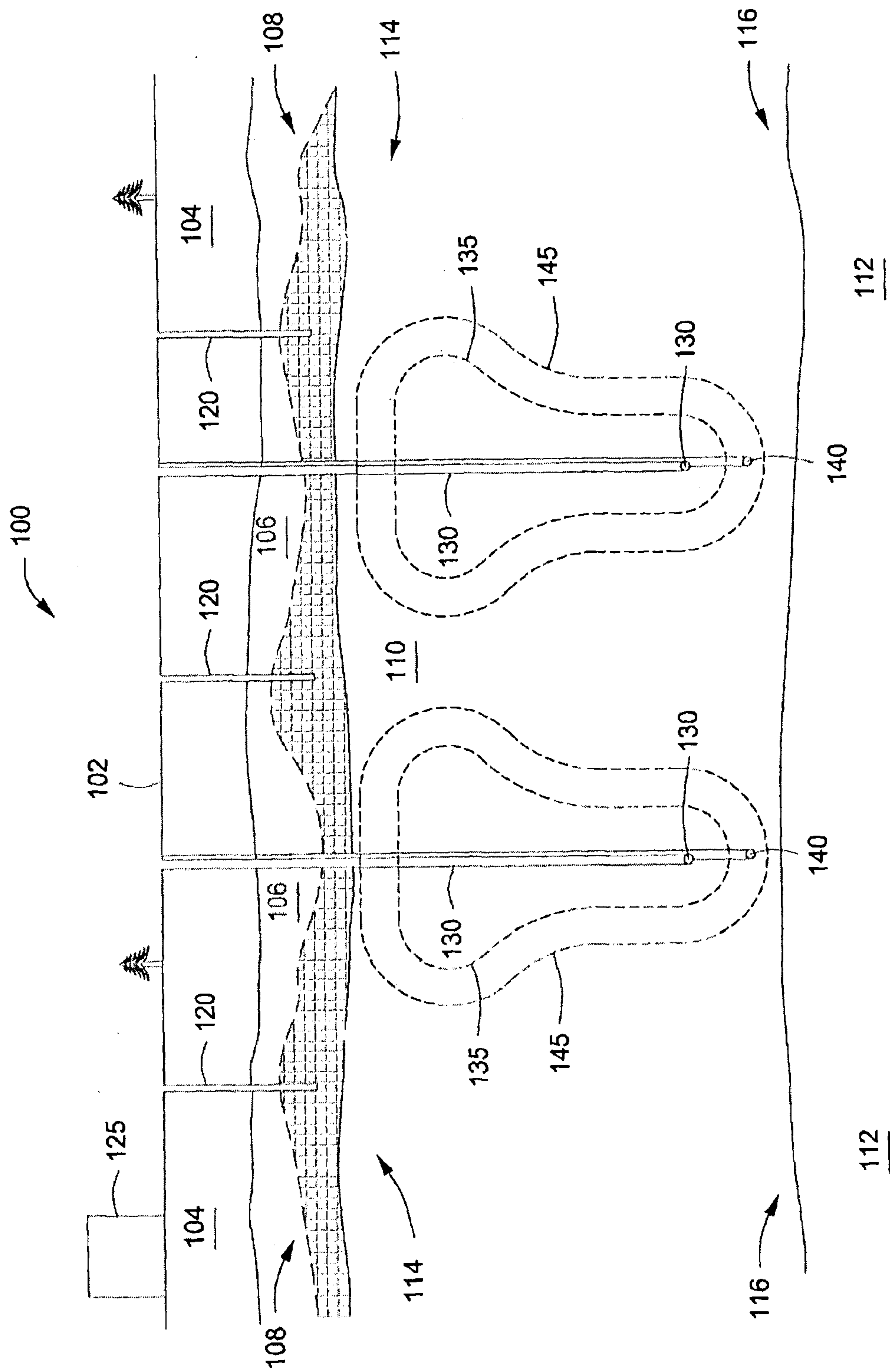


FIG. 1D

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