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(54) Title: IN SITU THERMAL PROCESSING OF A HYDROCARBON CONTAINING FORMATION TO PRODUCE HEATED FLUIDS

(57) Abstract: A process for utilizing the heat from fluids produced from a hydrocarbon containing formation, which has been treated in situ. The in situ treatment process may include providing heat from one or more heaters to at least a portion of the formation. The heat may be allowed to transfer from one or more heaters to a part of the formation such that heat from the one or more heaters pyrolyzes at least some hydrocarbons within the part of the formation. Hydrocarbons may be produced from the formation. In an embodiment, heat from the produced fluids may be used for other processes. Examples of other processes may include, but are not limited to, hydrotreating, separations, steam cracking, olefin production, etc.



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IN SITU THERMAL PROCESSING OF A HYDROCARBON CONTAINING FORMATION TO PRODUCE HEATED FLUIDS

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BACKGROUND OF THE INVENTION

1. Field of the Invention

The present invention relates generally to methods and systems for production of hydrocarbons, hydrogen, and/or other products from various hydrocarbon containing formations. Certain embodiments relate to in situ conversion of hydrocarbons to produce hydrocarbons, hydrogen, and/or novel product streams from underground hydrocarbon containing formations. In an embodiment, the present invention relates to using heat from the produced fluids for other processes. Examples of other processes may include, but are not limited to, hydrotreating, separations, steam cracking, olefin production, etc.

15 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.

Formation fluids may undergo treatment processes in a first in situ treatment area as the formation fluid is generated and produced, in a second in situ treatment area where a specific treatment process occurs, and/or in surface treatment units. Surface facility configurations may vary dramatically due to a composition of formation fluid as well as the products being generated. Surface treatment units may require energy (e.g., heat) for treatment and/or transportation of produced formation fluids. The energy may be produced on site or purchased from outside sources and may be economically unfavorable. Thus, the utilization of the energy from the formation fluids in the surface treatment units may be more economically favorable.

SUMMARY OF THE INVENTION

35 In an embodiment, hydrocarbons within a hydrocarbon containing formation (e.g., a formation containing coal, oil shale, heavy hydrocarbons, or a combination thereof) may be converted in situ within the formation to yield a mixture of relatively high quality hydrocarbon products, hydrogen, and/or other products. One or more heaters may be used to heat a portion of the hydrocarbon containing formation to temperatures that allow pyrolysis of the hydrocarbons. Hydrocarbons, hydrogen, and other formation fluids may be removed from the formation through one or more production wells. In some embodiments, formation fluids may be removed in a vapor phase. In other embodiments, formation fluids may be removed in liquid and vapor phases or in a liquid phase.

Temperature and pressure in at least a portion of the formation may be controlled during pyrolysis to yield improved products from the formation.

In an embodiment, a method of treating a hydrocarbon containing formation in situ may include providing heat from one or more heaters to at least a portion of the formation. The heat provided from at least one heater may be transferred to the formation substantially by conduction. The method may include allowing the heat to transfer from at least the portion to a part of the formation. In addition, the method may include producing fluids from the part of the formation. At least a portion of the produced fluids may have been heated by the heat provided by one or more heaters. At least a portion of the produced fluids may be produced at a temperature greater than about 200 °C, about 250 °C or about 300 °C. The heat of the produced fluids may be used in other processes as described herein. A portion of the produced fluids may be treated without using a surface heater to heat the produced fluids.

In an embodiment, a portion of the produced fluids may be provided to a treatment facility using insulated conduits. The insulated conduits may inhibit heat loss from the produced fluids. In other embodiments, a portion of the produced fluids may be provided to a treatment facility using heated conduits. In some embodiments, a method of treating a hydrocarbon containing formation in situ may include removing heat from the produced fluids in a heat exchanger.

In some embodiments, a method of treating a hydrocarbon containing formation in situ may include varying the heat provided to the one or more heaters to vary heat in at least a portion of the produced fluids. In certain embodiments the produced fluids may be produced from a well including at least one of the heaters. When the produced fluids are provided from a wellhead, a portion of the produced fluids may be provided to a treatment facility at a temperature that is within about 50 °C of the temperature of the produced fluids at the wellhead.

