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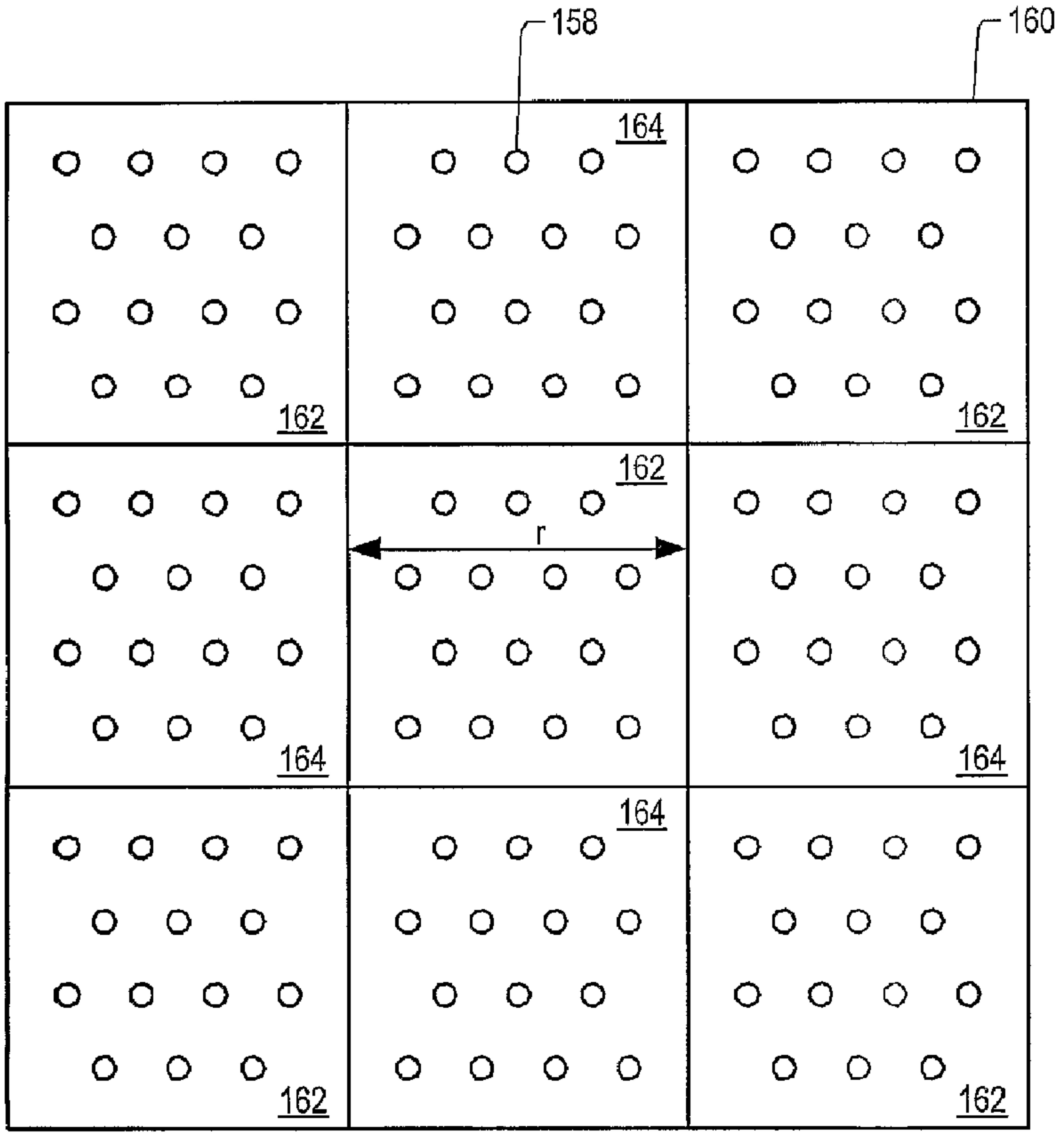
(54) **Titre** : CHAUFFAGE ETAGE ET/OU AVEC CONFIGURATION D'INJECTION LORS D'UN TRAITEMENT THERMIQUE IN SITU D'UNE FORMATION CONTENANT DES HYDROCARBURES

(54) **Title**: STAGED AND/OR PATTERNED HEATING DURING IN SITU THERMAL PROCESSING OF A HYDROCARBON CONTAINING FORMATION



(57) **Abrégé/Abstract**:

A method for treating a hydrocarbon containing formation is described. The method for treating a hydrocarbon containing formation may include heating a first volume (162) of the formation using a first set of heaters (158). A second volume (164) of the

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formation may be heated using a second set of heaters (158). The first volume may be spaced apart from the second volume by a third volume of the formation. The first volume, second volume, and/or third volume may be sized, shaped, and/or located to inhibit deformation of subsurface equipment caused by geomechanical motion of the formation during heating.

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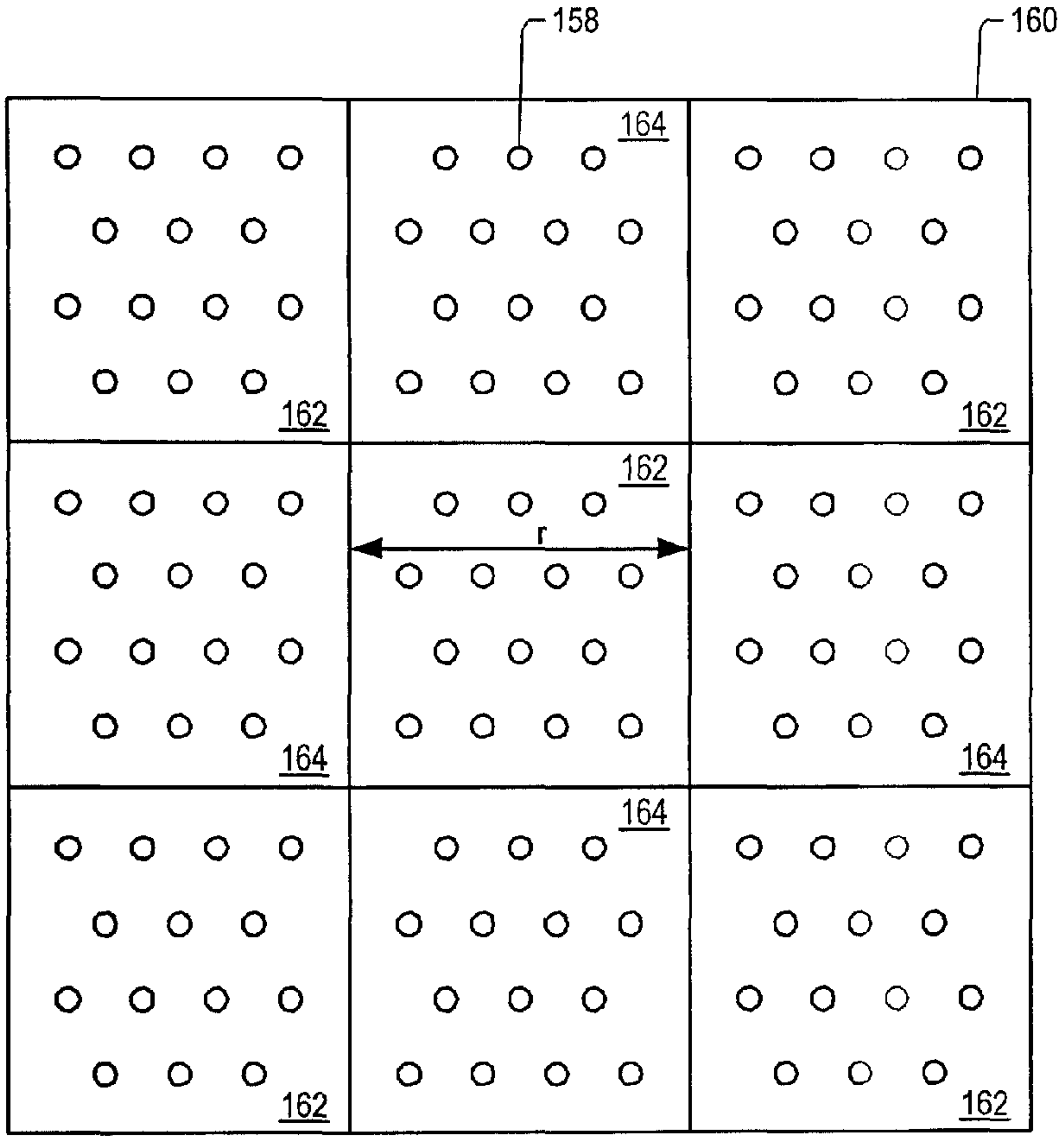

(57) Abstract: A method for treating a hydrocarbon containing formation is described. The method for treating a hydrocarbon containing formation may include heating a first volume (162) of the formation using a first set of heaters (158). A second volume (164) of the formation may be heated using a second set of heaters (158). The first volume may be spaced apart from the second volume by a third volume of the formation. The first volume, second volume, and/or third volume may be sized, shaped, and/or located to inhibit deformation of subsurface equipment caused by geomechanical motion of the formation during heating.

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STAGED AND/OR PATTERNED HEATING DURING IN SITU THERMAL PROCESSING OF A HYDROCARBON CONTAINING FORMATION

BACKGROUND

1. Field of the Invention

The present invention relates generally to methods and systems for production of hydrocarbons, hydrogen, and/or other products from hydrocarbon containing formations. Certain embodiments relate to staged and/or patterned heating during in situ treatment of hydrocarbon containing formations.

2. Description of Related Art

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

Application of heat to oil shale formations is described in U.S. Patent Nos. 2,923,535 to Ljungstrom and 4,886,118 to Van Meurs et al. Heat may be applied to the oil shale formation to pyrolyze kerogen within the oil shale formation. The heat may also fracture the formation to increase permeability of the formation. The increased permeability may allow formation fluid to travel to a production well where the fluid is removed from the oil shale formation. In some processes disclosed by Ljungstrom, for example, an oxygen containing gaseous medium is introduced to a permeable stratum, preferably while still hot from a preheating step, to initiate combustion.

Retorting processes for hydrocarbon containing formations may be generally divided into two major types: aboveground (surface) and underground (in situ). Aboveground retorting of a hydrocarbon containing formation typically involves mining and construction of metal vessels capable of withstanding high temperatures. The quality of oil produced from such retorting may typically be poor, thereby requiring costly upgrading. Aboveground retorting may also adversely affect environmental and water resources due to mining, transporting, processing, and/or disposing of the retorted material. Many U.S. patents have been issued relating to aboveground retorting of oil shale. Currently available aboveground retorting processes include, for example, direct, indirect, and/or combination heating methods.

In situ retorting typically involves retorting hydrocarbon containing formations without removing the hydrocarbon containing layers from the ground by mining. "Modified" in situ processes typically require some mining to develop underground retort chambers. An example of a "modified" in situ process includes a method developed by Occidental Petroleum that involves mining approximately 20% of the oil shale in a formation, explosively rubblizing the remainder of the oil shale to fill up the mined out area, and combusting the oil shale by gravity stable combustion in which combustion is initiated from the top of the retort. Other examples of "modified" in situ processes include the "Rubble In Situ Extraction" ("RISE") method developed by the Lawrence Livermore Laboratory ("LLL") and radio-frequency methods developed by IIT Research Institute ("IITRI") and LLL, which involve tunneling and mining drifts to install an array of radio-frequency antennas in an oil shale formation.

Obtaining permeability within a hydrocarbon containing formation (e.g., between injection and production wells) tends to be difficult because hydrocarbon containing formations may be substantially impermeable. Many methods have attempted to link injection and production wells, including: hydraulic fracturing such as methods investigated by Dow Chemical and Laramie Energy Research Center; electrical fracturing (e.g., by methods investigated by Laramie Energy Research Center); acid leaching of limestone cavities (e.g., by methods investigated by Dow Chemical); steam injection into permeable nahcolite zones to dissolve the nahcolite (e.g., by methods investigated by Shell Oil and Equity Oil); fracturing with chemical explosives (e.g., by methods investigated by Talley Energy Systems); fracturing with nuclear explosives (e.g., by methods investigated by Project Bronco); and combinations of these methods. Many of such methods, however, have relatively high operating costs and lack sufficient injection capacity.

An example of an in situ retorting process is illustrated in U.S. Patent No. 3,241,611 to Dougan, assigned to Equity Oil Company. For example, Dougan discloses a method involving the use of natural gas for conveying kerogen-decomposing heat to the formation. The heated natural gas may be used as a solvent for thermally decomposed kerogen. The heated natural gas exercises a solvent-stripping action with respect to the oil shale by penetrating pores that exist in the shale. The natural gas carrier fluid, accompanied by decomposition product vapors and gases, passes upwardly through extraction wells into product recovery lines, and into and through condensers interposed in such lines, where the decomposition vapors condense, leaving the natural gas carrier fluid to flow through a heater and into an injection well drilled into the deposit of oil shale.

As outlined above, there has been a significant amount of effort to develop methods and systems to economically produce hydrocarbons, hydrogen, and/or other products from hydrocarbon containing formations. At present, however, there are still many hydrocarbon containing formations from which hydrocarbons, hydrogen, and/or other products cannot be economically produced. Thus, there is still a need for improved methods and systems for production of hydrocarbons, hydrogen, and/or other products from various hydrocarbon containing formations.

SUMMARY

In an embodiment, a method for treating a hydrocarbon containing formation may include heating a first volume of the formation using a first set of heaters. A second volume of the formation may be heated using a second set of heaters. The first volume may be spaced apart from the second volume by a third volume of the formation. The first volume, second volume, and/or third volume may be sized, shaped, and/or located to inhibit deformation of subsurface equipment caused by geomechanical motion of the formation during heating.

In another embodiment, the invention relates to a method for treating a hydrocarbon containing formation, comprising: heating a first volume of the formation using a first set of heaters; heating a second volume of the formation using a second set of heaters, wherein the first volume is spaced apart from the second volume by a third volume of the formation; heating the third volume using a third set of heaters, wherein the third set of heaters begins heating at a selected time after the first set of heaters and the second set of heaters; allowing the heat to transfer from the first volume, the second volume, and the third volume of the formation to at least a part of the formation; and producing a mixture from the formation.

In yet another embodiment, the invention relates to a method for treating a hydrocarbon containing formation, comprising: heating a first volume of the formation using a first set of heaters; and heating a second volume of the formation using a second set of heaters, wherein the first volume is spaced apart from the second volume by a third volume of the formation; and sizing, shaping, and/or locating the first volume, the second volume, and the third volume to inhibit deformation of subsurface equipment caused by geomechanical motion of the formation during heating.

BRIEF DESCRIPTION OF THE DRAWINGS

Advantages of the present invention may become apparent to those skilled in the art with the benefit of the following detailed description of the preferred embodiments and upon reference to the accompanying drawings in which:

FIG. 1 depicts an illustration of stages of heating a hydrocarbon containing formation.

FIG. 2 shows a schematic view of an embodiment of a portion of an in situ conversion system for treating a hydrocarbon containing formation.

FIG. 3 depicts an embodiment of a heater in an open wellbore of a hydrocarbon containing formation with a rich layer.

FIG. 4 depicts an embodiment of a heater in an open wellbore of a hydrocarbon containing formation with an expanded rich layer.

FIG. 5 depicts calculations of wellbore radius change versus time for heating in an open wellbore.

FIG. 6 depicts calculations of wellbore radius change versus time for heating in an open wellbore.

FIG. 7 depicts an embodiment of a heater in an open wellbore of a hydrocarbon containing formation with an expanded wellbore proximate a rich layer.

FIG. 8 depicts an embodiment of a heater in an open wellbore with a liner placed in the opening.

FIG. 9 depicts an embodiment of a heater in an open wellbore with a liner placed in the opening and the formation expanded against the liner.

FIG. 10 depicts maximum stress and hole size versus richness for calculations of heating in an open wellbore.

FIG. 11 depicts an embodiment of a plan view of a pattern of heaters for heating a hydrocarbon containing formation.

FIG. 12 depicts an embodiment of a plan view of a pattern of heaters for heating a hydrocarbon containing formation.

FIG. 13 depicts radial stress and liner collapse strength versus remaining downhole diameter and liner outside diameter.

FIG. 14 depicts radial stress and conduit collapse strength versus a ratio of conduit outside diameter to initial wellbore diameter in a hydrocarbon containing formation.

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

DETAILED DESCRIPTION

The following description generally relates to systems and methods for treating a hydrocarbon containing formation. Such formations may be treated to yield relatively high quality hydrocarbon products, hydrogen, and other products.

"Hydrocarbons" are generally defined as molecules formed primarily by carbon and hydrogen atoms. Hydrocarbons may also include other elements, such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur. Hydrocarbons may be, but are not limited to, kerogen, bitumen, pyrobitumen, oils, natural mineral waxes, and asphaltites. Hydrocarbons may be located within or adjacent to mineral matrices within the earth. Matrices may include, but are not limited to, sedimentary rock, sands, silicilytes, carbonates, diatomites, and other porous media. "Hydrocarbon fluids" are fluids that include hydrocarbons. Hydrocarbon fluids may include, entrain, or be entrained in non-hydrocarbon fluids (e.g., hydrogen ("H_2"), nitrogen ("N_2"), carbon monoxide, carbon dioxide, hydrogen sulfide, water, and ammonia).

A "formation" includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. An "overburden" and/or an "underburden" includes one or more different types of 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 embodiments of in situ conversion processes, an overburden and/or an underburden may include a hydrocarbon containing layer or hydrocarbon containing layers that are relatively impermeable and are not subjected to temperatures during in situ conversion processing that results in significant characteristic changes of the hydrocarbon containing layers of the overburden and/or underburden. For example, an underburden may contain shale or mudstone. In some cases, the overburden and/or underburden may be somewhat permeable.

"Kerogen" is a solid, insoluble hydrocarbon that has been converted by natural degradation (e.g., by diagenesis) and that principally contains carbon, hydrogen, nitrogen, oxygen, and sulfur. Hydrocarbon containing formation may contain kerogens. "Bitumen" is a non-crystalline solid or viscous hydrocarbon material that is substantially soluble in carbon disulfide. "Oil" is a fluid containing a mixture of condensable hydrocarbons.