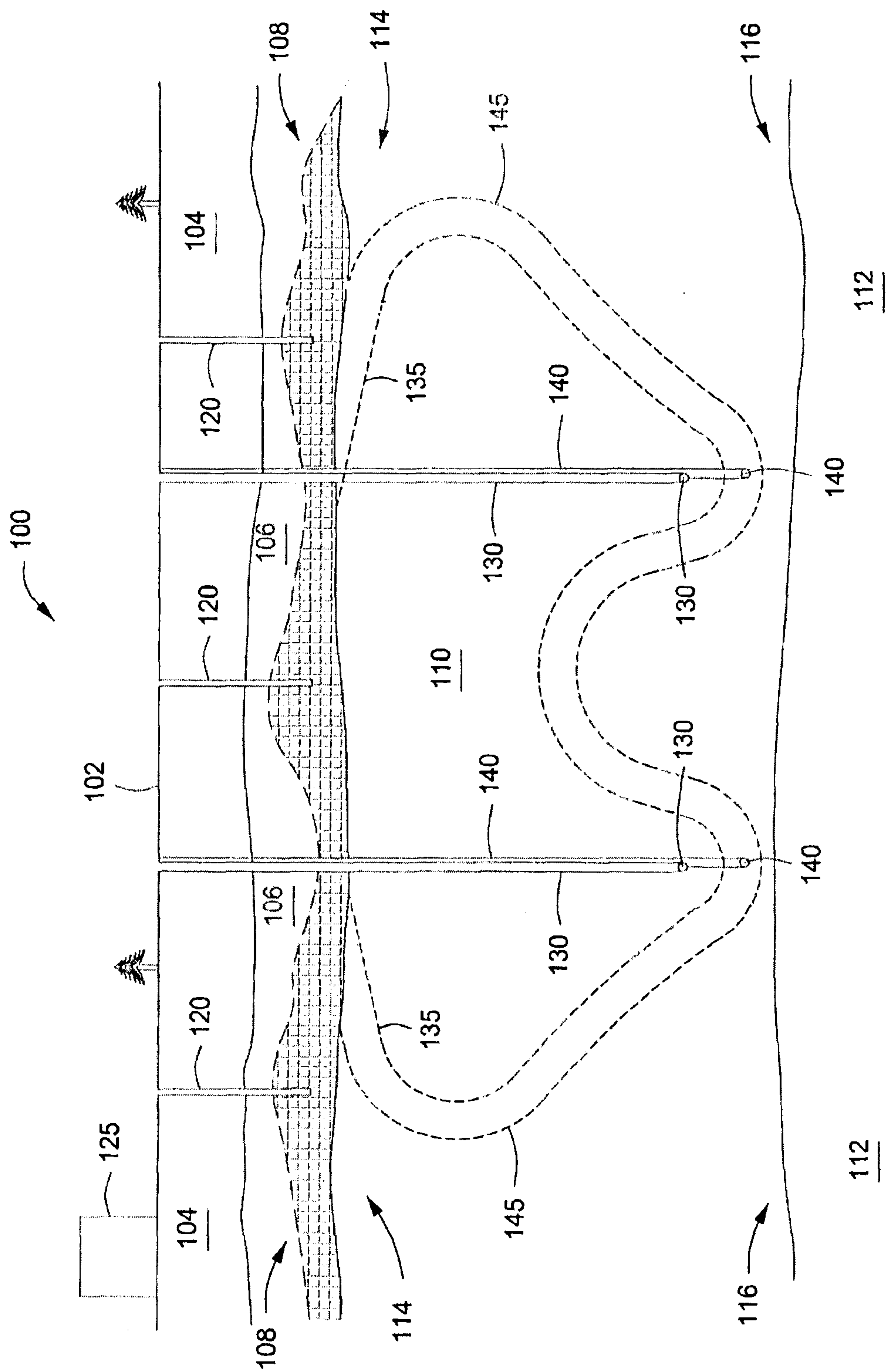


FIG. 1E