In an embodiment, a method of treating a hydrocarbon containing formation in situ may include providing at least a portion of the produced fluids to a hydrotreating unit. At least a portion of the produced fluids may be hydrotreated such that the volume of hydrotreated produced fluids is about 4% greater than a volume of the produced fluids. The produced fluids may include molecular hydrogen. The molecular hydrogen may be used to hydrotreat a portion of the produced fluids. At least 50% of the molecular hydrogen used to hydrotreat the produced fluids may be provided by the produced fluids. In other embodiments, molecular hydrogen in the produced fluids may be separated from the produced fluids. Molecular hydrogen separated from produced fluids may be provided, for example, to a surface treatment unit or an in situ treatment unit.

In an embodiment, a method of treating a hydrocarbon containing formation in situ may include providing at least a portion of the produced fluids to an olefin generating unit, a separating unit, a distillation column, and/or a steam cracking unit.

Produced fluids may be separated into two or more streams. The two or more streams may include at least a synthetic condensate stream and a non-condensable fluid stream. Produced fluids may be separated into three or more streams including at least a top stream, a bottom stream, and a middle stream. Produced fluids may be separated into four or more streams. Such streams may include at least a top stream, a bottoms stream, and at least two middle streams. One of the middle streams may be heavier than another middle stream.

Produced fluids may be separated into five or more streams. Such streams may include at least a top stream, a bottoms stream, a naphtha stream, a diesel stream, and a jet fuel stream. At least one of the streams may be separated into two or more substreams.

In some embodiments, the produced fluids may include pyrolyzation fluids, carbon dioxide, molecular hydrogen, and/or steam. A portion of the pyrolyzation fluids, carbon dioxide, molecular hydrogen, and/or steam

may be separated from the produced fluids. Pyrolyzation fluids, carbon dioxide, molecular hydrogen, and/or steam may be utilized in one or more treatment process of the produced fluids.

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 depicts 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 heater wells located in a hydrocarbon containing formation.

FIG. 4 depicts a schematic of a surface facility configuration that heats a fluid for use in an in situ treatment process and/or a surface facility configuration.

FIG. 5 depicts an embodiment for recovering heat from a heated formation and transferring the heat to an above-ground processing unit.

FIG. 6 depicts an embodiment for recovering heat from one formation and providing heat to another formation with an intermediate production step.

FIG. 7 depicts an embodiment for recovering heat from one formation and providing heat to another formation in situ.

FIG. 8 depicts an embodiment of a region of reaction within a heated formation.

FIG. 9 depicts an embodiment of a conduit placed within a heated formation.

FIG. 10 depicts an embodiment of a U-shaped conduit placed within a heated 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 OF THE INVENTION

The following description generally relates to systems and methods for treating a hydrocarbon containing formation (e.g., a formation containing coal (including lignite, sapropelic coal, etc.), oil shale, carbonaceous shale, shungites, kerogen, bitumen, oil, kerogen and oil in a low permeability matrix, heavy hydrocarbons, asphaltites, natural mineral waxes, formations wherein kerogen is blocking production of other hydrocarbons, etc.). 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.

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.

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. In addition, it is envisioned that in some embodiments heat provided to or generated in one or more heat sources may be supplied by other sources of energy. The other sources of energy may directly heat a formation, or the energy may be applied to a transfer media that directly or indirectly heats the formation. It is to be understood that one or more heat sources that are applying heat to a formation may use different sources of energy. For example, for a given formation some heat sources may supply heat from electric resistance heaters, some heat sources may provide heat from combustion, and some heat sources may provide heat from one or more other energy sources (e.g., chemical reactions, solar energy, wind energy, biomass, or other sources of renewable energy). A chemical reaction may include an exothermic reaction (e.g., an oxidation reaction). A heat source may include a heater that provides 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 that react with material in or produced from a formation (e.g., natural distributed combustors), 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.

"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.

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 pressure in a formation may be maintained during an in situ conversion process between about 2 bars absolute and

about 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. 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 substantially only one heat source.

In some embodiments, a plurality of heated portions may exist within a unit of heat sources. A unit of heat sources refers to a minimal number of heat sources that form a template that is repeated to create a pattern of heat sources within the formation. There will typically be many heated portions, as well as many parts of the formations within the pattern of heat sources. In some embodiments, a large spacing may provide for a relatively slow heating rate of hydrocarbon material. The slow heating rate may allow for pyrolysis of hydrocarbon material with minimal coking or no coking within the formation away from areas in the vicinity of the heat sources. Heating from heat sources allows the part of the formation to reach pyrolysis temperatures so that all hydrocarbons within the part of the formation may be subject to pyrolysis reactions. In some in situ conversion embodiments, a majority of pyrolysis fluids are produced when the part of the formation is within a range from about 0 m to about 25 m from a heat source.