The terms "formation fluids" and "produced fluids" refer to fluids removed from a hydrocarbon containing formation and may include pyrolyzation fluid, synthesis gas, mobilized hydrocarbon, and water (steam). The term "mobilized fluid" refers to fluids within the formation that are able to flow because of thermal treatment of the formation. Formation fluids may include hydrocarbon fluids as well as non-hydrocarbon fluids.

"Carbon number" refers to a number of carbon atoms within a molecule. A hydrocarbon fluid may include various hydrocarbons having varying numbers of carbon atoms. The hydrocarbon fluid may be described by a carbon number distribution. Carbon numbers and/or carbon number distributions may be determined by true boiling point distribution and/or gas-liquid chromatography.

A "heat source" is any system for providing heat to at least a portion of a formation substantially by conductive and/or radiative heat transfer. For example, a heat source may include electric heaters such as an insulated conductor, an elongated member, and/or a conductor disposed within a conduit. A heat source may also include heat sources that generate heat by burning a fuel external to or within a formation, such as surface burners, downhole gas burners, flameless distributed combustors, and natural distributed combustors. A heat source may also include a heater that may provide heat to a zone proximate and/or surrounding a heating location such as a heater well.

A "heater" is any system for generating heat in a well or a near wellbore region. Heaters may be, but are not limited to, electric heaters, burners, combustors (e.g., natural distributed combustors) that react with material in or produced from a formation, and/or combinations thereof. A "unit of heat sources" refers to a number of heat sources that form a template that is repeated to create a pattern of heat sources within a formation.

The term "wellbore" refers to a hole in a formation made by drilling or insertion of a conduit into the formation. A wellbore may have a substantially circular cross section, or other cross-sectional shapes (e.g., circles, ovals, squares, rectangles, triangles, slits, or other regular or irregular shapes). As used herein, the terms "well" and "opening," when referring to an opening in the formation may be used interchangeably with the term "wellbore."

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

"Pyrolyzation fluids" or "pyrolysis products" refers to fluid produced substantially during pyrolysis of hydrocarbons. Fluid produced by pyrolysis reactions may mix with other fluids in a formation. The mixture would be considered pyrolyzation fluid or pyrolyzation product. As used herein, "pyrolysis zone" refers to a volume of a formation that is reacted or reacting to form a pyrolyzation fluid.

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

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

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

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

Hydrocarbons in formations may be treated in various ways to produce many different products. In certain embodiments, such formations may be treated in stages. FIG. 1 illustrates several stages of heating a hydrocarbon containing formation. FIG. 1 also depicts an example of yield (barrels of oil equivalent per ton) (y axis) of formation fluids from a hydrocarbon containing formation versus temperature (°C) (x axis) of the formation.

Desorption of methane and vaporization of water occurs during stage 1 heating. Heating of the formation through stage 1 may be performed as quickly as possible. For example, when a hydrocarbon containing formation is initially heated, hydrocarbons in the formation may desorb adsorbed methane. The desorbed methane may be produced from the formation. If the hydrocarbon containing formation is heated further, water within the hydrocarbon containing formation may be vaporized. Water may occupy, in some hydrocarbon containing formations, between about 10% to about 50% of the pore volume in the formation. In other formations, water may occupy larger or smaller portions of the pore volume. Water typically is vaporized in a formation between about 160 °C and about 285 °C for pressures of about 6 bars absolute to 70 bars absolute. In some embodiments, the vaporized water may produce wettability changes in the formation and/or increase formation pressure. The wettability changes and/or increased pressure may affect pyrolysis reactions or other reactions in the formation. In certain embodiments, the vaporized water may be produced from the formation. In other embodiments, the vaporized water may be used for steam extraction and/or distillation in the formation or outside the formation. Removing the water from and increasing the pore volume in the formation may increase the storage space for hydrocarbons within the pore volume.

After stage 1 heating, the formation may be heated further, such that a temperature within the formation reaches (at least) an initial pyrolyzation temperature (e.g., a temperature at the lower end of the temperature range shown as stage 2). Hydrocarbons within the formation may be pyrolyzed throughout stage 2. A pyrolysis temperature range may vary depending on types of hydrocarbons within the formation. A pyrolysis temperature range may include temperatures between about 250 °C and about 900 °C. A pyrolysis temperature range for producing desired products may extend through only a portion of the total pyrolysis temperature range. In some embodiments, a pyrolysis temperature range for producing desired products may include temperatures between about 250 °C to about 400 °C. If a temperature of hydrocarbons in a formation is slowly raised through a temperature range from about 250 °C to about 400 °C, production of pyrolysis products may be substantially complete when the temperature approaches 400 °C. Heating the hydrocarbon containing formation with a plurality of heat sources may establish thermal gradients around the heat sources that slowly raise the temperature of hydrocarbons in the formation through a pyrolysis temperature range.

In some in situ conversion embodiments, a temperature of the hydrocarbons to be subjected to pyrolysis may not be slowly increased throughout a temperature range from about 250 °C to about 400 °C. The hydrocarbons in the formation may be heated to a desired temperature (e.g., about 325 °C). Other temperatures may be selected as the desired temperature. Superposition of heat from heat sources may allow the desired temperature to be relatively quickly and efficiently established in the formation. Energy input into the formation from the heat sources may be adjusted to maintain the temperature in the formation substantially at the desired temperature. The hydrocarbons may be maintained substantially at the desired temperature until pyrolysis declines such that production of desired formation fluids from the formation becomes uneconomical. Parts of a formation that are subjected to pyrolysis may include regions brought into a pyrolysis temperature range by heat transfer from only one heat source.

Formation fluids including pyrolyzation fluids may be produced from the formation. The pyrolyzation fluids may include, but are not limited to, hydrocarbons, hydrogen, carbon dioxide, carbon monoxide, hydrogen sulfide, ammonia, nitrogen, water, and mixtures thereof. As the temperature of the formation increases, the amount of condensable hydrocarbons in the produced formation fluid tends to decrease. At high temperatures, the formation may produce mostly methane and/or hydrogen. If a hydrocarbon containing formation is heated throughout an entire pyrolysis range, the formation may produce only small amounts of hydrogen towards an upper limit of the pyrolysis range. After all of the available hydrogen is depleted, a minimal amount of fluid production from the formation will typically occur.

After pyrolysis of hydrocarbons, a large amount of carbon and some hydrogen may still be present in the formation. A significant portion of remaining carbon in the formation can be produced from the formation in the form of synthesis gas. Synthesis gas generation may take place during stage 3 heating depicted in FIG. 1. Stage 3 may include heating a hydrocarbon containing formation to a temperature sufficient to allow synthesis gas generation. For example, synthesis gas may be produced within a temperature range from about 400 °C to about 1200 °C. The temperature of the formation when the synthesis gas generating fluid is introduced to the formation may determine the composition of synthesis gas produced within the formation. If a synthesis gas generating fluid is introduced into a formation at a temperature sufficient to allow synthesis gas generation, synthesis gas may be generated within the formation. The generated synthesis gas may be removed from the formation through a production well or production wells. A large volume of synthesis gas may be produced during generation of synthesis gas.

Total energy content of fluids produced from a hydrocarbon containing formation may stay relatively constant throughout pyrolysis and synthesis gas generation. During pyrolysis at relatively low formation temperatures, a significant portion of the produced fluid may be condensable hydrocarbons that have a high energy content. At higher pyrolysis temperatures, however, less of the formation fluid may include condensable hydrocarbons. More non-condensable formation fluids may be produced from the formation. Energy content per unit volume of the produced fluid may decline slightly during generation of predominantly non-condensable formation fluids. During synthesis gas generation, energy content per unit volume of produced synthesis gas declines significantly compared to energy content of pyrolyzation fluid. The volume of the produced synthesis gas, however, will in many instances increase substantially, thereby compensating for the decreased energy content.

Each hydrocarbon containing layer of a formation may have a potential formation fluid yield or richness. The richness of a hydrocarbon layer may vary in a hydrocarbon layer and between different hydrocarbon layers in a formation. Richness may depend on many factors including the conditions under which the hydrocarbon containing layer was formed, an amount of hydrocarbons in the layer, and/or a composition of hydrocarbons in the layer. Richness of a hydrocarbon layer may be estimated in various ways. For example, richness may be measured by a Fischer Assay. The Fischer Assay is a standard method which involves heating a sample of a hydrocarbon containing layer to approximately 500 °C in one hour, collecting products produced from the heated sample, and quantifying the amount of products produced. A sample of a hydrocarbon containing layer may be obtained from a hydrocarbon containing formation by a method such as coring or any other sample retrieval method.

An in situ conversion process may be used to treat formations with hydrocarbon layers that have thicknesses greater than about 10 m. Thick formations may allow for placement of heat sources so that superposition of heat from the heat sources efficiently heats the formation to a desired temperature. Formations having hydrocarbon layers that are less than 10 m thick may also be treated using an in situ conversion process. In some in situ conversion embodiments of thin hydrocarbon layer formations, heat sources may be inserted in or adjacent to the hydrocarbon layer along a length of the hydrocarbon layer (e.g., with horizontal or directional drilling). Heat losses to layers above and below the thin hydrocarbon layer or thin hydrocarbon layers may be offset by an amount and/or quality of fluid produced from the formation.

FIG. 2 shows a schematic view of an embodiment of a portion of an in situ conversion system for treating a hydrocarbon containing formation. Heat sources 108 may be placed within at least a portion of the hydrocarbon containing formation. Heat sources 108 may include, for example, electric heaters such as insulated conductors, conductor-in-conduit heaters, surface burners, flameless distributed combustors, and/or natural distributed combustors. Heat sources 108 may also include other types of heaters. Heat sources 108 may provide heat to at least a portion of a hydrocarbon containing formation. Energy may be supplied to the heat sources 108 through supply lines 110. Supply lines 110 may be structurally different depending on the type of heat source or heat sources being used to heat the formation. Supply lines 110 for heat sources may transmit electricity for electric heaters, may transport fuel for combustors, or may transport heat exchange fluid that is circulated within the formation.

Production wells 112 may be used to remove formation fluid from the formation. Formation fluid produced from production wells 112 may be transported through collection piping 114 to treatment facilities 116. Formation fluids may also be produced from heat sources 108. For example, fluid may be produced from heat sources 108 to control pressure within the formation adjacent to the heat sources. Fluid produced from heat sources 108 may be transported through tubing or piping to collection piping 114 or the produced fluid may be transported through tubing or piping directly to treatment facilities 116. Treatment facilities 116 may include separation units, reaction units, upgrading units, fuel cells, turbines, storage vessels, and other systems and units for processing produced formation fluids.

An in situ conversion system for treating hydrocarbons may include barrier wells 118. Barrier wells may be used to form a barrier around a treatment area. The barrier may inhibit fluid flow into and/or out of the treatment area. Barrier wells may be, but are not limited to, dewatering wells (vacuum wells), capture wells, injection wells, grout wells, or freeze wells. In some embodiments, barrier wells 118 may be dewatering wells. Dewatering wells may remove liquid water and/or inhibit liquid water from entering a portion of a hydrocarbon containing formation to be heated, or to a formation being heated. A plurality of water wells may surround all or a portion of a formation to be heated. In the embodiment depicted in FIG. 2, the dewatering wells are shown extending only along one side of heat sources 108, but dewatering wells typically encircle all heat sources 108 used, or to be used, to heat the formation.

As shown in FIG. 2, in addition to heat sources 108, one or more production wells 112 will typically be placed within the portion of the hydrocarbon containing formation. Formation fluids may be produced through production well 112. In some embodiments, production well 112 may include a heat source. The heat source may heat the portions of the formation at or near the production well and allow for vapor phase removal of formation fluids. The need for high temperature pumping of liquids from the production well may be reduced or eliminated. Avoiding or limiting high temperature pumping of liquids may significantly decrease production costs. Providing heating at or through the production well may: (1) inhibit condensation and/or refluxing of production fluid when such production fluid is moving in the production well proximate the overburden, (2) increase heat input into the formation, and/or (3) increase formation permeability at or proximate the production well. In some in situ conversion process embodiments, an amount of heat supplied to production wells is significantly less than an amount of heat applied to heat sources that heat the formation.

Certain in situ conversion embodiments may include providing heat to a first portion of a hydrocarbon containing formation from one or more heat sources. Formation fluids may be produced from the first portion. A second portion of the formation may remain unpyrolyzed by maintaining temperature in the second portion below a pyrolysis temperature of hydrocarbons in the formation. In some embodiments, the second portion or significant sections of the second portion may remain unheated.

A second portion that remains unpyrolyzed may be adjacent to a first portion of the formation that is subjected to pyrolysis. The second portion may provide structural strength to the formation. The second portion may be between the first portion and the third portion. Formation fluids may be produced from the third portion of the formation. A processed formation may have a pattern that resembles a striped or checkerboard pattern with alternating pyrolyzed portions and unpyrolyzed portions. In some in situ conversion embodiments, columns of unpyrolyzed portions of formation may remain in a formation that has undergone in situ conversion.

Unpyrolyzed portions of formation among pyrolyzed portions of formation may provide structural strength to the formation. The structural strength may inhibit subsidence of the formation. Inhibiting subsidence may reduce or eliminate subsidence problems such as changing surface levels and/or decreasing permeability and flow of fluids in the formation due to compaction of the formation.

In some in situ conversion process embodiments, a portion of a hydrocarbon containing formation may be heated at a heating rate in a range from about 0.1 °C/day to about 50 °C/day. Alternatively, a portion of a hydrocarbon containing formation may be heated at a heating rate in a range of about 0.1 °C/day to about 10 °C/day. For example, a majority of hydrocarbons may be produced from a formation at a heating rate within a range of about 0.1 °C/day to about 10 °C/day. In addition, a hydrocarbon containing formation may be heated at a rate of less than about 0.7 °C/day through a significant portion of a pyrolysis temperature range. The pyrolysis temperature range may include a range of temperatures as described in above embodiments. For example, the heated portion may be heated at such a rate for a time greater than 50% of the time needed to span the temperature range, more than 75% of the time needed to span the temperature range, or more than 90% of the time needed to span the temperature range.

Subsurface pressure in a hydrocarbon containing formation may correspond to the fluid pressure generated within the formation. Heating hydrocarbons within a hydrocarbon containing formation may generate fluids by pyrolysis. The generated fluids may be vaporized within the formation. Vaporization and pyrolysis reactions may increase the pressure within the formation. Fluids that contribute to the increase in pressure may include, but are not limited to, fluids produced during pyrolysis and water vaporized during heating. As temperatures within a selected section of a heated portion of the formation increase, a pressure within the selected section may increase as a result of increased fluid generation and vaporization of water. Controlling a rate of fluid removal from the formation may allow for control of pressure in the formation.

In some embodiments, pressure within a selected section of a heated portion of a hydrocarbon containing formation may vary depending on factors such as depth, distance from a heat source, a richness of the hydrocarbons within the hydrocarbon containing formation, and/or a distance from a producer well. Pressure within a formation may be determined at a number of different locations (e.g., near or at production wells, near or at heat sources, or at monitor wells).

Heating of a hydrocarbon containing formation to a pyrolysis temperature range may occur before substantial permeability has been generated within the hydrocarbon containing formation. An initial lack of permeability may inhibit the transport of generated fluids from a pyrolysis zone within the formation to a production well. As heat is initially transferred from a heat source to a hydrocarbon containing formation, a fluid pressure within the hydrocarbon containing formation may increase proximate a heat source. Such an increase in fluid pressure may be caused by generation of fluids during pyrolysis of at least some hydrocarbons in the formation. The increased fluid pressure may be released, monitored, altered, and/or controlled through the heat source. For example, the heat source may include a valve that allows for removal of some fluid from the formation. In some heat source embodiments, the heat source may include an open wellbore configuration that inhibits pressure damage to the heat source.

In some in situ conversion process embodiments, pressure generated by expansion of pyrolysis fluids or other fluids generated in the formation may be allowed to increase although an open path to the production well or any other pressure sink may not yet exist in the formation. The fluid pressure may be allowed to increase towards a lithostatic pressure. Fractures in the hydrocarbon containing formation may form when the fluid approaches the lithostatic pressure. For example, fractures may form from a heat source to a production well. The generation of fractures within the heated portion may relieve some of the pressure within the portion.

In an in situ conversion process embodiment, pressure may be increased within a selected section of a portion of a hydrocarbon containing formation to a selected pressure during pyrolysis. A selected pressure may be within a range from about 2 bars absolute to about 72 bars absolute or, in some embodiments, 2 bars absolute to 36 bars absolute. Alternatively, a selected pressure may be within a range from about 2 bars absolute to about 18 bars absolute. In some in situ conversion process embodiments, a majority of hydrocarbon fluids may be produced from a formation having a pressure within a range from about 2 bars absolute to about 18 bars absolute. The pressure during pyrolysis may vary or be varied. The pressure may be varied to alter and/or control a composition of a formation fluid produced, to control a percentage of condensable fluid as compared to non-condensable fluid, and/or to control an API gravity of fluid being produced. For example, decreasing pressure may result in production of a larger condensable fluid component. The condensable fluid component may contain a larger percentage of olefins.

In some in situ conversion process embodiments, increased pressure due to fluid generation may be maintained within the heated portion of the formation. Maintaining increased pressure within a formation may inhibit formation subsidence during in situ conversion. Increased formation pressure may promote generation of high quality products during pyrolysis. Increased formation pressure may facilitate vapor phase production of fluids from the formation. Vapor phase production may allow for a reduction in size of collection conduits used to transport fluids produced from the formation. Increased formation pressure may reduce or eliminate the need to compress formation fluids at the surface to transport the fluids in collection conduits to treatment facilities.

Increased pressure in the formation may also be maintained to produce more and/or improved formation fluids. In certain in situ conversion process embodiments, significant amounts (e.g., a majority) of the hydrocarbon fluids produced from a formation may be non-condensable hydrocarbons. Pressure may be selectively increased and/or maintained within the formation to promote formation of smaller chain hydrocarbons in the formation. Producing small chain hydrocarbons in the formation may allow more non-condensable hydrocarbons to be produced from the formation. The condensable hydrocarbons produced from the formation at higher pressure may be of a higher quality (e.g., higher API gravity) than condensable hydrocarbons produced from the formation at a lower pressure.