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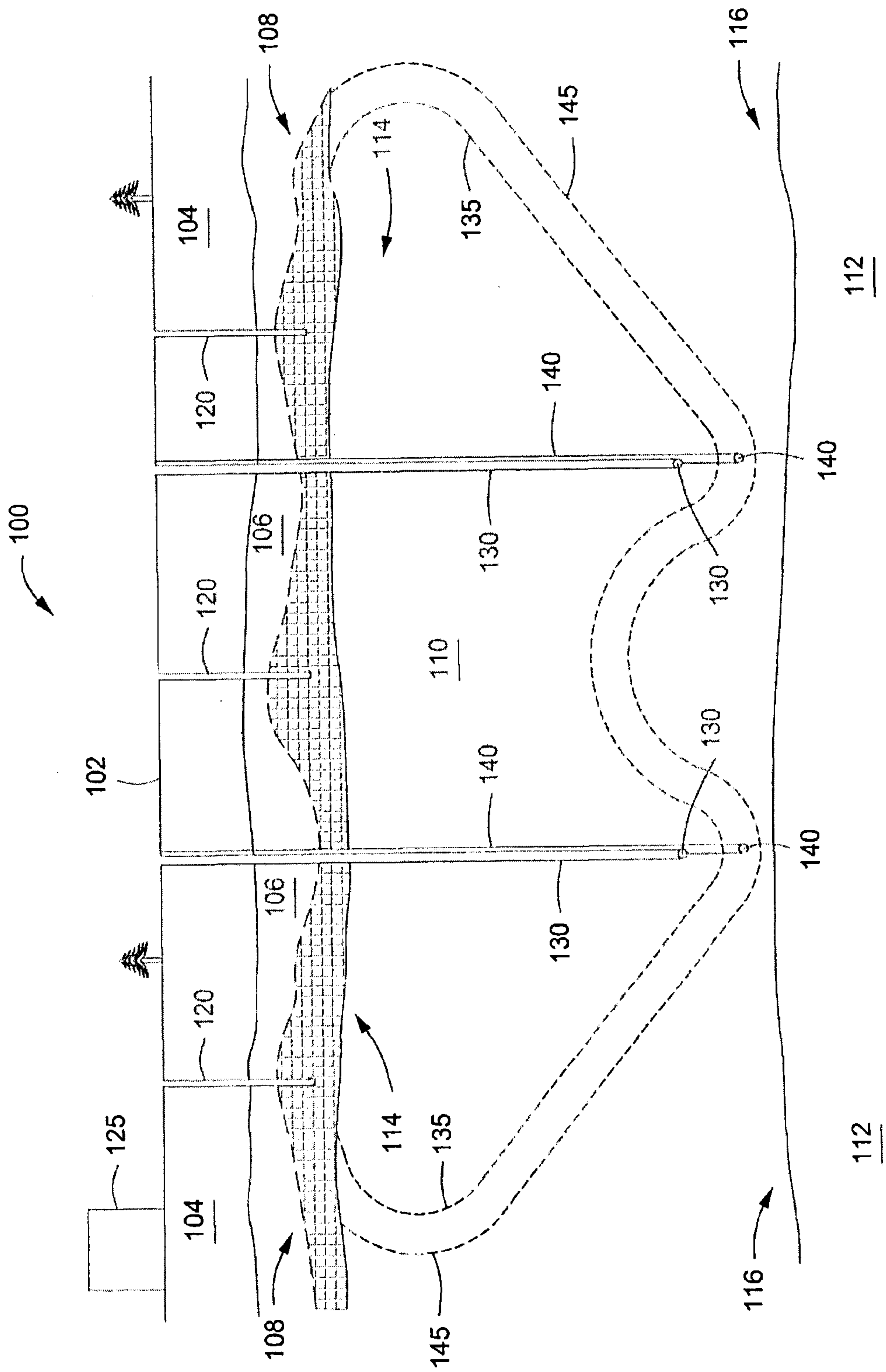


FIG. 1F