In an in situ conversion process embodiment, a heating rate may be controlled to minimize costs associated with heating a part of the formation. The costs may include, for example, input energy costs and equipment costs. In certain embodiments, a cost associated with heating a part of the formation may be minimized by reducing a heating rate when the cost associated with heating is relatively high and increasing the heating rate when the cost associated with heating is relatively low. For example, a heating rate of about 330 watts/m may be used when the

associated cost is relatively high, and a heating rate of about 1640 watts/m may be used when the associated cost is relatively low. In an embodiment, the heating rate may be varied from a higher heating rate during low energy usage times, such as during the night, to a lower heating rate during high energy usage times, such as during the day.

5 As shown in FIG. 2, in addition to heat sources 100 one or more production wells 102 will typically be placed within the portion of the hydrocarbon containing formation. Formation fluids may be produced through production wells 102. In some embodiments, production well 102 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. 10 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 15 amount of heat applied to heat sources that heat the formation.

Because permeability and/or porosity increases in the heated formation, produced vapors may flow considerable distances through the formation with relatively little pressure differential. Increases in permeability may result from a reduction of mass of the heated portion due to vaporization of water, removal of hydrocarbons, and/or creation of fractures. Fluids may flow more easily through the heated portion. In some embodiments, 20 production wells may be provided in upper portions of hydrocarbon layers.

FIG. 3 illustrates an embodiment of hydrocarbon containing layer 104 that may be at a near-horizontal angle with respect to an upper surface of ground 106. An angle of hydrocarbon containing layer 104, however, may vary. For example, hydrocarbon containing layer 104 may dip or be steeply dipping. As shown in FIG. 3, production wells 102 may extend into a hydrocarbon containing formation near the top of heated portion 108 heated 25 by heater well 110. Extending production wells significantly into the depth of the heated hydrocarbon layer may be unnecessary.

Fluid generated within a hydrocarbon containing formation may move a considerable distance through the hydrocarbon containing formation as a vapor. The considerable distance may be over 1000 m depending on various factors (e.g., permeability of the formation, properties of the fluid, temperature of the formation, and pressure 30 gradient allowing movement of the fluid). Due to increased permeability in formations subjected to in situ conversion and formation fluid removal, production wells may only need to be provided in every other unit of heat sources or every third, fourth, fifth, or sixth units of heat sources.

During an in situ process, production wells may be operated such that the production wells are at a lower pressure than other portions of the formation. In some embodiments, a vacuum may be drawn at the production 35 wells. Maintaining the production wells at lower pressures may inhibit fluids in the formation from migrating outside of the in situ treatment area.

Certain embodiments may include controlling the heat provided to at least a portion of the formation such that production of less desirable products in the portion may be substantially inhibited. Controlling the heat provided to at least a portion of the formation may also increase the uniformity of permeability within the 40 formation. For example, controlling the heating of the formation to inhibit production of less desirable products

may, in some embodiments, include controlling the heating rate to less than a selected amount (e.g., 10 °C, 5 °C, 3 °C, 1 °C, 0.5 °C, or 0.1 °C) per day.

Since formations during heating will typically have temperature profiles throughout them, in the context of this patent “substantially uniform” heating means heating such that the temperatures in a majority of the section do not vary by more than 100 °C from the assessed average temperature in the majority of the part of the formation (volume) being treated.

Substantially uniform heating of the hydrocarbon containing formation may result in a substantially uniform increase in permeability. For example, uniformly heating may generate a series of substantially uniform fractures within the heated portion due to thermal stresses generated in the formation. Heating substantially uniformly may generate pyrolysis fluids from the portion in a substantially homogeneous manner. Water removed due to vaporization and production may result in increased permeability of the heated portion. In addition to creating fractures due to thermal stresses, fractures may also be generated due to fluid pressure increase. As fluids are generated within the heated portion a fluid pressure within the heated portion may also increase. As the fluid pressure approaches a lithostatic pressure of the heated portion, fractures may be generated. Substantially uniform heating and homogeneous generation of fluids may generate substantially uniform fractures within the heated portion. In some embodiments, a permeability of a heated section of a hydrocarbon containing formation may not vary by more than a factor of about 10.

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.

Certain embodiments for treating heavy hydrocarbons in a relatively low permeability formation may include providing heat from one or more heat sources to pyrolyze some of the heavy hydrocarbons and then to vaporize a portion of the heavy hydrocarbons. The heat sources may pyrolyze at least some heavy hydrocarbons in a part of the formation and may pressurize at least a portion of the part of the formation. During the heating, the pressure within the formation may increase substantially. The pressure in the formation may be controlled such that the pressure in the formation may be maintained to produce a fluid of a desired composition. Pyrolyzation fluid may be removed from the formation as vapor from one or more heater wells by using the back pressure created by heating the formation.