A high pressure may be maintained within a heated portion of a hydrocarbon containing formation to inhibit production of formation fluids having carbon numbers greater than, for example, about 25. Some high carbon number compounds may be entrained in vapor in the formation and may be removed from the formation with the vapor. A high pressure in the formation may inhibit entrainment of high carbon number compounds and/or multi-ring hydrocarbon compounds in the vapor. Increasing pressure within the hydrocarbon containing formation may increase a boiling point of a fluid within the portion. High carbon number compounds and/or multi-ring hydrocarbon compounds may remain in a liquid phase in the formation for significant time periods. The significant time periods may provide sufficient time for the compounds to pyrolyze to form lower carbon number compounds.

Maintaining increased pressure within a heated portion of the formation may surprisingly allow for production of large quantities of hydrocarbons of increased quality. Higher pressures may inhibit vaporization of higher molecular weight hydrocarbons. Inhibiting vaporization of higher molecular weight hydrocarbons may result in higher molecular weight hydrocarbons remaining in the formation. Higher molecular weight hydrocarbons may react with lower molecular weight hydrocarbons in the formation to vaporize the lower molecular weight hydrocarbons. Vaporized hydrocarbons may be more readily transported through the formation.

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

Operating an in situ conversion process at increased pressure may allow for vapor phase production of formation fluid from the formation. Vapor phase production may permit increased recovery of lighter (and relatively high quality) pyrolyzation fluids. Vapor phase production may result in less formation fluid being left in the formation after the fluid is produced by pyrolysis. Vapor phase production may allow for fewer production wells in the formation than are present using liquid phase or liquid/vapor phase production. Fewer production wells may significantly reduce equipment costs associated with an in situ conversion process.

In an embodiment, a portion of a hydrocarbon containing formation may be heated to increase a partial pressure of H_2. In some embodiments, an increased H_2 partial pressure may include H_2 partial pressures in a range from about 0.5 bars absolute to about 7 bars absolute. Alternatively, an increased H_2 partial pressure range may include H_2 partial pressures in a range from about 5 bars absolute to about 7 bars absolute. For example, a majority of hydrocarbon fluids may be produced wherein a H_2 partial pressure is within a range of about 5 bars absolute to about 7 bars absolute. A range of H_2 partial pressures within the pyrolysis H_2 partial pressure range may vary depending on, for example, temperature and pressure of the heated portion of the formation.

Maintaining a H_2 partial pressure within the formation of greater than atmospheric pressure may increase an API value of produced condensable hydrocarbon fluids. Maintaining an increased H_2 partial pressure may increase an API value of produced condensable hydrocarbon fluids to greater than about 25° or, in some instances, greater than about 30°. Maintaining an increased H_2 partial pressure within a heated portion of a hydrocarbon containing formation may increase a concentration of H_2 within the heated portion. The H_2 may be available to react with pyrolyzed components of the hydrocarbons. Reaction of H_2 with the pyrolyzed components of hydrocarbons may reduce polymerization of olefins into tars and other cross-linked, difficult to upgrade, products. Therefore, production of hydrocarbon fluids having low API gravity values may be inhibited.

Controlling pressure and temperature within a hydrocarbon containing formation may allow properties of the produced formation fluids to be controlled. For example, composition and quality of formation fluids produced from the formation may be altered by altering an average pressure and/or an average temperature in a selected section of a heated portion of the formation. The quality of the produced fluids may be evaluated based on characteristics of the fluid such as, but not limited to, API gravity, percent olefins in the produced formation fluids, ethene to ethane ratio, atomic hydrogen to carbon ratio, percent of hydrocarbons within produced formation fluids having carbon numbers greater than 25, total equivalent production (gas and liquid), total liquids production, and/or liquid yield as a percent of Fischer Assay.

In an in situ conversion process embodiment, heating a portion of a hydrocarbon containing formation in situ to a temperature less than an upper pyrolysis temperature may increase permeability of the heated portion. Permeability may increase due to formation of thermal fractures within the heated portion. Thermal fractures may be generated by thermal expansion of the formation and/or by localized increases in pressure due to vaporization of liquids (e.g., water and/or hydrocarbons) in the formation. As a temperature of the heated portion increases, water in the formation may be vaporized. The vaporized water may escape and/or be removed from the formation. Removal of water may also increase the permeability of the heated portion. In addition, permeability of the heated portion may also increase as a result of mass loss from the formation due to generation of pyrolysis fluids in the formation. Pyrolysis fluid may be removed from the formation through production wells.

Heating the formation from heat sources placed in the formation may allow a permeability of the heated portion of a hydrocarbon containing formation to be substantially uniform. A substantially uniform permeability may inhibit channeling of formation fluids in the formation and allow production from substantially all portions of the heated formation. An assessed (e.g., calculated or estimated) permeability of any selected portion in the formation having a substantially uniform permeability may not vary by more than a factor of 10 from an assessed average permeability of the selected portion.

Permeability of a selected section within the heated portion of the hydrocarbon containing formation may rapidly increase when the selected section is heated by conduction. In some embodiments, pyrolyzing at least a portion of a hydrocarbon containing formation may increase a permeability within a selected section of the portion to greater than about 10 millidarcy, 100 millidarcy, 1 darcy, 10 darcy, 20 darcy, or 50 darcy. A permeability of a selected section of the portion may increase by a factor of more than about 100, 1,000, 10,000, 100,000 or more.

In some in situ conversion process embodiments, superposition (e.g., overlapping influence) of heat from one or more heat sources may result in substantially uniform heating of a portion of a hydrocarbon containing formation. Since formations during heating will typically have a temperature gradient that is highest near heat sources and reduces with increasing distance from the heat sources, "substantially uniform" heating means heating such that temperature in a majority of the section does not vary by more than 100 °C from an assessed average temperature in the majority of the selected section (volume) being treated.

In an embodiment, production of hydrocarbons from a formation is inhibited until at least some hydrocarbons within the formation have been pyrolyzed. A mixture may be produced from the formation at a time when the mixture includes a selected quality in the mixture (e.g., API gravity, hydrogen concentration, aromatic content, etc.). In some embodiments, the selected quality includes an API gravity of at least about 20°, 30°, or 40°. Inhibiting production until at least some hydrocarbons are pyrolyzed may increase conversion of heavy hydrocarbons to light hydrocarbons. Inhibiting initial production may minimize the production of heavy hydrocarbons from the formation. Production of substantial amounts of heavy hydrocarbons may require expensive equipment and/or reduce the life of production equipment.

When production of hydrocarbons from the formation is inhibited, the pressure in the formation tends to increase with temperature in the formation because of thermal expansion and/or phase change of heavy hydrocarbons and other fluids (e.g., water) in the formation. Pressure within the formation may have to be maintained below a selected pressure to inhibit unwanted production, fracturing of the overburden or underburden, and/or coking of hydrocarbons in the formation. The selected pressure may be a lithostatic or hydrostatic pressure of the formation. For example, the selected pressure may be about 150 bars absolute or, in some embodiments, the selected pressure may be about 35 bars absolute. The pressure in the formation may be controlled by controlling production rate from production wells in the formation. In other embodiments, the pressure in the formation is controlled by releasing pressure through one or more pressure relief wells in the formation. Pressure relief wells may be heat sources or separate wells inserted into the formation. Formation fluid removed from the formation through the relief wells may be sent to a treatment facility. Producing at least some hydrocarbons from the formation may inhibit the pressure in the formation from rising above the selected pressure.

In some hydrocarbon containing formations (e.g., in Green River oil shale), there may be one or more hydrocarbon layers characterized by a significantly higher richness than other layers in the formation. These rich layers tend to be relatively thin (typically about 0.2 m to about 0.5 m thick) and may be spaced throughout the formation. The rich layers generally have a richness of about 0.150 L/kg or greater. Some rich layers may have a richness greater than about 0.170 L/kg, greater than about 0.190 L/kg, or greater then about 0.210 L/kg. Other layers (i.e., relatively lean layers) of the formation may have a richness of about 0.100 L/kg or less and are generally thicker than rich layers. The richness and locations of layers may be determined, for example, by coring and subsequent Fischer assay of the core, density or neutron logging, or other logging methods.

FIG. 3 depicts an embodiment of a heater in an open wellbore of a hydrocarbon containing formation with a rich layer. Opening 120 may be located in hydrocarbon layer 122. Hydrocarbon layer 122 may include one or more rich layers 124. Relatively lean layers 126 in hydrocarbon layer 122 may have a lower richness than rich layers 124. Heater 128 may be placed in opening 120. In certain embodiments, opening 120 may be an open or uncased wellbore.

Rich layers 124 may have a lower initial thermal conductivity than other layers of the formation. Typically, rich layers 124 have a thermal conductivity 1.5 times to 3 times lower than the thermal conductivity of lean layers 126. For example, a rich layer may have a thermal conductivity of about 1.5×10^{-3} cal/cm·sec·°C while a lean layer of the formation may have a thermal conductivity of about 3.5×10^{-3} cal/cm·sec·°C. In addition, rich layers 124 may have a higher thermal expansion coefficient than lean layers of the formation. For example, a rich layer of 57 gal/ton (0.24 L/kg) oil shale may have a thermal expansion coefficient of about 2.2×10^{-2} %/°C while a lean layer of the formation of about 13 gal/ton (0.05 L/kg) oil shale may have a thermal expansion coefficient of about 0.63×10^{-2} %/°C.

Because of the lower thermal conductivity in rich layers 124, rich layers may cause "hot spots" on heaters during heating of the formation around opening 120. The "hot spots" may be generated because heat provided from the heater in opening 120 does not transfer into hydrocarbon layer 122 as readily as through rich layers 124 due to the lower thermal conductivity of the rich layers. Thus, the heat tends to stay at or near the wall of opening 120 during early stages of heating.

Material that expands from rich layers 124 into the wellbore may be significantly less stressed than material in the formation. Thermal expansion and pyrolysis may cause additional fracturing and exfoliation of hydrocarbon material that expands into the wellbore. Thus, after pyrolysis of expanded material in the wellbore, the expanded material may have an even lower thermal conductivity than pyrolyzed material in the formation. Under low stress, pyrolysis may cause additional fracturing and/or exfoliation of material, thus causing a decrease in thermal conductivity. The lower thermal conductivity may be caused by the lower stress placed on pyrolyzed materials that have expanded into the wellbore (i.e., pyrolyzed material that has expanded into the wellbore is no longer as stressed as the pyrolyzed material would be if the pyrolyzed material were still in the formation). This release of stress tends to lower the thermal conductivity of the expanded, pyrolyzed material.

After the formation of "hot spots" at rich layers 124, hydrocarbons in the rich layers will tend to expand at a much faster rate than other layers of the formation due to increased heat at the wall of the wellbore and the higher thermal expansion coefficient of the rich layers. Expansion of the formation into the wellbore may reduce radiant heat transfer to the formation. The radiant heat transfer may be reduced for a number of reasons, including, but not limited to, material contacting the heater, thus stopping radiant heat transfer; and reduction of wellbore radius which limits the surface area that radiant heat is able to transfer to. Reduction of radiant heat transfer may result in higher heater temperature adjacent to areas with reduced radiant heat transfer acceptance capability.

Rich layers 124 may expand at a much faster rate than lean layers because of the significantly lower thermal conductivity of rich layers and/or the higher thermal expansion coefficient of the rich layers. The expansion may apply significant pressure to a heater when the wellbore closes off against the heater. The wellbore closing off, or substantially closing off against the heater may also inhibit flow of fluids between layers of the formation. In some embodiments, fluids may become trapped in the wellbore because of the closing off or substantial closing off of the wellbore against the heater.

FIG. 4 depicts an embodiment of heater 128 in opening 120 with expanded rich layer 124. In some embodiments, opening 120 may be closed off by the expansion of rich layer 124, as shown in FIG. 4, (i.e., an annular space between the heater and wall of the opening may be closed off by expanded material). Closing off of the annulus of the opening may trap fluids between expanded rich layers in the opening. The trapping of fluids can increase pressures in the opening beyond desirable limits. In some circumstances, the increased pressure could cause fracturing of the formation or in the heater well that would allow fluid to unexpectedly be in communication with an opening from the formation. In some circumstances, the increased pressure may exceed a deformation pressure of the heater. Deformation of the heater may also be caused by the expansion of material from the rich layers against the heater. Deformation may also be caused by pressure buildup from gases trapped at an interface of expanded material and a heater. The trapped gases may increase in pressure due to heating, cracking, and/or pyrolysis. Deformation of the heater may cause the heater to shut down or fail. Thus, the expansion of material in rich layers may need to be reduced and/or deformation of a heater in the opening may need to be inhibited so that the heater operates properly.

A significant amount of the expansion of rich layers tends to occur during early stages of heating (e.g., often within the first 15 days or 30 days of heating at a heat injection rate of about 820 watts/meter). Typically, a majority of the expansion occurs below about 200 °C in the near wellbore region. For example, a 0.189 L/kg hydrocarbon containing layer will expand about 5 cm up to about 200 °C depending on factors such as, but not limited to, heating rate, formation stresses, and wellbore diameter. Methods for compensating for the expansion of rich layers of a formation may be focused on in the early stages of an in situ process. The amount of expansion during or after heating of the formation may be estimated or determined before heating of the formation begins. Thus, allowances may be made to compensate for the thermal expansion of rich layers and/or lean layers in the formation. The amount of expansion caused by heating of the formation may be estimated based on factors such as, but not limited to, measured or estimated richness of layers in the formation, thermal conductivity of layers in the formation, thermal expansion coefficients (e.g., linear thermal expansion coefficient) of layers in the formation, formation stresses, and expected temperature of layers in the formation.

FIG. 5 depicts simulations (using a reservoir simulator (STARS) and a mechanical simulator (ABAQUS)) of wellbore radius change versus time for heating of a 20 gal/ton oil shale (0.084 L/kg oil shale) in an open wellbore for a heat output of 820 watts/meter (plot 130) and a heat output of 1150 watts/meter (plot

132). As shown in FIG. 5, the maximum expansion of a 20 gal/ton oil shale increases from about 0.38 cm to about 0.48 cm for increased heat output from 820 watts/meter to 1150 watts/meter. FIG. 6 depicts calculations of wellbore radius change versus time for heating of a 50 gal/ton oil shale (0.21 L/kg oil shale) in an open wellbore for a heat output of 820 watts/meter (plot 134) and a heat output of 1150 watts/meter (plot 136). As shown in FIG. 6, the maximum expansion of a 50 gal/ton oil shale increases from about 8.2 cm to about 10 cm for increased heat output from 820 watts/meter to 1150 watts/meter. Thus, the expansion of the formation depends on the richness of the formation, or layers of the formation, and the heat output to the formation.

In one embodiment, opening 120 may have a larger diameter to inhibit closing off of the annulus after expansion of rich layers 124. A typical opening may have a diameter of about 16.5 cm. In certain embodiments, heater 128 may have a diameter of about 7.3 cm. Thus, about 4.6 cm of expansion of rich layers 124 will close off the annulus. If the diameter of opening 120 is increased to about 30 cm, then about 11.3 cm of expansion would be needed to close off the annulus. The diameter of opening 120 may be chosen to allow for a certain amount of expansion of rich layers 124. In some embodiments, a diameter of opening 120 may be greater than about 20 cm, greater than about 30 cm, or greater than about 40 cm. Larger openings or wellbores also may increase the amount of heat transferred from the heater to the formation by radiation. Radiative heat transfer may be more efficient for transfer of heat within the opening. The amount of expansion expected from rich layers 124 may be estimated based on richness of the layers. The diameter of opening 120 may be selected to allow for the maximum expansion expected from a rich layer so that a minimum space between a heater and the formation is maintained after expansion. Maintaining a minimum space between a heater and the formation may inhibit deformation of the heater caused by the expansion of material into the opening. In an embodiment, a desired minimum space between a heater and the formation after expansion may be at least about 0.25 cm, 0.5 cm, or 1 cm. In some embodiments, a minimum space may be at least about 1.25 cm or at least about 1.5 cm, and may range up to about 3 cm, about 4 cm, or about 5 cm.

In some embodiments, opening 120 may be expanded proximate rich layers 124, as depicted in FIG. 7, to maintain a minimum space between a heater and the formation after expansion of the rich layers. Opening 120 may be expanded proximate rich layers by underreaming of the opening. For example, an eccentric drill bit, an expanding drill bit, or high-pressure water jet with abrasive particles may be used to expand an opening proximate rich layers. Opening 120 may be expanded beyond the edges of rich layers 124 so that some material from lean layers 126 is also removed. Expanding opening 120 with overlap into lean layers 126 may further allow for expansion and/or any possible indeterminations in the depth or size of a rich layer.

In another embodiment, heater 128 may include sections 138 that provide less heat output proximate rich layers 124 than sections 140 that provide heat to lean layers 126, as shown in FIG. 7. Section 138 may provide less heat output to rich layers 124 so that the rich layers are heated at a lower rate than lean layers 126. Providing less heat to rich layers 124 will reduce the wellbore temperature proximate the rich layers, thus reducing the total expansion of the rich layers. In an embodiment, heat output of sections 138 may be about one half of heat output from sections 140. In some embodiments, heat output of sections 138 may be less than about three quarters, less than about one half, or less than about one third of heat output of sections 140. Generally, a heating rate of rich layers 124 may be lowered to a heat output that limits the expansion of rich layers 124 so that a minimum space between heater 128 and rich layers 124 in opening 120 is maintained after expansion. Heat output from heater 128 may be controlled to provide lower heat output proximate rich layers. In some embodiments, heater 128 may be constructed or modified to provide lower heat output proximate rich layers. Examples of such heaters include heaters with temperature limiting characteristics, such as Curie temperature heaters, tailored heaters with less resistive sections proximate rich layers, etc.

In some embodiments, opening 120 may be reopened after expansion of rich layers 124 (e.g., after about 15 to 30 days of heating at 820 Watts/m). Material from rich layers 124 may be allowed to expand into opening 120 during heating of the formation with heater 128, as shown in FIG. 4. After expansion of material into opening 120, an annulus of the opening may be reopened, as shown in FIG. 3. Reopening the annulus of opening 120 may include over washing the opening after expansion with a drill bit or any other method used to remove material that has expanded into the opening.

In certain embodiments, pressure tubes (e.g., capillary pressure tubes) may be coupled to the heater at varying depths to assess if and/or when material from the formation has expanded and sealed the annulus. In some embodiments, comparisons of the pressures at varying depths may be used to determine when an opening should be reopened. In certain embodiments, an optical sensor (e.g., a fiber optic cable) may be employed that detects stresses from formation material that has expanded against a heater or conduit. Such optical sensors may utilize Brillioun scattering to simultaneously measure a stress profile and a temperature profile. These measurements may be used to control the heater temperature (e.g., reduce the heater temperature at or near locations of high stress) to inhibit deformation of the heater or conduit due to stresses from expanded formation material.