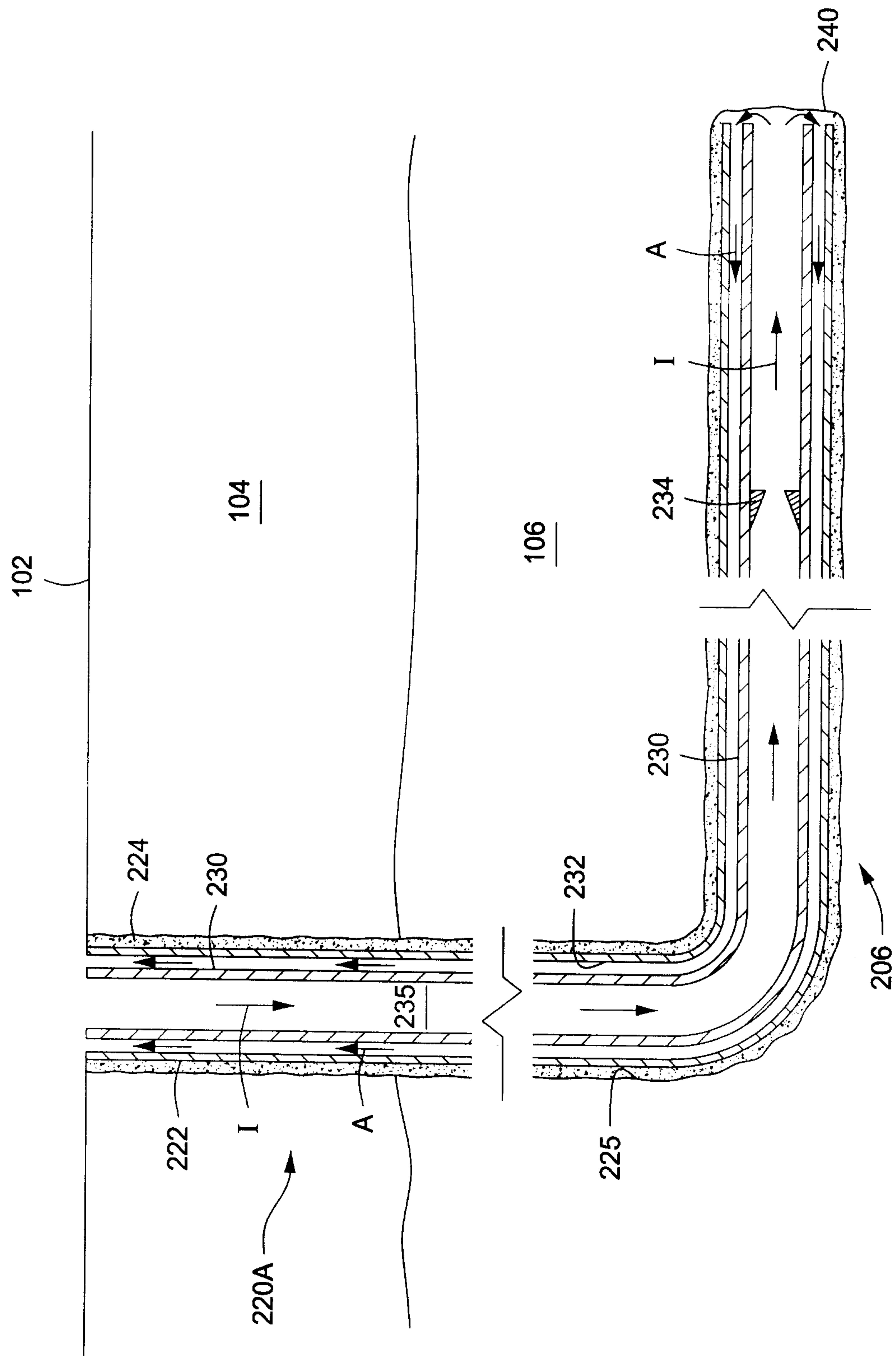


FIG. 2A

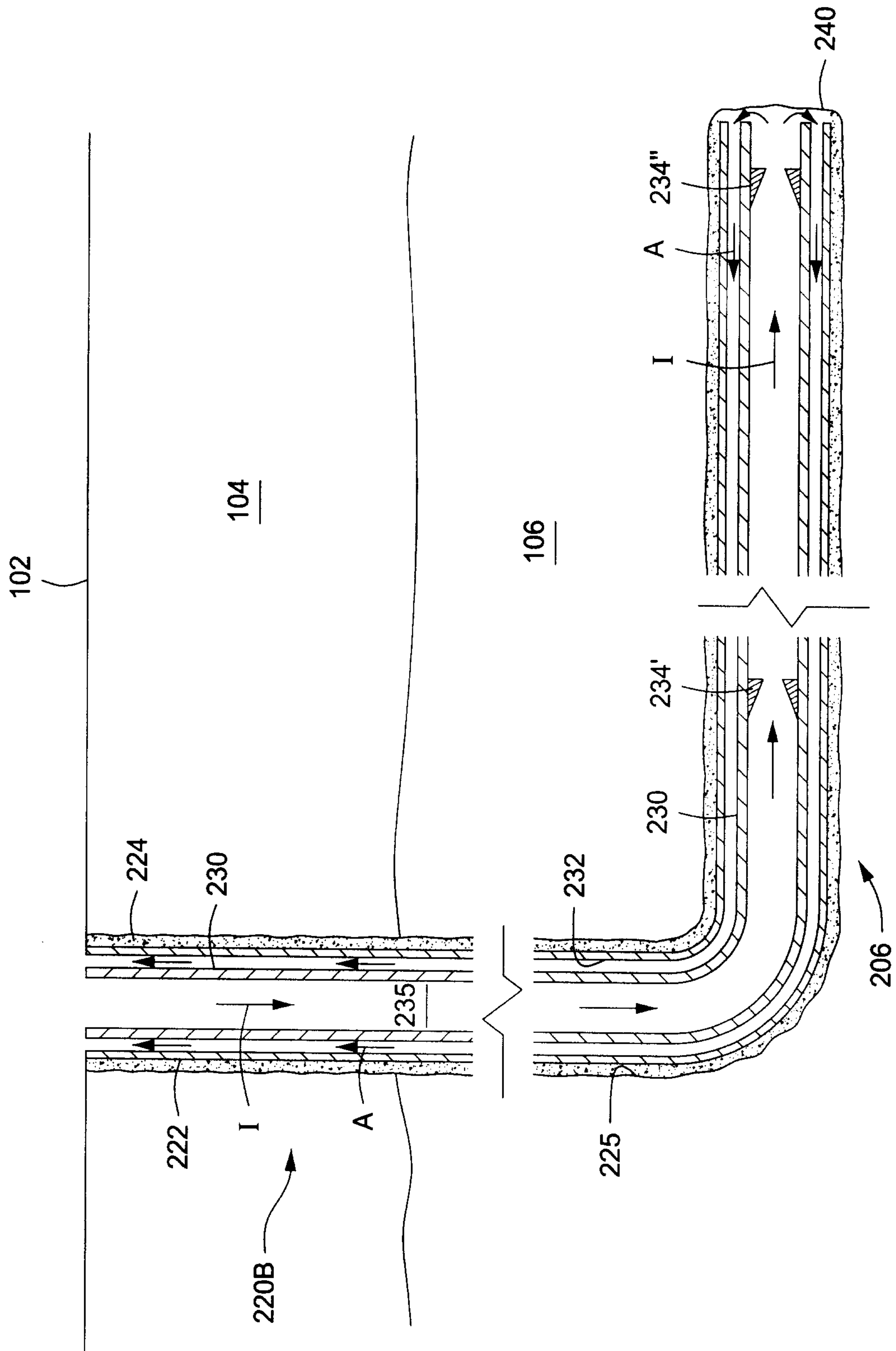