In certain embodiments, rich layers 124 and/or lean layers 126 may be perforated. Perforating rich layers 124 and/or lean layers 126 may allow expansion of material within these layers and inhibit or reduce expansion into opening 120. Small holes may be formed into rich layers 124 and/or lean layers 126 using perforation equipment (e.g., bullet or jet perforation). Such holes may be formed in both cased wellbores and open wellbores. These small holes may have diameters less than about 1 cm, less than about 2 cm, or less than about 3 cm. In some embodiments, larger holes may also be formed. These holes may be designed to provide, or allow, space for the formation to expand. The holes may also weaken the rock matrix of a formation so that if the formation does expand, the formation will exert less force. In some embodiments, the formation may be fractured instead of using a perforation gun.

In certain embodiments, a liner or casing may be placed in an open wellbore to inhibit collapse of the wellbore during heating of the formation. FIG. 8 depicts an embodiment of a heater in an open wellbore with a liner placed in the opening. Liner 142 may be placed in opening 120 in hydrocarbon layer 122. Liner 142 may include first sections 144 and second sections 146. First sections 144 may be located proximate lean layers 126. Second sections 146 may be located proximate rich layers 124. Second sections 146 may be thicker than first sections 144. Additionally, second sections 146 may be made of a stronger material than first sections 144.

In one embodiment, first sections 144 are carbon steel with a thickness of about 2 cm and second sections 146 are Haynes® HR-120® (available from Haynes International Inc. (Kokomo, IN)) with a thickness of about 4 cm. The thicknesses of first sections 144 and second sections 146 may be varied between about 0.5 cm and about 10 cm. The thicknesses of first sections 144 and second sections 146 may be selected based upon factors such as, but not limited to, a diameter of opening 120, a desired thermal transfer rate from heater 128 to hydrocarbon layer 122, and/or a mechanical strength required to inhibit collapse of liner 142. Other materials may also be used for first sections 144 and second sections 146. For example, first sections 144 may include, but may not be limited to, carbon steel, stainless steel, aluminum, etc. Second sections 146 may include, but may not be limited to, 304H stainless steel, 316H stainless steel, 347H stainless steel, Incoloy® alloy 800H or Incoloy® alloy 800HT (both available from Special Metals Co. (New Hartford, NY)), Inconel® 625, etc.

FIG. 9 depicts an embodiment of a heater in an open wellbore with a liner placed in the opening and the formation expanded against the liner. Second sections 146 may inhibit material from rich layers 124 from closing off an annulus of opening 120 (between liner 142 and heater 128) during heating of the formation. Second sections 146 may have a sufficient strength to inhibit or slow down the expansion of material from rich layers 124. One or more openings 148 may be placed in liner 142 to allow fluids to flow from the annulus between liner 142 and the walls of opening 120 into the annulus between the liner and heater 128. Thus, liner 142 may maintain an open annulus between the liner and heater 128 during expansion of rich layers 124 so that fluids can continue to flow through the annulus. Maintaining a fluid path in opening 120 may inhibit a buildup of pressure in the opening. Second sections 146 may also inhibit closing off of the annulus between liner 142 and heater 128 so that hot spot formation is inhibited, thus allowing the heater to operate properly.

In some embodiments, conduit 150 may be placed inside opening 120 as shown in FIGS. 8 and 9. Conduit 150 may include one or more openings for providing a fluid to opening 120. In an embodiment, steam may be provided to opening 120. The steam may inhibit coking in openings 148 along a length of liner 142, such that openings are not clogged and fluid flow through the openings is maintained. Air may also be supplied through conduit to periodically decoke a plugged opening. In certain embodiments, conduit 150 may be placed inside liner 142. In other embodiments, conduit 150 may be placed outside liner 142. Conduit 150 may also be permanently placed in opening 120 or may be temporarily placed in the opening (e.g., the conduit may be spooled and unspooled into an opening). Conduit 150 may be spooled and unspooled into an opening so that the conduit can be used in more than one opening in a formation.

FIG. 10 depicts maximum radial stress 152, maximum circumferential stress 154, and hole size 156 after 300 days versus richness for calculations of heating in an open wellbore. The calculations were done with a reservoir simulator (STARS) and a mechanical simulator (ABAQUS) for a 16.5 cm wellbore with a 14.0 cm liner placed in the wellbore and a heat output from the heater of 820 watts/meter. As shown in FIG. 10, the maximum radial stress and maximum circumferential stress decrease with richness. Layers with a richness above about 22.5 gal/ton (0.95 L/kg) may expand to contact the liner. As the richness increases above about 32 gal/ton (0.13 L/kg), the maximum stresses begin to somewhat level out at a value of about 270 bars absolute or below. The liner may have sufficient strength to inhibit deformation at the stresses above richnesses of about

32 gal/ton. Between about 22.5 gal/ton richness and about 32 gal/ton richness, the stresses may be significant enough to deform the liner. Thus, the diameter of the wellbore, the diameter of the liner, the wall thickness and strength of the liner, the heat output, etc. may have to be adjusted so that deformation of the liner is inhibited and an open annulus is maintained in the wellbore for all richnesses of a formation.

During early periods of heating a hydrocarbon containing formation, the formation may be susceptible to geomechanical motion. Geomechanical motion in the formation may cause deformation of existing wellbores in a formation. If significant deformation of wellbores occurs in a formation, equipment (e.g., heaters, conduits, etc.) in the wellbores may be deformed and/or damaged.

Geomechanical motion is typically caused by heat provided from one or more heaters placed in a volume in the formation that results in thermal expansion of the volume. The thermal expansion of a volume may be defined by the equation:

(1) $\Delta r = r \times \Delta T \times \alpha$;

where r is the radius of the volume (i.e., r is the length of the longest straight line in a footprint of the volume that has continuous heating, as shown in FIGS. 11 and 12), ΔT is the change in temperature, and α is the linear thermal expansion coefficient.

The amount of geomechanical motion generally increases as more heat is input into the formation. Geomechanical motion in the formation and wellbore deformation tend to increase as larger volumes of the formation are heated at a particular time. Therefore, if the volume heated at a particular time is maintained in selected size limits, the amount of geomechanical motion and wellbore deformation may be maintained below acceptable levels. Also, geomechanical motion in a first treatment area may be limited by heating a second treatment area and a third treatment area on opposite sides of the first treatment area. Geomechanical motion caused by heating the second treatment area may be offset by geomechanical motion caused by heating the third treatment area.

FIG. 11 depicts an embodiment of an aerial view of a pattern of heaters for heating a hydrocarbon containing formation. Heat sources 158 may be placed in formation 160. Heat sources 158 may be placed in a triangular pattern, as depicted in FIG. 11, or any other pattern as desired. Formation 160 may include one or more volumes 162, 164 to be heated. Volumes 162, 164 may be alternating volumes of formation 160 as depicted in FIG. 11. In some embodiments, heat sources 158 in volumes 162, 164 may be turned on, or begin heating, substantially simultaneously (i.e., heat sources 158 may be turned on within days or, in some cases, within 1 or 2 months of each other). Turning on all heat sources 158 in volumes 162, 164 may, however, cause significant amounts of geomechanical motion in formation 160. This geomechanical motion may deform the wellbores of one or more heat sources 158 and/or other wellbores in the formation. The outermost wellbores in formation 160 may be most susceptible to deformation. These wellbores may be more susceptible to deformation because geomechanical motion tends to be a cumulative effect, increasing from the center of a heated volume towards the perimeter of the heated volume.

FIG. 12 depicts an embodiment of an aerial view of another pattern of heaters for heating a hydrocarbon containing formation. Volumes 162, 164 may be concentric rings of volumes, as shown in FIG.

12. Heat sources 158 may be placed in a desired pattern or patterns in volumes 162, 164. In a concentric ring pattern of volumes 162, 164, the geomechanical motion may be reduced in the outer rings of volumes because of the increased circumference of the volumes as the rings move outward.

In other embodiments, volumes 162, 164 may have other footprint shapes and/or be placed in other shaped patterns. For example, volumes 162, 164 may have linear, curved, or irregularly shaped strip footprints. In some embodiments, volumes 164 may separate volumes 162 and thus be used to inhibit geomechanical motion in volumes 162 (i.e., volumes 164 may function as a barrier (e.g., a wall) to reduce the effect of geomechanical motion of one volume 162 on another volume 162).

In certain embodiments, heat sources 158 in volumes 162, 164, as shown in FIGS. 11 and 12, may be turned on at different times to avoid heating large volumes of the formation at one time and/or to reduce the effects of geomechanical motion. In one embodiment, heat sources 158 in volumes 162 may be turned on, or begin heating, at substantially the same time (i.e., within 1 or 2 months of each other). Heat sources 158 in volumes 164 may be turned off while volumes 162 are being heated. Heat sources 158 in volumes 164 may be turned on, or begin heating, a selected time after heat sources 158 in volumes 162 are turned on or begin heating. Providing heat to only volumes 162 for a selected period of time may reduce the effects of geomechanical motion in the formation during a selected period of time. During the selected period of time, some geomechanical motion may take place in volumes 162. The size, as well as shape and/or location, of volumes 162 may be selected to maintain the geomechanical expansion of the formation in these volumes below a maximum value. The maximum value of geomechanical expansion of the formation may be a value selected to inhibit deformation of one or more wellbores beyond a critical value of deformation (i.e., a point at which the wellbores are damaged or equipment in the wellbores is no longer useable).

The size, shape, and/or location of volumes 162 may be determined by simulation, calculation, or any suitable method for estimating the extent of geomechanical motion during heating of the formation. In one embodiment, simulations may be used to determine the amount of geomechanical motion that may take place in heating a volume of a formation to a predetermined temperature. The size of the volume of the formation that is heated to the predetermined temperature may be varied in the simulation until a size of the volume is found that maintains any deformation of a wellbore below the critical value.

Sizes of volumes 162, 164 may be represented by a footprint area on the surface of a volume and the depth of the portion of the formation contained in the volume. The sizes of volumes 162, 164 may be varied by varying footprint areas of the volumes. In an embodiment, the footprints of volumes 162, 164 may be less than about 10,000 square meters, less than about 6000 square meters, less than about 4000 square meters, or less than about 3000 square meters.

Expansion in a formation may be zone, or layer, specific. In some formations, layers or zones of the formation may have different thermal conductivities and/or different thermal expansion coefficients. For example, a hydrocarbon containing formation may have certain thin layers (e.g., layers having a richness above about 0.15 L/kg) that have lower thermal conductivities and higher thermal expansion coefficients than adjacent layers of the formation. The thin layers with low thermal conductivities and high thermal conductivities may lie within different horizontal planes of the formation. The differences in the expansion of thin layers may have to be accounted for in determining the sizes of volumes of the formation that are to be heated. Generally, the largest expansion may be from zones or layers with low thermal conductivities and/or high thermal expansion coefficients. In some embodiments, the size, shape, and/or location of volumes 162, 164 may be determined to accommodate expansion characteristics of low thermal conductivity and/or high thermal expansion layers.

In some embodiments, the size, shape, and/or location of volumes 164 may be selected to inhibit cumulative geomechanical motion from occurring in the formation. In certain embodiments, volumes 164 may have a volume sufficient to inhibit cumulative geomechanical motion from affecting spaced apart volumes 162. In one embodiment, volumes 164 may have a footprint area substantially similar to the footprint area of volumes 162. Having volumes 162, 164 of substantially similar size may establish a uniform heating profile in the formation.

In certain embodiments, heat sources 158 in volumes 164 may be turned on at a selected time after heat sources 158 in volumes 162 have been turned on. Heat sources 158 in volumes 164 may be turned on, or begin heating, within about 6 months (or within about 1 year or about 2 years) from the time heat sources 158 in volumes 162 begin heating. Heat sources 158 in volumes 164 may be turned on after a selected amount of expansion has occurred in volumes 162. In one embodiment, heat sources 158 in volumes 164 are turned on after volumes 162 have geomechanically expanded to or nearly to their maximum possible expansion. For example, heat sources 158 in volumes 164 may be turned on after volumes 162 have geomechanically expanded to greater than about 70%, greater than about 80%, or greater than about 90% of their maximum estimated expansion. The estimated possible expansion of a volume may be determined by a simulation, or other suitable method, as the expansion that will occur in a volume when the volume is heated to a selected average temperature. Simulations may also take into effect strength characteristics of a rock matrix. Strong expansion in a formation occurs up to typically about 200 °C. Expansion in the formation is generally much slower from about 200 °C to about 350 °C. At temperatures above retorting temperatures, there may be little or no expansion in the formation. In some formations, there may be compaction of the formation above retorting temperatures. The average temperature used to determine estimated expansion may be, for example, a maximum temperature that the volume of the formation is heated to during in situ treatment of the formation (e.g., about 325 °C, about 350 °C, etc.). Heating volumes 164 after significant expansion of volumes 162 occurs may reduce, inhibit, and/or accommodate the effects of cumulative geomechanical motion in the formation.

In some embodiments, heat sources 158 in volumes 164 may be turned on after heat sources 158 in volumes 162 at a time selected to maintain a relatively constant production rate from the formation. Maintaining a relatively constant production rate from the formation may reduce costs associated with equipment used for producing fluids and/or treating fluids produced from the formation (e.g., purchasing equipment, operating equipment, purchasing raw materials, etc.). In certain embodiments, heat sources 158 in volumes 164 may be turned on after heat sources 158 in volumes 162 at a time selected to enhance a production rate from the formation. Simulations, or other suitable methods, may be used to determine the relative time at which heat sources 158 in volumes 162 and heat sources 158 in volumes 164 are turned on to maintain a production rate, or enhance a production rate, from the formation.

Some embodiments of heaters may include switches (e.g., fuses and/or thermostats) that turn off power to a heater or portions of a heater when a certain condition is reached in the heater. In certain embodiments, a "temperature limited heater" may be used to provide heat to a hydrocarbon containing formation. A temperature limited heater generally refers to a heater that regulates heat output (e.g., reduces heat output) above a specified temperature without the use of external controls such as temperature controllers, power regulators, etc. Temperature limited heaters may be AC (alternating current) electrical resistance heaters.

Temperature limited heaters may be more reliable than other heaters. Temperature limited heaters may be less apt to break down or fail due to hot spots in the formation. In some embodiments, temperature limited heaters may allow for substantially uniform heating of a formation. In some embodiments, temperature limited heaters may be able to heat a formation more efficiently by operating at a higher average temperature along the entire length of the heater. The temperature limited heater may be operated at the higher average temperature along the entire length of the heater because power to the heater does not have to be reduced to the entire heater (e.g., along the entire length of the heater), as is the case with typical heaters, if a temperature along any point of the heater exceeds, or is about to exceed, a maximum operating temperature of the heater. Heat output from portions of a temperature limited heater approaching a Curie temperature of the heater may automatically reduce. The heat output may automatically reduce due to changes in electrical properties (e.g., electrical resistance) of portions of the temperature limited heater. Thus, more power may be supplied to the temperature limited heater during a greater portion of a heating process.

In the context of reduced heat output heating systems, apparatus, and methods, the term "automatically" means such systems, apparatus, and methods function in a certain way without the use of external control (e.g., external controllers such as a controller with a temperature sensor and a feedback loop). For example, a system including temperature limited heaters may initially provide a first heat output, and then provide a reduced heat output, near, at, or above a Curie temperature of an electrically resistive portion of the heater when the temperature limited heater is energized by an alternating current.

Temperature limited heaters may be in configurations and/or may include materials that provide automatic temperature limiting properties for the heater at certain temperatures. For example, ferromagnetic materials may be used in temperature limited heater embodiments. Ferromagnetic material may self-limit temperature at or near a Curie temperature of the material to provide a reduced heat output at or near the Curie temperature when an alternating current is applied to the material. In certain embodiments, ferromagnetic materials may be coupled with other materials (e.g., non-ferromagnetic materials and/or highly conductive materials) to provide various electrical and/or mechanical properties. Some parts of a temperature limited heater may have a lower resistance (caused by different geometries and/or by using different ferromagnetic and/or non-ferromagnetic materials) than other parts of the temperature limited heater. Having parts of a temperature limited heater with various materials and/or dimensions may allow for tailoring a desired heat output from each part of the heater. Using ferromagnetic materials in temperature limited heaters may be less expensive and more reliable than using switches in temperature limited heaters.

Curie temperature is the temperature above which a magnetic material (e.g., a ferromagnetic material) loses its magnetic properties. In addition to losing magnetic properties above the Curie temperature, a ferromagnetic material may begin to lose its magnetic properties when an increasing electrical current is passed through the ferromagnetic material.

A heater may include a conductor that operates as a skin effect heater when alternating current is applied to the conductor. The skin effect limits the depth of current penetration into the interior of the conductor. For ferromagnetic materials, the skin effect is dominated by the magnetic permeability of the conductor. The magnetic permeability of ferromagnetic materials is typically greater than 10 and may be greater than 50, 100, 500 or even 1000. As the temperature of the ferromagnetic material is raised above the Curie temperature and/or as an applied electrical current is increased, the magnetic permeability of the ferromagnetic material decreases substantially and the skin depth expands rapidly (e.g., as the inverse square root of the magnetic permeability). The reduction in magnetic permeability results in a decrease in the AC resistance of the conductor near, at, or above the Curie temperature and/or as an applied electrical current is increased. When the heater is powered by a substantially constant current source, portions of the heater that approach, reach, or are above the Curie temperature may have reduced heat dissipation. Sections of the heater that are not at or near the Curie temperature may be dominated by skin effect heating that allows the heater to have high heat dissipation.

In some embodiments, a temperature limited heater (e.g., a Curie temperature heater) may be formed of a paramagnetic material. A paramagnetic material typically has a relative magnetic permeability that is greater than 1 and less than 10. Temperature limiting characteristics of a temperature limited heater formed of paramagnetic heater may be significantly less pronounced than temperature limiting characteristics of a temperature limited heater formed of ferromagnetic material.

An advantage of using a temperature limited heater to heat a hydrocarbon containing formation may be that the conductor can be chosen to have a Curie temperature in a desired range of temperature operation. The desired operating range may allow substantial heat injection into the formation while maintaining the temperature of the heater, and other equipment, below design temperatures (i.e., below temperatures that will adversely affect properties such as corrosion, creep, and/or deformation). The temperature limiting properties of the heater may inhibit overheating or burnout of the heater adjacent to low thermal conductivity "hot spots" in the formation. In some embodiments, a temperature limited heater may be able to withstand temperatures above about 250 °C, about 500 °C, about 700 °C, about 800 °C, about 900 °C, or higher depending on the materials used in the heater.