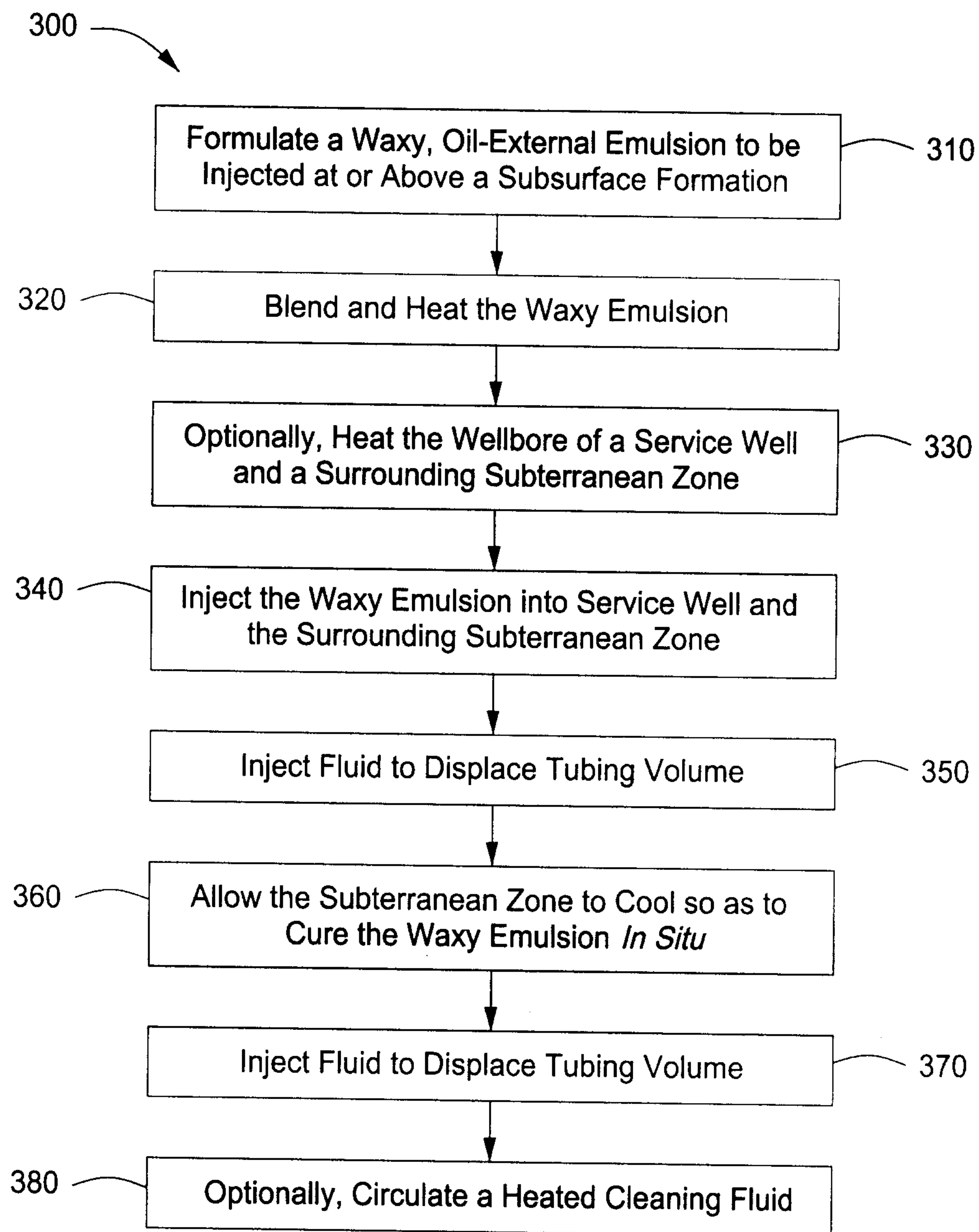


FIG. 2B

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**FIG. 3**

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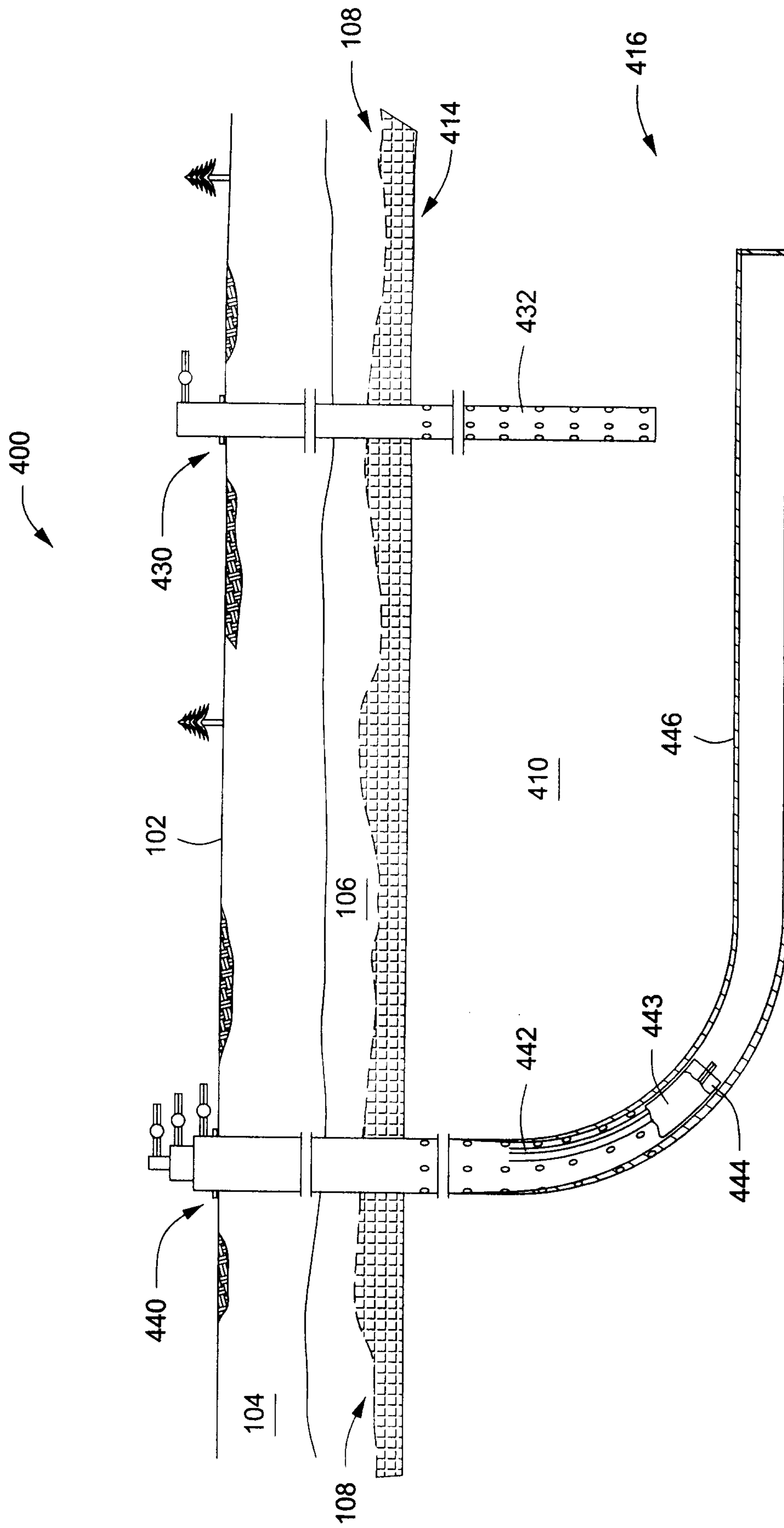
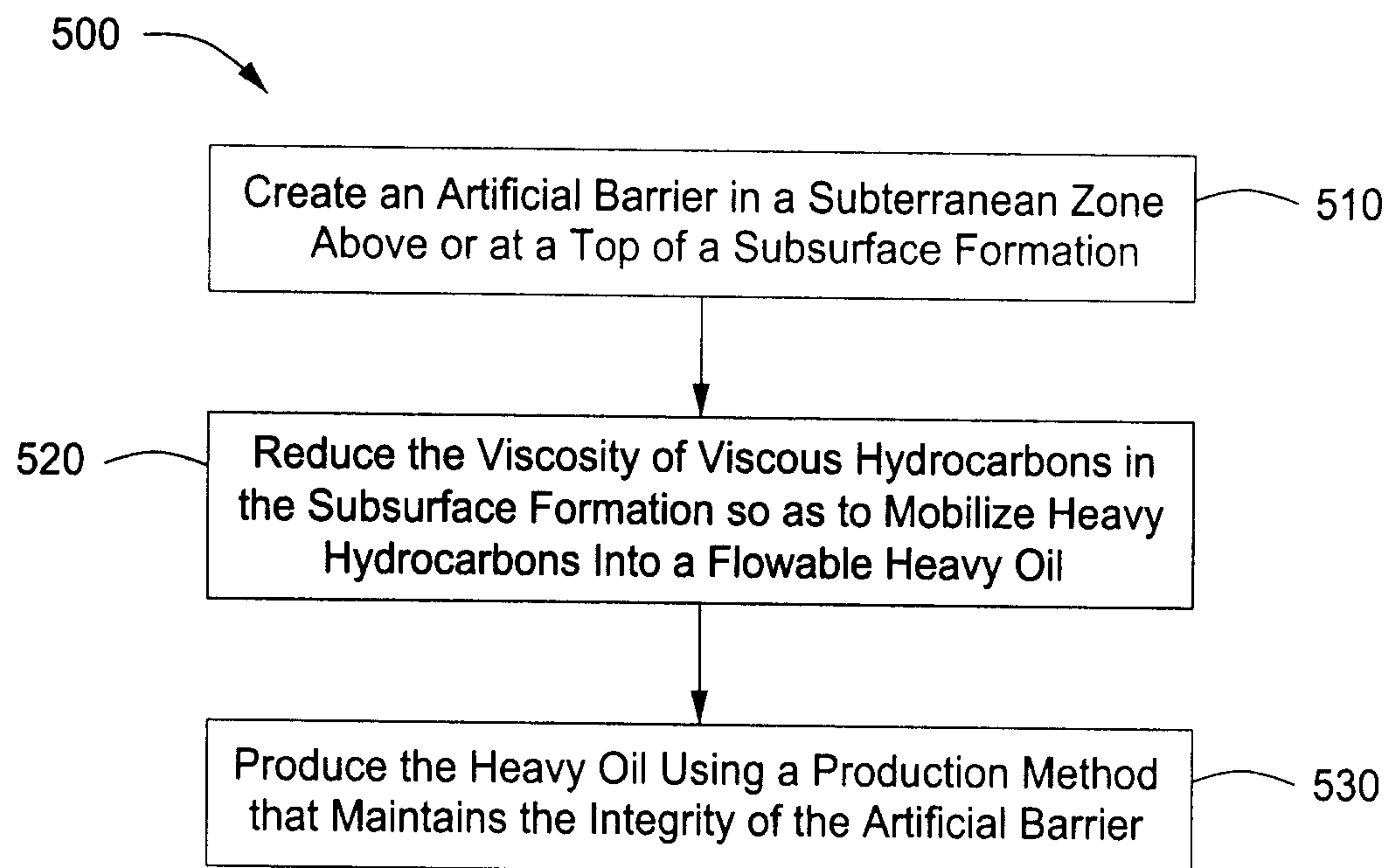