A temperature limited heater may allow for more heat injection into a formation than constant wattage heaters because the energy input into the temperature limited heater does not have to be limited to accommodate low thermal conductivity regions adjacent to the heater. For example, in Green River oil shale there is a difference of at least 50% in the thermal conductivity of the lowest richness hydrocarbon containing layers (less than about 0.04 L/kg) and the highest richness hydrocarbon containing layers (greater than about 0.20 L/kg). When heating such a formation, substantially more heat may be transferred to the formation with a temperature limited heater than with a heater that is limited by the temperature at low thermal conductivity layers, which may be only about 0.3 m thick. Because heaters for heating hydrocarbon formations typically have long lengths (e.g., greater than 10 m, 100 m, or 300 m), the majority of the length of the heater may be operating below the Curie temperature while only a few portions are at or near the Curie temperature of the heater.

The diameter of a temperature limited heater may be small enough to inhibit deformation of the heater by a collapsing formation. In certain embodiments, the outside diameter of a temperature limited heater may be less than about 5 cm. In some embodiments, the outside diameter of a temperature limited heater may be less than about 4 cm, less than about 3 cm, or between about 2 cm and about 5 cm.

In heater embodiments described herein (including, but not limited to, temperature limited heaters, insulated conductor heaters, conductor-in-conduit heaters, and elongated member heaters), a largest transverse cross-sectional dimension of a heater may be selected to provide a desired ratio of the largest transverse cross-sectional dimension to wellbore diameter (e.g., initial wellbore diameter). The largest transverse cross-sectional dimension is the largest dimension of the heater on the same axis as the wellbore diameter (e.g., the diameter of a cylindrical heater or the width of a vertical heater). In certain embodiments, the ratio of the largest transverse cross-sectional dimension to wellbore diameter may be selected to be less than about 1:2, less than about 1:3, or less than about 1:4. The ratio of heater diameter to wellbore diameter may be chosen to inhibit contact and/or deformation of the heater by the formation (i.e., inhibit closing in of the wellbore on the heater) during heating. In certain embodiments, the wellbore diameter may be determined by a diameter of a drillbit used to form the wellbore.

In an embodiment, a wellbore diameter may shrink from an initial value of about 16.5 cm to about 6.4 cm during heating of a formation (e.g., for a wellbore in hydrocarbon containing layer with a richness greater than about 0.12 L/kg). At some point, expansion of formation material into the wellbore during heating results in a balancing between the hoop stress of the wellbore and the compressive strength due to thermal expansion of hydrocarbon, or kerogen, rich layers. At this point, the formation may no longer have the strength to deform or collapse a heater, or a liner. For example, the radial stress provided by formation material may be about 12,000 psi (82.7 MPa) at a diameter of about 16.5 cm, while the stress at a diameter of about 6.4 cm after expansion may be about 3000 psi (20.7 MPa). A heater diameter may be selected to be less than about 3.8” to inhibit contact of the formation and the heater. A temperature limited heater may advantageously provide a higher heat output over a significant portion of the wellbore (e.g., the heat output needed to provide sufficient heat to pyrolyze hydrocarbons in a hydrocarbon containing formation) than a constant wattage heater for smaller heater diameters (e.g., less than about 5.1”).

In certain embodiments, a heater may be placed in a deformation resistant container. The deformation resistant container may provide additional protection for inhibiting deformation of a heater. The deformation resistant container may have a higher creep-rupture strength than a heater. In one embodiment, a deformation resistant container may have a creep-rupture strength of at least about 3000 psi (20.7 MPa) at 100,000 hours for a temperature of about 650 °C. In some embodiments, the creep-rupture strength of a deformation resistant container may be at least about 4000 psi (27.7 MPa) at 100,000 hours, or at least about 5000 psi (34.5 MPa) at 100,000 hours for a temperature of about 650 °C. In an embodiment, a deformation resistant container may include one or more alloys that provide mechanical strength. For example, a deformation resistant container may include an alloy of iron, nickel, chromium, manganese, carbon, tantalum, and/or mixtures thereof.

FIG. 13 depicts radial stress and conduit (e.g., a liner) collapse strength versus remaining wellbore diameter and conduit outside diameter in an hydrocarbon containing formation. The calculations for radial stress were done for a 52 gallon per ton oil shale from the Green River. The heating rate was about 820 watts per meter. Plot 166 depicts maximum radial stress from the oil shale versus remaining diameter for an initial wellbore diameter of 6.5 inches. Plot 168 depicts liner collapse strength versus liner outside diameter for Schedule 80 347H stainless steel pipe at 650 °C. Plot 170 depicts liner collapse strength versus liner outside diameter for Schedule 160 347H stainless steel pipe at 650 °C. Plot 172 depicts liner collapse strength versus liner outside diameter for Schedule XXH 347H stainless steel conduit at 650 °C. Plots 168, 170, and 172 show that increasing the thickness of the liner increases the collapse strength and that a Schedule XXH 347H stainless steel liner may have sufficient collapse strength to withstand the maximum radial stress from the oil shale at 650 °C. The conduit collapse strength should be greater than the maximum radial stress to inhibit deformation of the conduit.

FIG. 14 depicts radial stress and conduit collapse strength versus a ratio of conduit outside diameter to initial wellbore diameter in an hydrocarbon containing formation. Plot 174 depicts radial stress from oil shale versus the ratio of conduit outside diameter to initial wellbore diameter. Plot 174 shows that the radial stress from the oil shale decreased rapidly from ratios of 1 down to a ratio of about 0.85. Below a ratio of 0.8, the radial stress slowly decreased. Plot 176 depicts conduit collapse strength versus the ratio of conduit outside diameter to initial wellbore diameter for a Schedule XXH 347H stainless steel conduit. Plot 178 depicts conduit collapse strength versus the ratio of conduit outside diameter to initial wellbore diameter for a Schedule 160 347H stainless steel conduit. Plot 180 depicts conduit collapse strength versus the ratio of conduit outside diameter to initial wellbore diameter for a Schedule 80 347H stainless steel conduit. Plot 182 depicts conduit collapse strength versus the ratio of conduit outside diameter to initial wellbore diameter for a Schedule 40 347H stainless steel conduit. Plot 184 depicts conduit collapse strength versus the ratio of conduit outside diameter to initial wellbore diameter for a Schedule 10 347H stainless steel conduit. The plots in FIG. 14 show that below a ratio of conduit outside diameter to initial wellbore diameter of 0.75, a Schedule XXH 347H stainless steel conduit has sufficient collapse strength to withstand radial stress from the oil shale. FIG. 14 and other similar plots may be used to design an initial wellbore diameter and the materials and outside diameter of a conduit so that deformation of the conduit may be inhibited.

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

WHAT IS CLAIMED IS:

1. A method for treating a hydrocarbon containing formation, comprising:

heating a first volume of the formation using a first set of heaters; and

heating a second volume of the formation using a second set of heaters, wherein the first volume is spaced apart from the second volume by a third volume of the formation, and wherein the first volume, second volume, and third volume are sized, shaped, and/or located to inhibit deformation of subsurface equipment caused by geomechanical motion of the formation during heating.

2. The method of claim 1, further comprising allowing the heat to transfer from the first and second volumes of the formation to at least a part of the formation.

3. The method of any one of claims 1-2, further comprising sizing, shaping, and/or locating a footprint of the first volume, second volume, and/or third volume based on, at least in part, a calculated geomechanical motion of at least a portion of the formation.

4. The method of any one of claims 1-3, further comprising calculating geomechanical motion in a footprint of the first volume or the second volume, and using the calculated geomechanical motion to size, shape, and/or locate the first volume, the second volume, and/or the third volume.

5. The method of any one of claims 3-4, wherein the first, second, and/or third volumes have been sized to inhibit deformation of one or more selected wellbores and/or subsurface equipment caused by geomechanical motion of the formation during heating.

6. The method of any one of claims 1-5, wherein the third volume substantially surrounds the first volume, and the second volume substantially surrounds the first volume.

7. The method of any one of claims 1-6, wherein the third volume substantially surrounds all or a portion of the first volume, and the second volume substantially surrounds all or a portion of the third volume.

8. The method of any one of claims 1-7, wherein the third volume has a footprint that is a linear, curved, or irregular shaped strip.

9. The method of any one of claims 1-8, wherein the first, second, and/or third volumes comprise rectangular footprints, square footprints, or circular footprints.

10. The method of any one of claims 1-9, wherein the first, second, and/or third volumes comprise footprints in a concentric ring pattern.

11. The method of any one of claims 1-10, wherein the first, second, and/or third volumes of the formation have been sized, shaped, or located, at least in part, based on a simulation.

12. The method of any one of claims 1-11, wherein a footprint area of the first volume, second volume, and/or third volume is less than about 400 square meters.

13. The method of any one of claims 1-12, further comprising heating with the third set of heaters after a selected amount of geomechanical motion in the first or second volumes.

14. The method of any one of claims 1-13, further comprising heating with the third set of heaters to maintain or enhance a production rate of a mixture from the formation.

15. The method of any one of claims 1-14, further comprising heating with the third set of heaters about 6 months after the first set or second set of heaters begin heating.

16. The method of any one of claims 1-15, further comprising maintaining a temperature in at least a portion of the formation in a pyrolysis temperature range with a lower pyrolysis temperature of about 250°C and an upper pyrolysis temperature of about 400°C.

17. The method of any one of claims 1-16, further comprising pyrolyzing at least some of the hydrocarbons in the formation.

18. The method of any one of claims 1-17, further comprising controlling a pressure and a temperature in at least a part of the formation, wherein the pressure is controlled as a function of temperature, or the temperature is controlled as a function of pressure.

19. The method of any one of claims 1-18, further comprising allowing the heat to transfer from the first and second volumes of the formation to at least a part of the formation, and producing a mixture from the formation.

20. The method of claim 19, wherein the produced mixture comprises condensable hydrocarbons having an API gravity of at least bout 25°.

21. The method of any one of claims 1-20, further comprising controlling formation conditions such that the produced mixture comprises a partial pressure of H_2 in the mixture greater than about 0.5 bars.

22. The method of any one of claims 1-21, further comprising controlling a pressure in at least a part of the formation, wherein the controlled pressure is at least about 2.0 bars absolute.

23. The method of any one of claims 1-22, wherein the formation comprises an oil shale formation or a coal formation.

24. A method for treating a hydrocarbon containing formation, comprising:

heating a first volume of the formation using a first set of heaters;

heating a second volume of the formation using a second set of heaters, wherein the first volume is spaced apart from the second volume by a third volume of the formation;

heating the third volume using a third set of heaters, wherein the third set of heaters begins heating at a selected time after the first set of heaters and the second set of heaters;

allowing the heat to transfer from the first volume, the second volume, and the third volume of the formation to at least a part of the formation; and

producing a mixture from the formation.

25. The method of claim 24, wherein the first volume, the second volume, or the third volume are sized, shaped, or located based on, at least in part, a calculated geomechanical motion of at least a portion of the formation.

26. The method of claim 24, further comprising sizing, shaping, or locating the first volume, the second volume, or the third volume based on, at least in part, a calculated geomechanical motion of at least a portion of the formation.

27. The method of claim 24, wherein the first volume, the second volume, or the third volume are sized, shaped, or located, at least in part, to inhibit deformation, caused by geomechanical motion, of one or more selected wellbores in the formation.

28. The method of claim 24, wherein the first volume, the second volume, or the third volume are at least in part sized, shaped, or located based on a calculated geomechanical motion of at least a portion of the formation, and wherein the first volume, the second volume, or the third volume are sized,

shaped, or located, at least in part, to inhibit deformation caused by geomechanical motion of one or more selected wellbores in the formation.

29. The method of claim 24, wherein the first volume, the second volume, or the third volume of the formation has been sized, shaped, or located, at least in part, based on a simulation.

30. The method of claim 24, wherein a footprint area of the first volume, the second volume, or the third volume is less than about 400 square meters.

31. The method of claim 24, wherein the third set of heaters begins heating after a selected amount of geomechanical motion in the first volume or the second volume.

32. The method of claim 24, wherein the third set of heaters begins heating to maintain or enhance a production rate of the mixture from the formation.

33. The method of claim 24, wherein the selected time has been at least in part determined using a simulation.

34. The method of claim 24, wherein the first volume and the second volume comprise rectangular footprints.

35. The method of claim 24, wherein the first volume and the second volume comprise square footprints.

36. The method of claim 24, wherein the first volume and the second volume comprise circular footprints.

37. The method of claim 24, wherein the first volume, the second volume, and the third volume comprise rectangular footprints.

38. The method of claim 24, wherein the first volume, the second volume, and the third volume comprise square footprints.

39. The method of claim 24, wherein the first volume, the second volume, and the third volume comprise circular footprints.

40. The method of claim 24, wherein the first volume, the second volume, and the third volume comprise footprints in a concentric ring pattern.

41. The method of claim 24, further comprising maintaining a temperature in at least a portion of the formation in a pyrolysis temperature range with a lower pyrolysis temperature of about 250°C and an upper pyrolysis temperature of about 400°C.

42. The method of claim 24, further comprising pyrolyzing at least some of the hydrocarbons in the formation.

43. The method of claim 24, further comprising controlling a pressure and a temperature in at least a majority of the part of the formation, wherein the pressure is controlled as a function of temperature, or the temperature is controlled as a function of pressure.

44. The method of claim 24, wherein the produced mixture comprises condensable hydrocarbons having an API gravity of at least about 25°.

45. The method of claim 24, further comprising controlling a pressure in at least a majority of a part of the formation, wherein the controlled pressure is at least about 2.0 bars absolute.

46. The method of claim 24, further comprising controlling formation conditions such that the produced mixture comprises a partial pressure of H_2 in the mixture greater than about 0.5 bars.

47. The method of claim 24, wherein the third set of heaters begins heating about 6 months after the first set of heaters or the second set of heaters begins heating.

48. The method of claim 24, wherein the formation comprises an oil shale formation.

49. The method of claim 24, wherein the formation comprises a coal formation.

50. A method for treating a hydrocarbon containing formation, comprising:

heating a first volume of the formation using a first set of heaters; and

heating a second volume of the formation using a second set of heaters, wherein the first volume is spaced apart from the second volume by a third volume of the formation; and

sizing, shaping, and/or locating the first volume, the second volume, and the third volume to inhibit deformation of subsurface equipment caused by geomechanical motion of the formation during heating.

51. The method of claim 50, wherein sizing, shaping or locating the first volume, the second volume, and the third volume is based on, at least in part, calculated geomechanical motion of at least a portion of the formation.

52. The method of claim 50, wherein the first volume and the second volume comprise footprints in a concentric ring pattern.

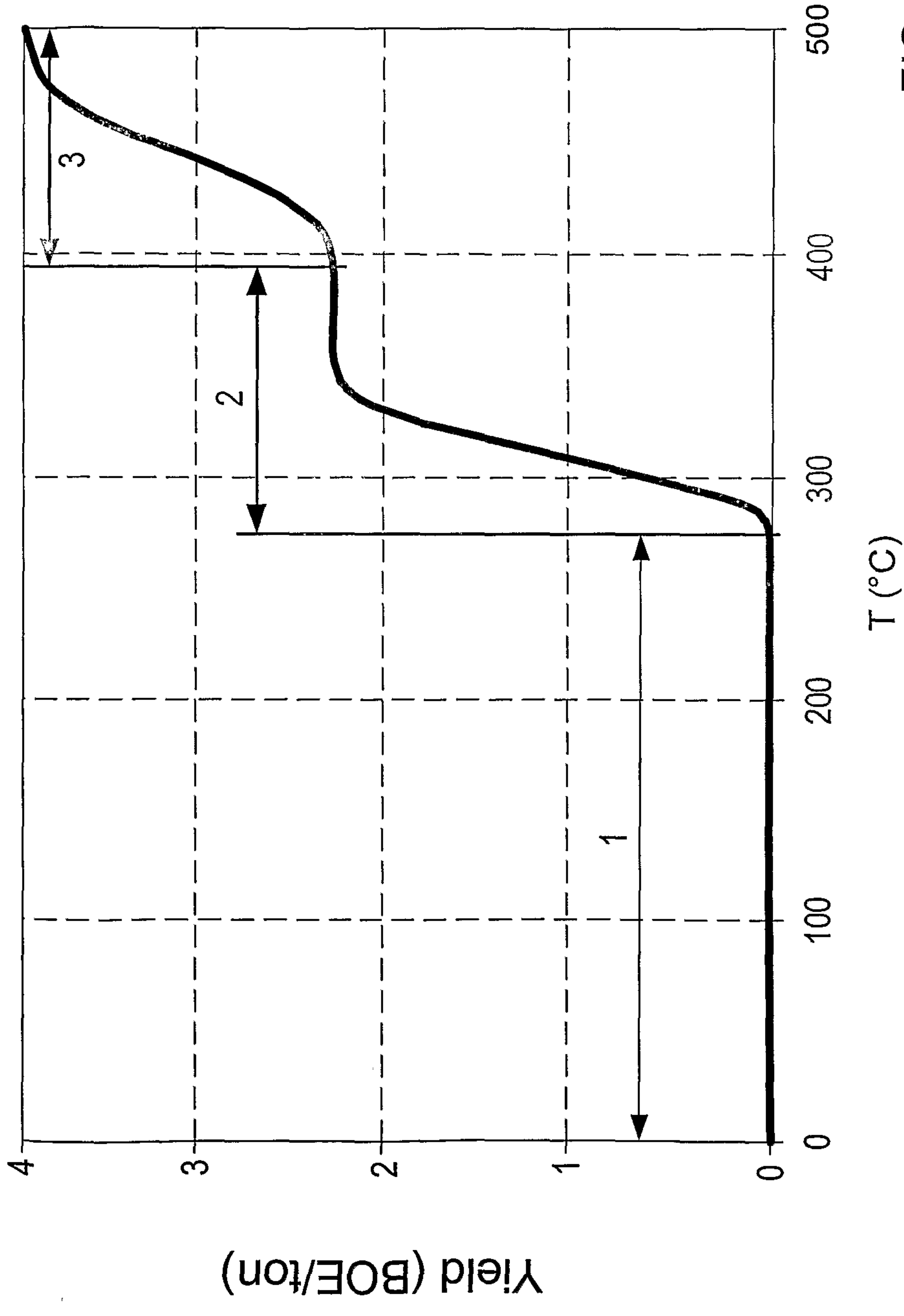


FIG. 1

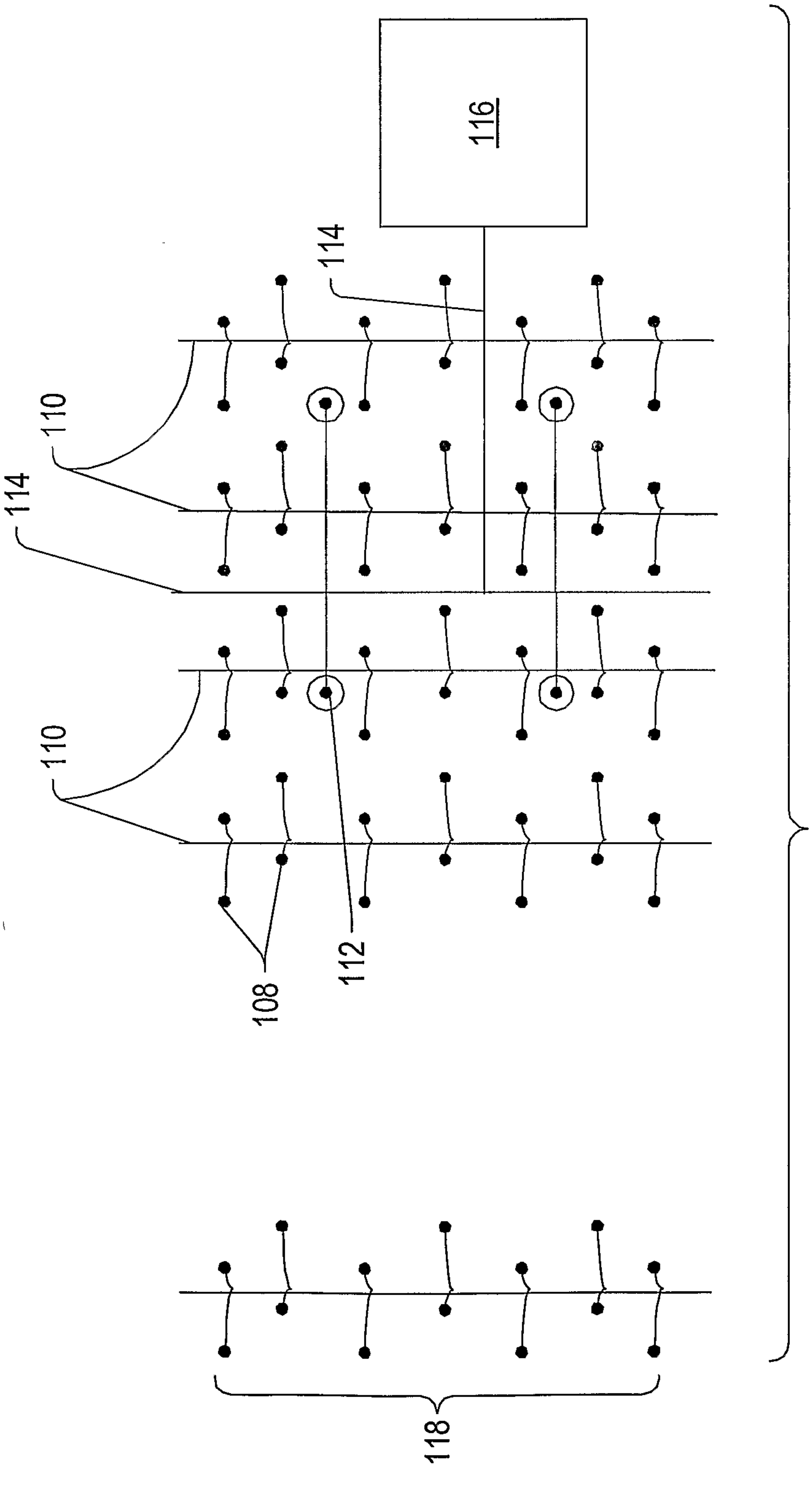


FIG. 2

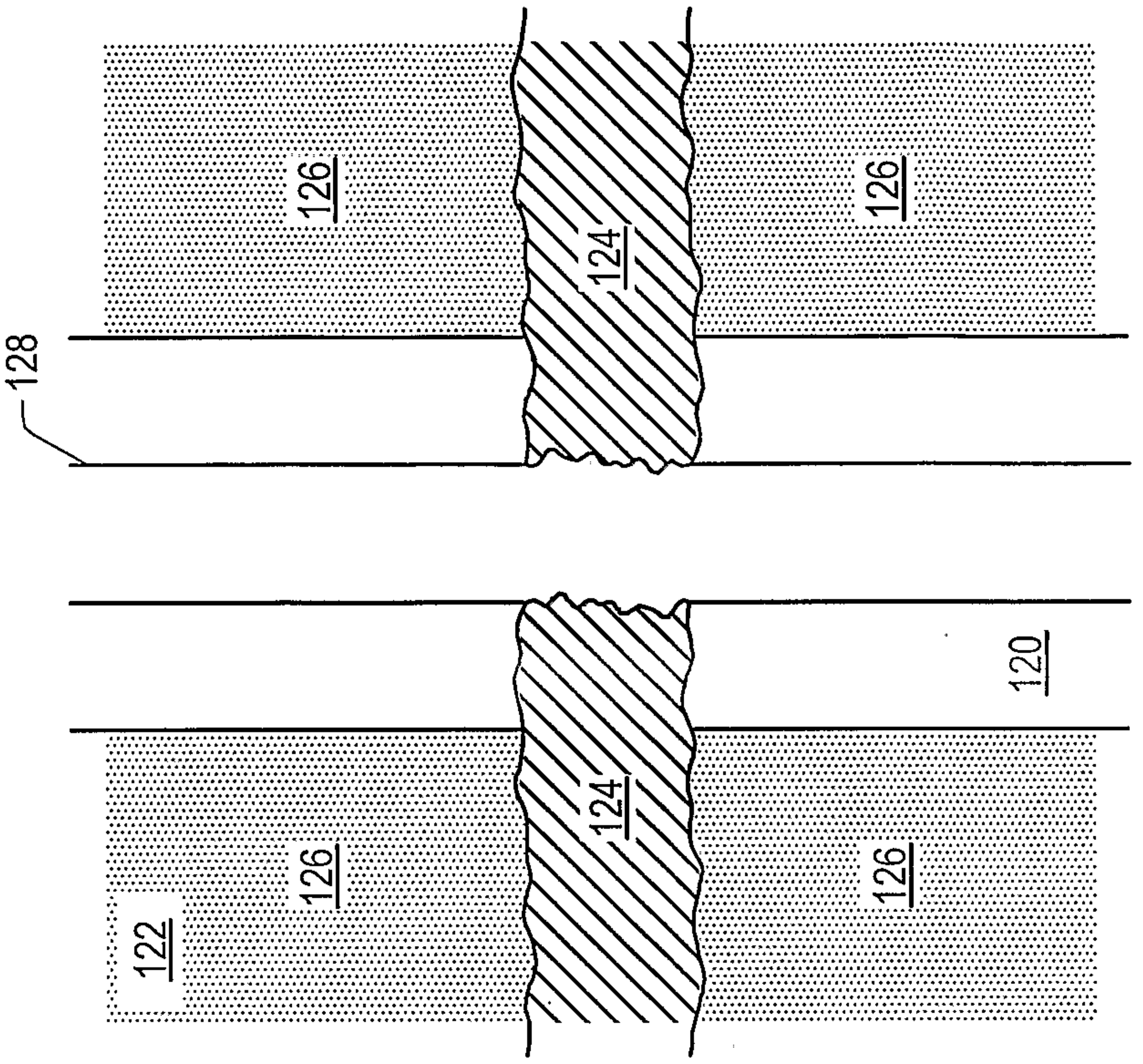

126
126
124
128
120
124
126
126
122

FIG. 4

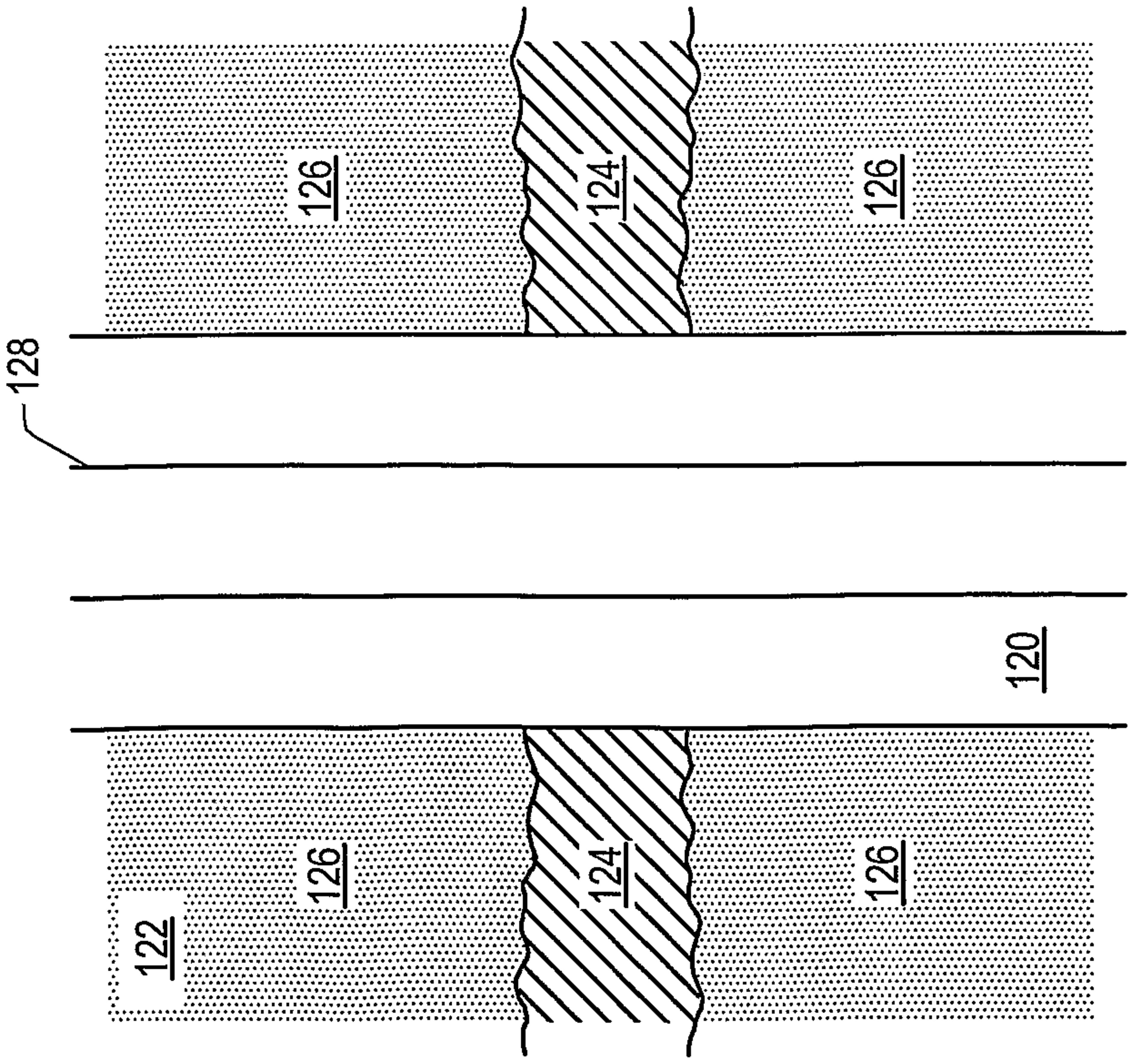

126
126
124
128
120
124
126
126
122

FIG. 3

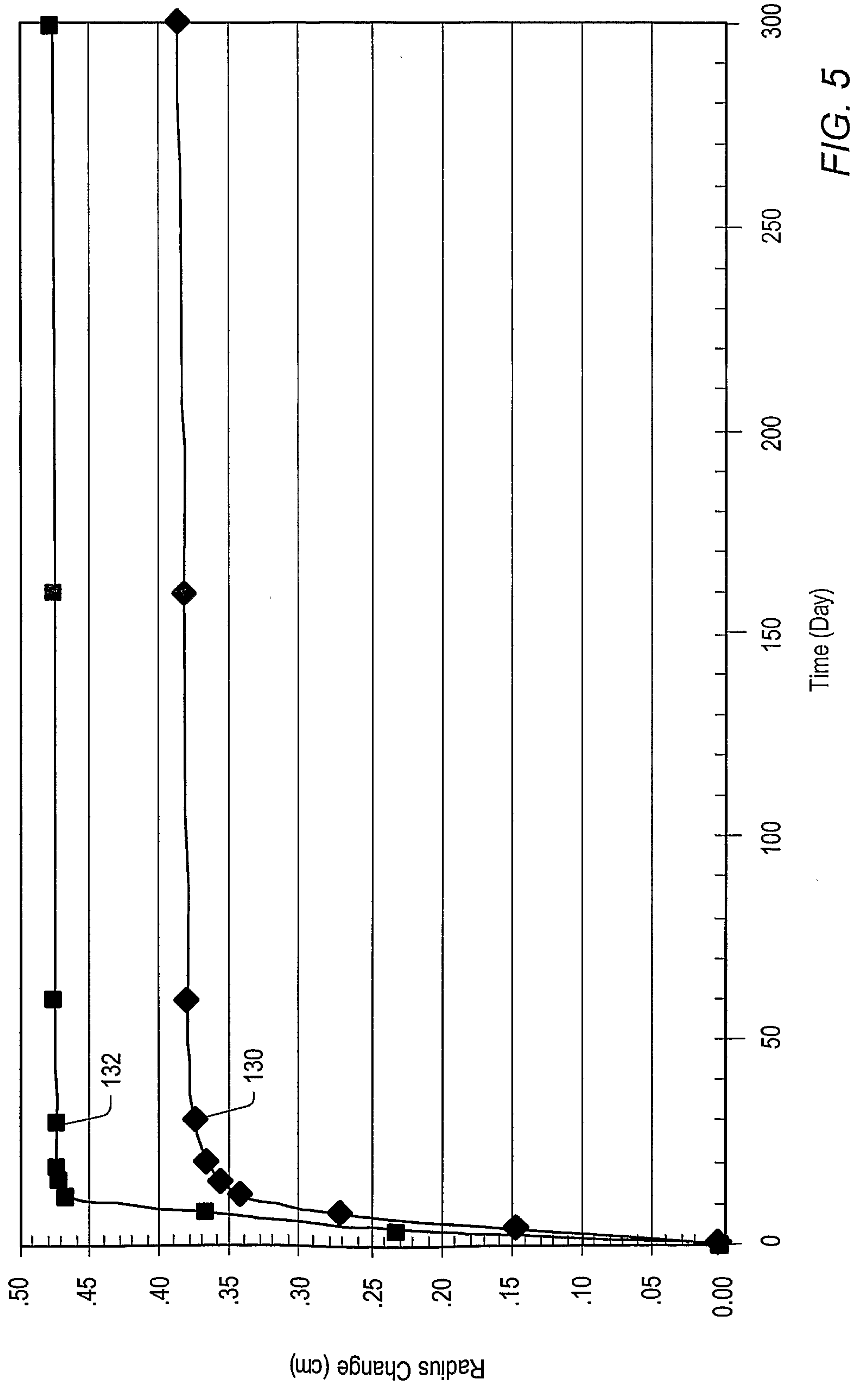

Radius Change (cm)
0.00
.05
.10
.15
.20
.25
.30
.35
.40
.45
.50
Time (Day)
0
50
100
150
200
250
300
130
132

FIG. 5

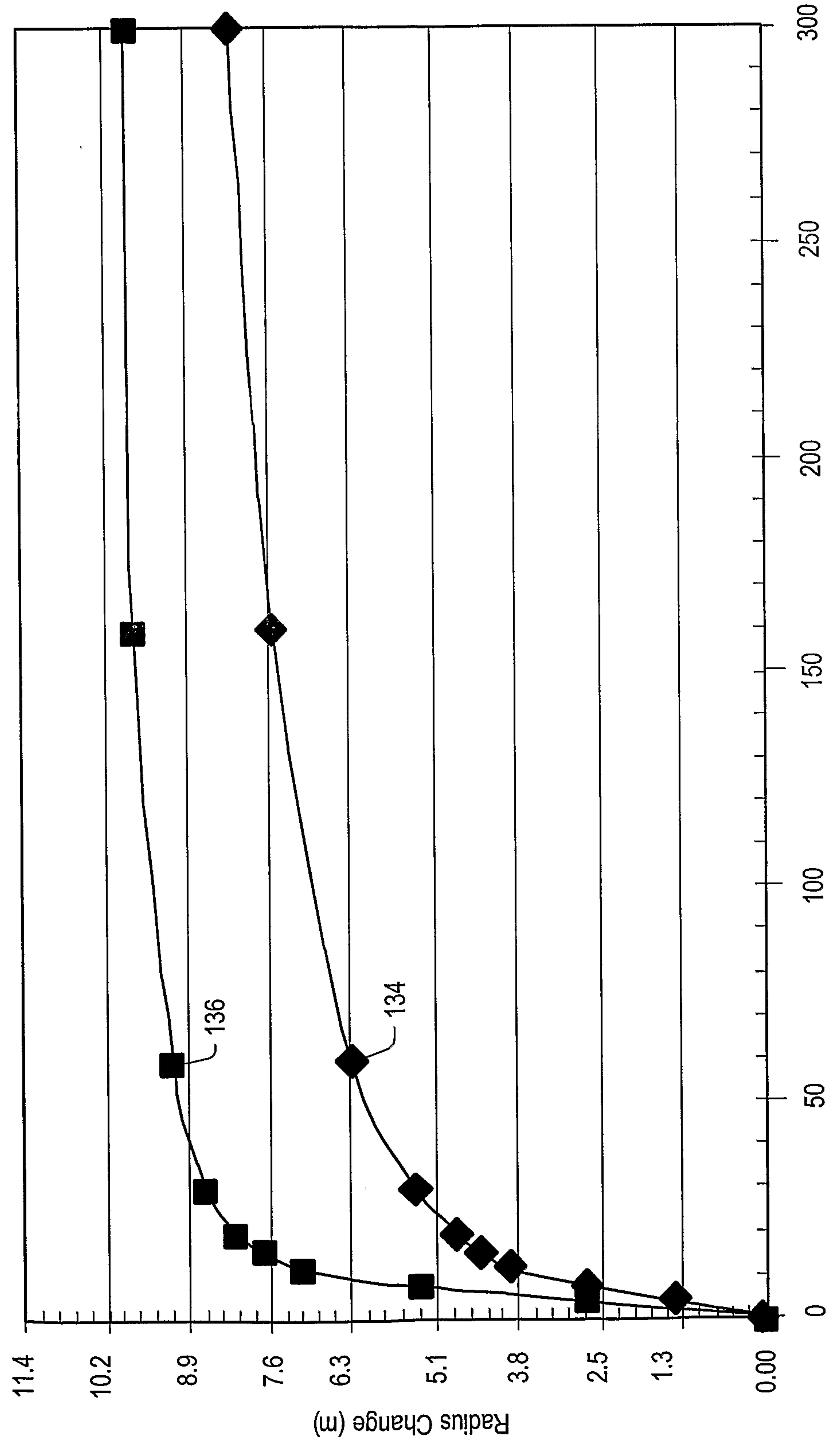

11.4
10.2
8.9
7.6
6.3
5.1
3.8
2.5
1.3
0.00
Radius Change (m)
0
50
100
150
200
250
300
Time (Day)
136
134