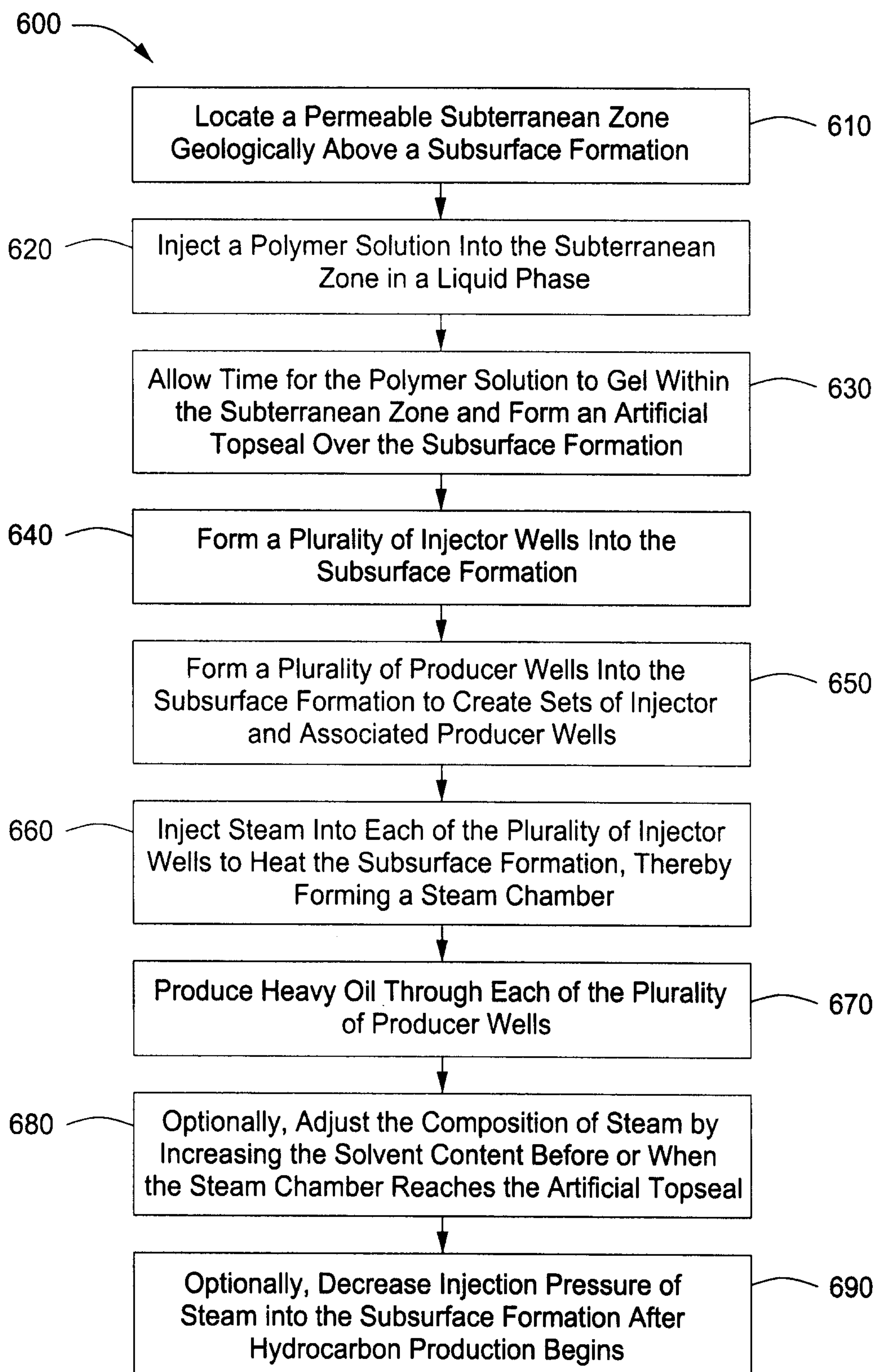


FIG. 4

11/12**FIG. 5**

12/12**FIG. 6**