FIG. 6

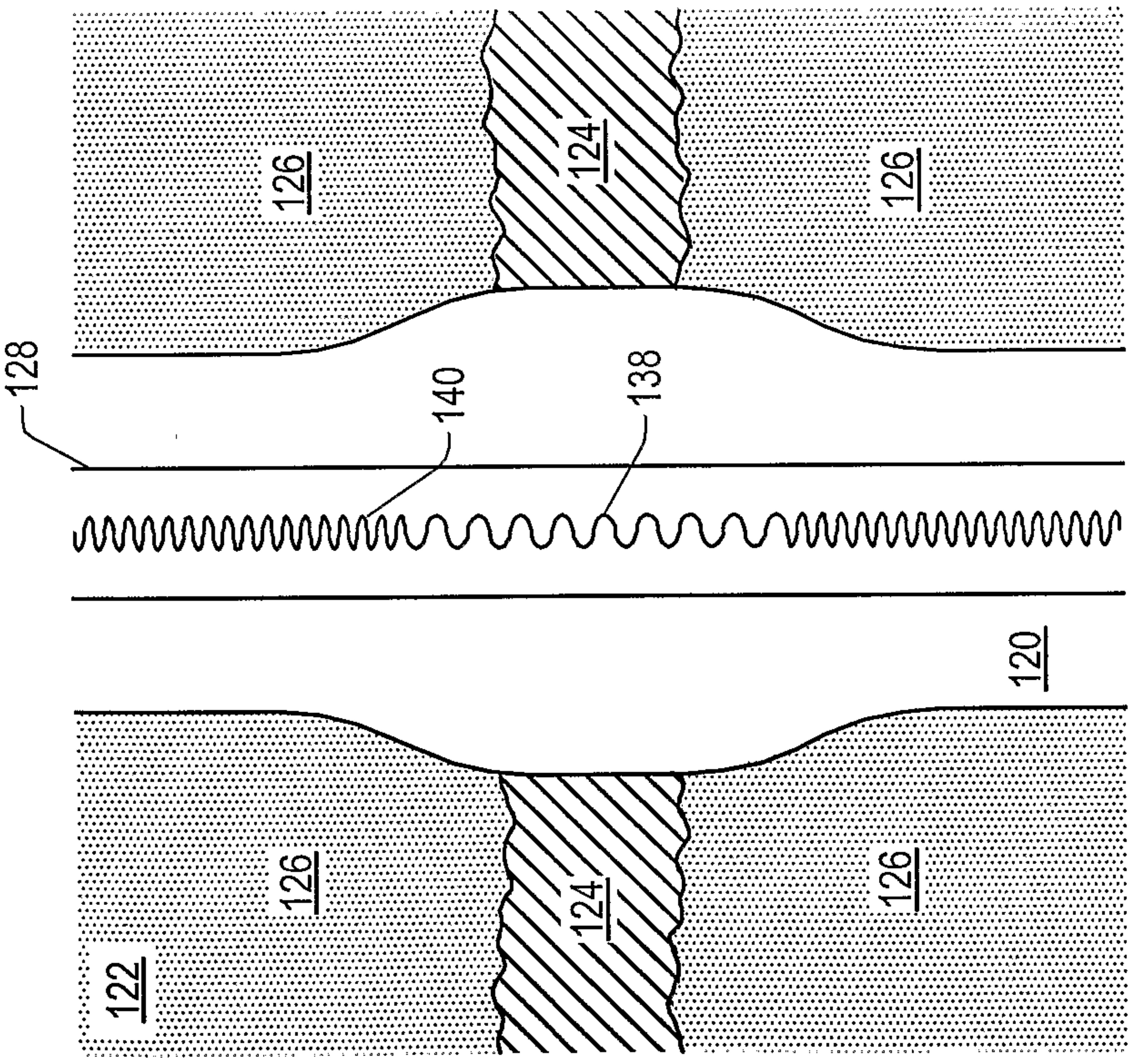


FIG. 7

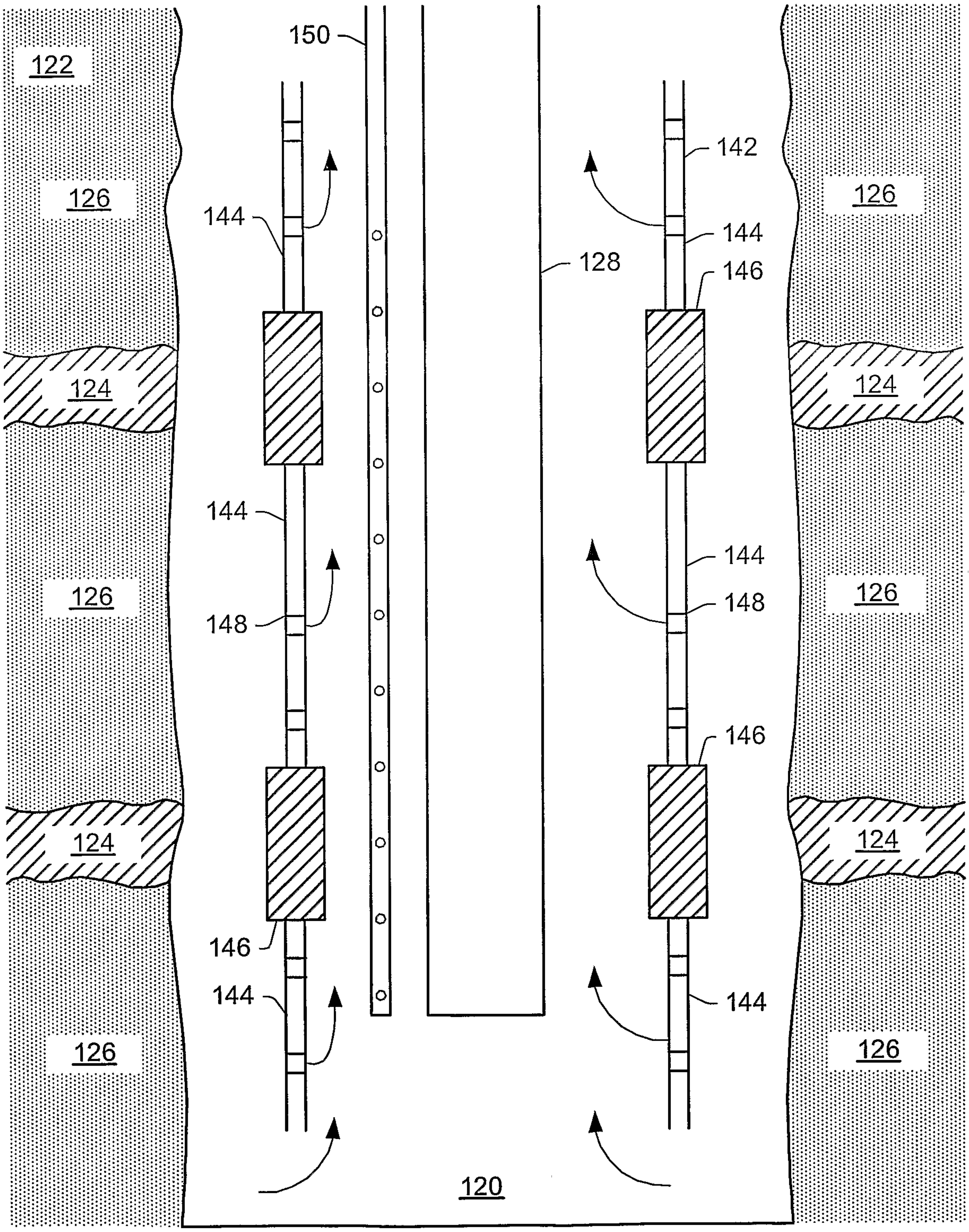


FIG. 8

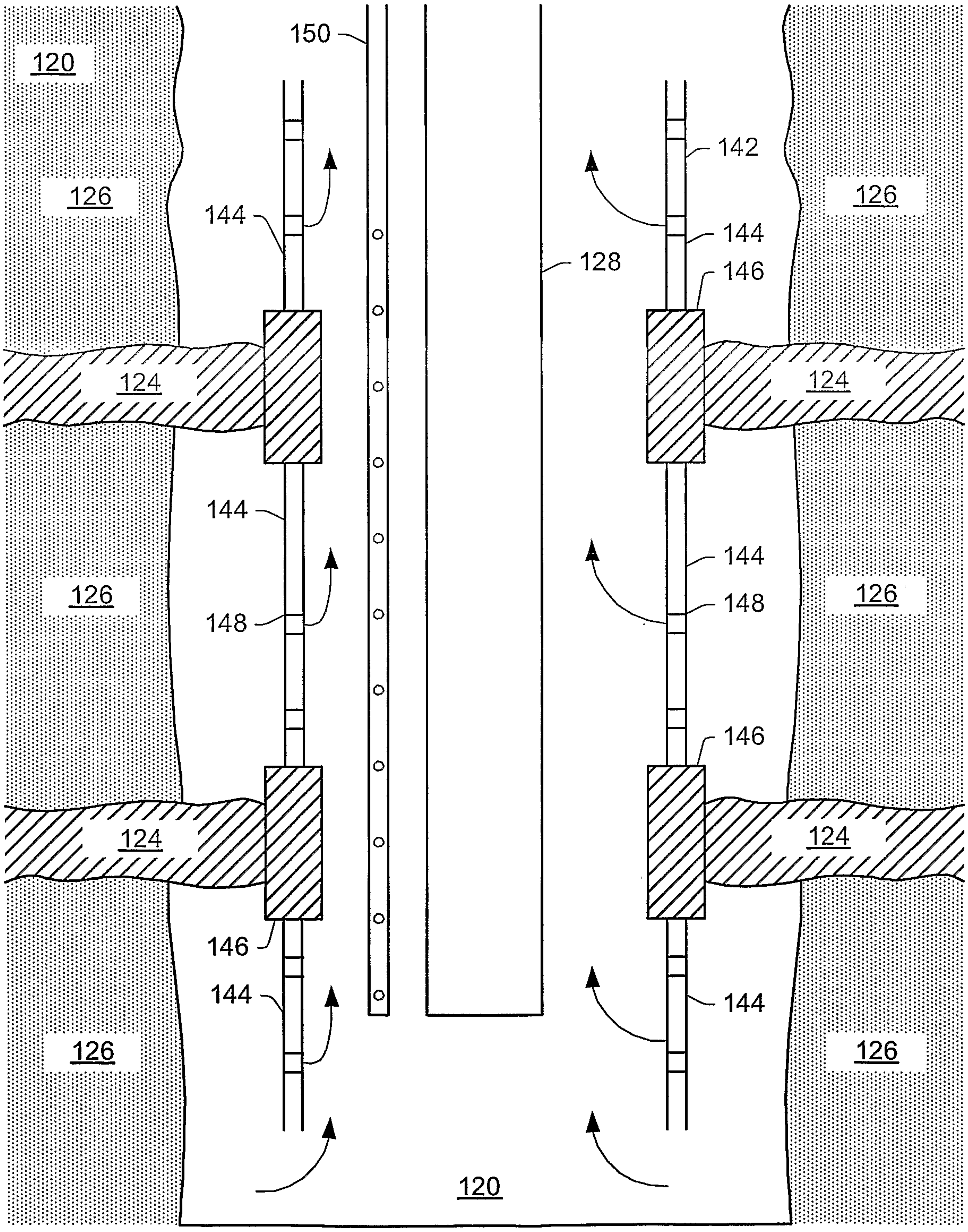

150
120
142
126
126
144
144
128
146
124
124
144
144
126
126
148
148
146
124
124
146
144
144
126
126
120

FIG. 9

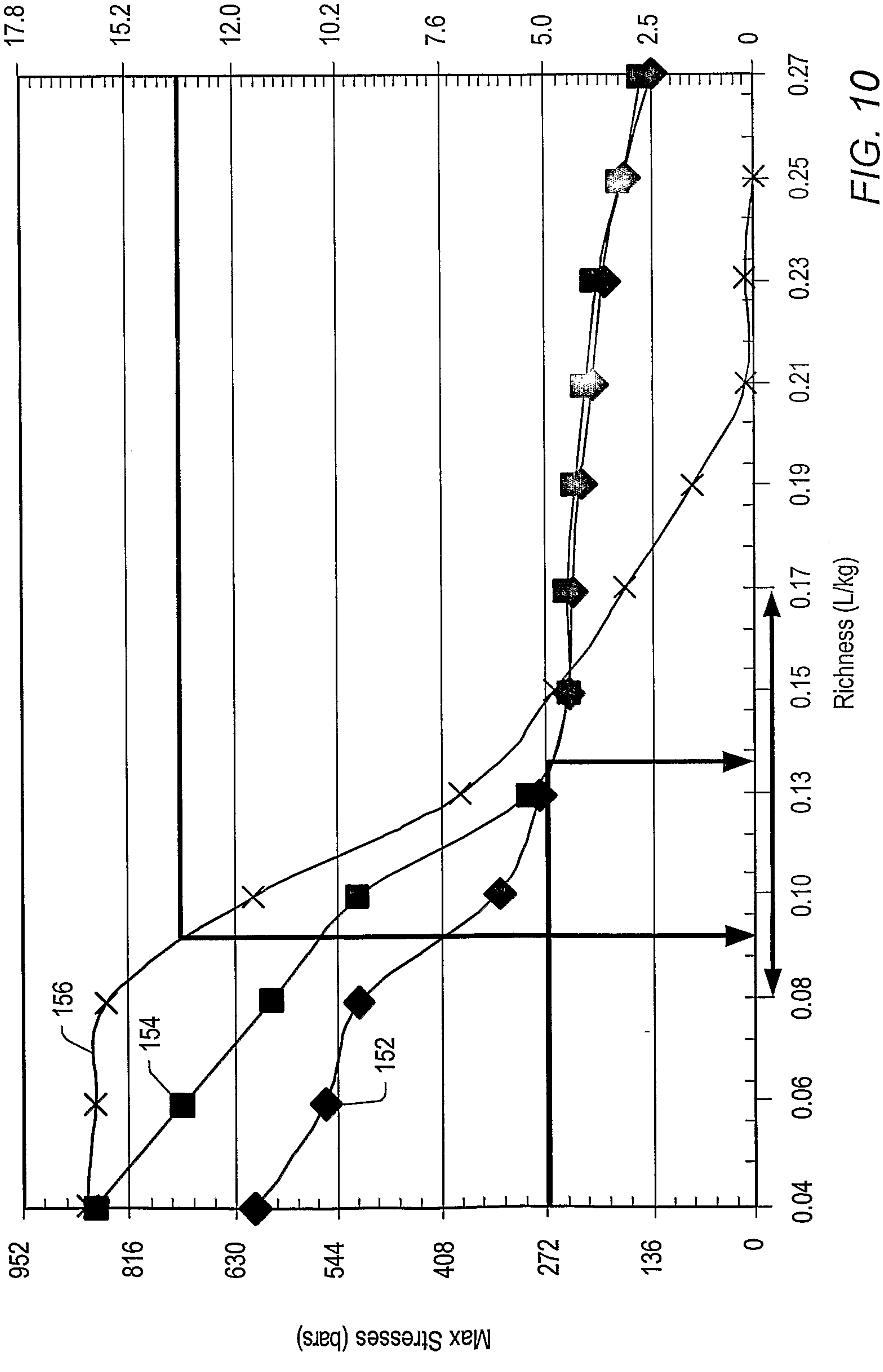

Max Stresses (bars)
952
816
630
544
408
272
136
0
17.8
15.2
12.0
10.2
7.6
5.0
2.5
0
0.04
0.06
0.08
0.10
0.13
0.15
0.17
0.19
0.21
0.23
0.25
0.27
Richness (L/kg)
156
154
152

FIG. 10

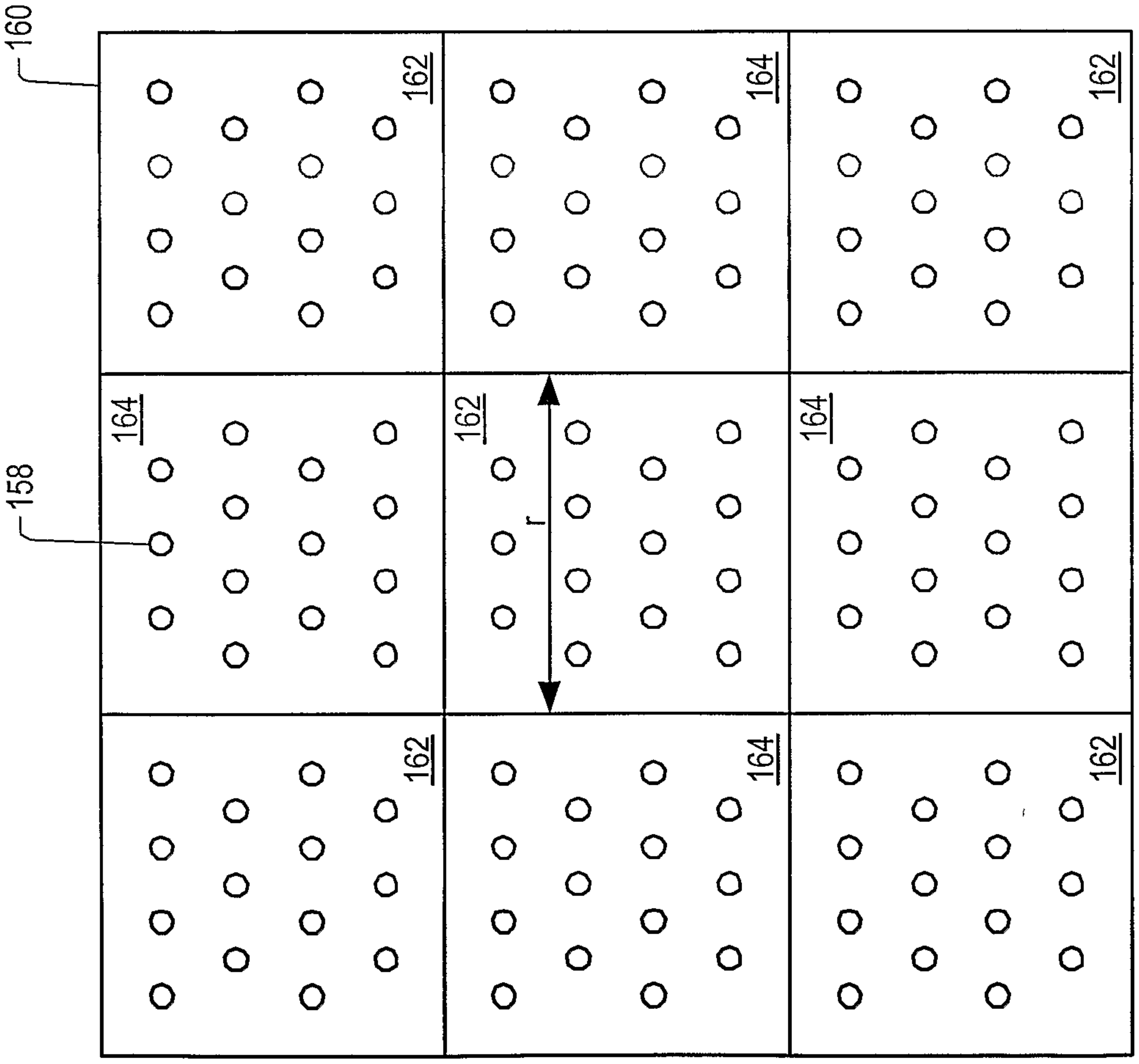


FIG. 11

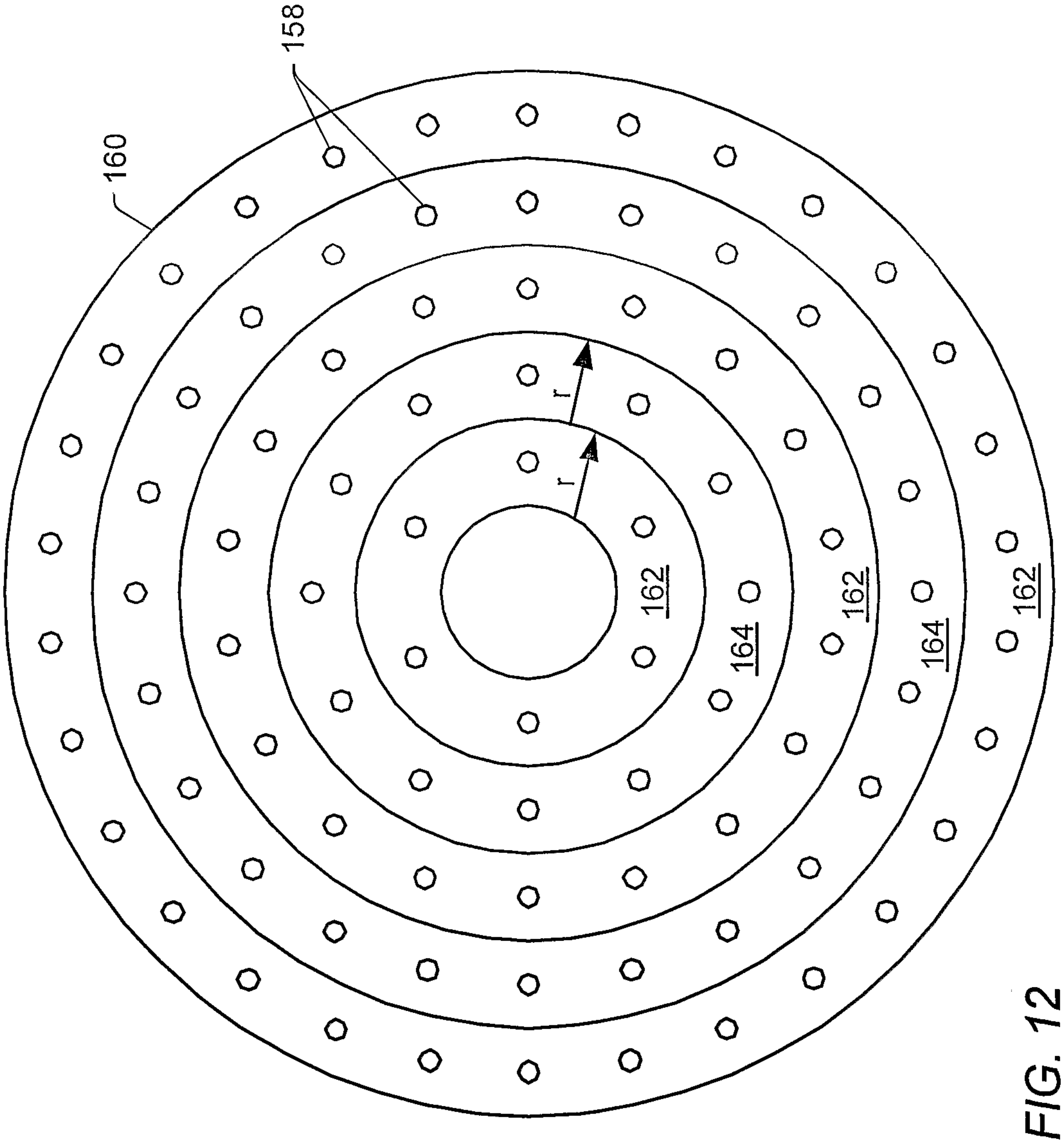


FIG. 12

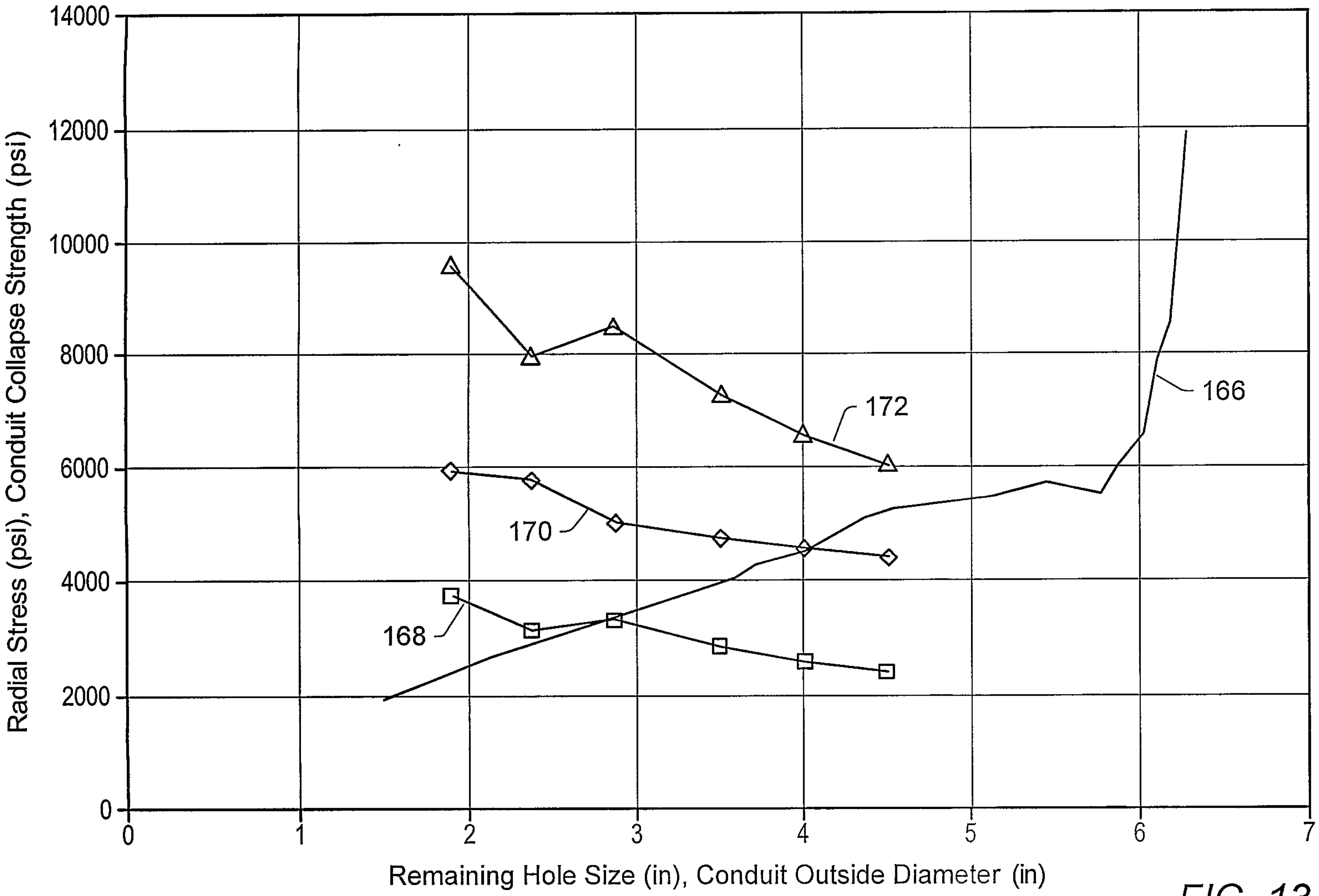

14000
12000
10000
8000
6000
4000
2000
0
Radial Stress (psi), Conduit Collapse Strength (psi)
0
1
2
3
4
5
6
7
Remaining Hole Size (in), Conduit Outside Diameter (in)
166
168
170
172

FIG. 13

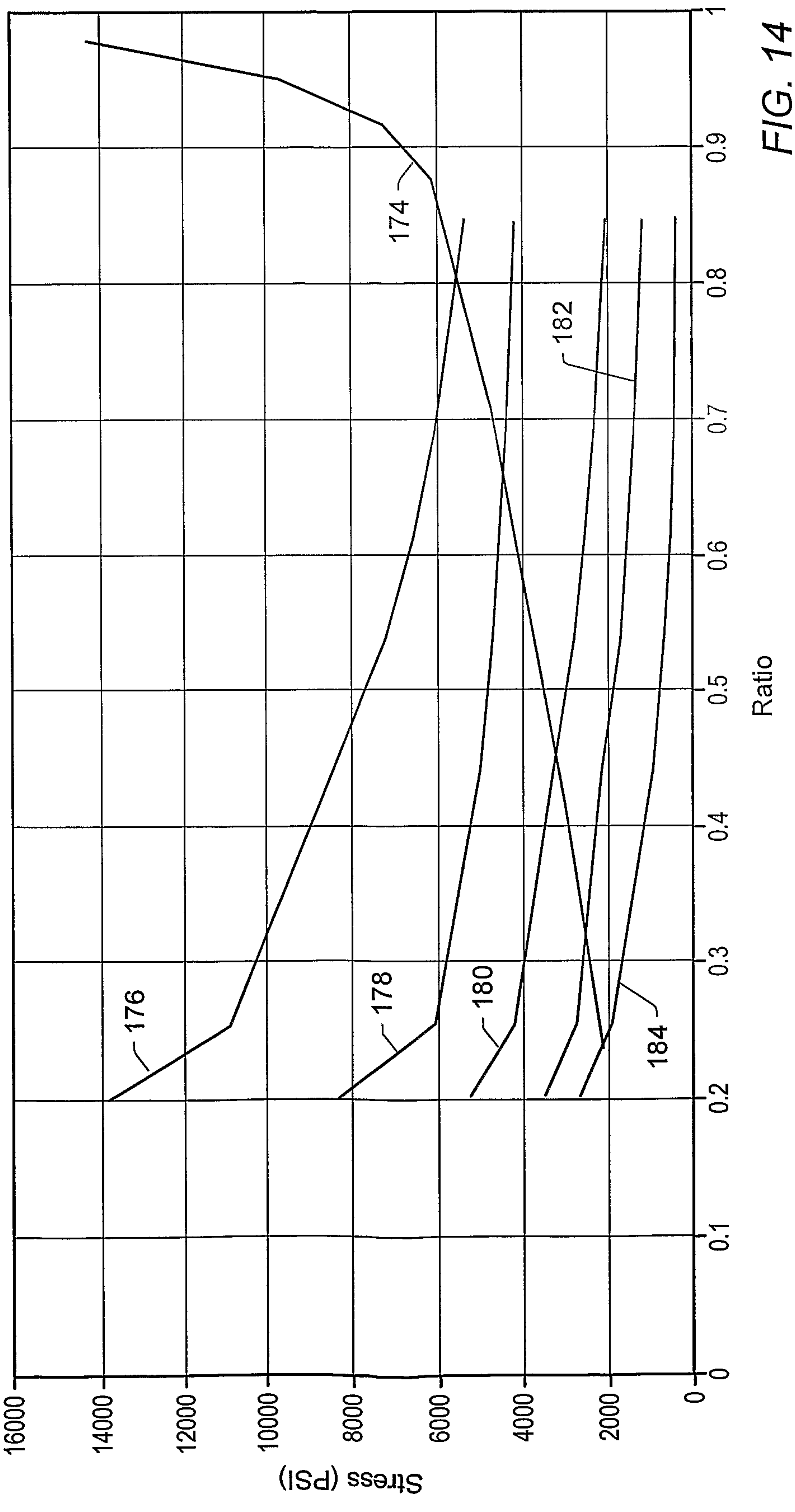
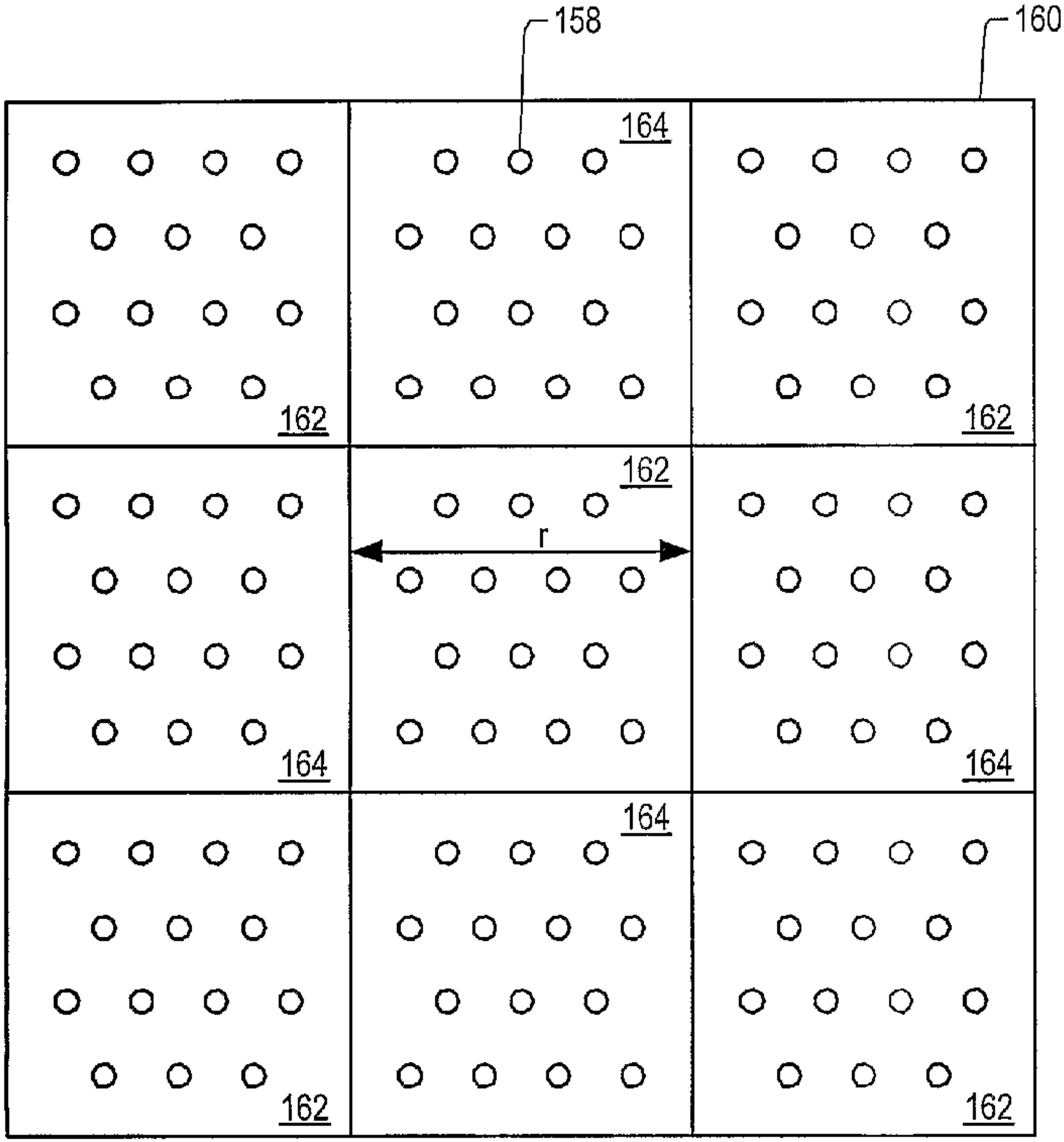

Stress (PSI)
16000
14000
12000
10000
8000
6000
4000
2000
0
Ratio
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
174
176
178
180
182
184

FIG. 14


158
160
164
162
162
162
r
164
164
164
162
162