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.

Referring back to FIG. 2, heat sources 100 may be placed within at least a portion of the hydrocarbon containing formation. Heat sources 100 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 100 may also include other types of heaters. Heat sources 100 may provide heat to at least a portion of a hydrocarbon containing formation. Energy may be supplied to the heat sources 100 through supply lines 112. The supply lines may be structurally different depending on the type of heat source or heat sources being used to heat the formation. Supply lines 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 102 may be used to remove formation fluid from the formation. Formation fluid produced from production wells 102 may be transported through collection piping 114 to treatment facilities 116. Formation fluids may also be produced from heat sources 100. For example, fluid may be produced from heat sources 100 to control pressure within the formation adjacent to the heat sources. Fluid produced from heat sources 100 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. In some embodiments, barriers may be used to inhibit migration of fluids (e.g., generated fluids and/or groundwater) into and/or out of a portion of a formation undergoing an in situ conversion process. Barriers may include, but are not limited to naturally occurring portions (e.g., overburden and/or underburden), freeze wells, frozen barrier zones, low temperature barrier zones, grout walls, sulfur wells, dewatering wells, injection wells, a barrier formed by a gel produced in the formation, a barrier formed by precipitation of salts in the formation, a barrier formed by a polymerization reaction in the formation, sheets driven into the formation, or combinations thereof.

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.

Formation fluid produced from a hydrocarbon containing formation during treatment may include a mixture of different components (e.g., carbon dioxide, steam, hydrocarbon fluids, molecular hydrogen, etc.). In some in situ conversion process embodiments, formation fluid produced from the formation may include molecular hydrogen (H_2). Molecular hydrogen may be from about 0.1 volume % to about 80 volume % of a non-condensable component of formation fluid produced from the formation. In some in situ conversion process embodiments, molecular hydrogen may be about 5 volume % to about 70 volume % of the non-condensable component of formation fluid produced from the formation. The amount of hydrogen in the formation fluid may be strongly dependent on the temperature of the formation. A high formation temperature may result in the production of significant amounts of hydrogen. A high temperature may also result in the formation of a significant amount of coke within the formation.

To increase the economic value of products generated from the formation, formation fluid may be treated using a variety of treatment processes. Processes utilized to treat formation fluid may include distillation (e.g., atmospheric distillation, fractional distillation, and/or vacuum distillation), condensation (e.g., fractional), cracking (e.g., thermal cracking, catalytic cracking, fluid catalytic cracking, hydrocracking, residual hydrocracking, and/or steam cracking), reforming (e.g., thermal reforming, catalytic reforming, and/or hydrogen steam reforming), hydrogenation, coking, solvent extraction, solvent dewaxing, polymerization (e.g., catalytic polymerization and/or catalytic isomerization), visbreaking, alkylation, isomerization, deasphalting, hydrodesulfurization, catalytic dewaxing, desalting, extraction (e.g., of phenols, other aromatic compounds, etc.), and/or stripping.

Formation fluids may undergo treatment processes in a first in situ treatment area as the formation fluid is generated and produced, in a second in situ treatment area where a specific treatment process occurs, and/or in surface treatment units. A "surface treatment unit" is a unit used to treat at least a portion of formation fluid at the surface. Surface treatment units may include, but are not limited to, reactors (e.g., hydrotreating units, cracking units, ammonia generating units, fertilizer generating units, and/or oxidizing units), separating units (e.g., recovery units, air separating units, liquid-liquid extraction units, adsorption units, absorbers, ammonia recovery and/or generating units, vapor/liquid separating units, distillation columns, reactive distillation columns, and/or condensing units), reboiling units, heat exchangers, pumps, pipes, storage units, and/or energy producing units (e.g., fuel cells and/or gas turbines). Multiple surface treatment units used in series, in parallel, and/or in a combination of series and parallel are referred to as a surface facility configuration. Surface facility configurations may vary dramatically due to a composition of formation fluid as well as the products being generated.

Surface treatment configurations may be combined with treatment processes in various surface treatment systems to generate a multitude of products. Products generated at a site may vary with local and/or global market conditions, formation characteristics, proximity of formation to a purchaser, and/or available feedstocks. Generated products may be utilized on site, transferred to another site for use, and/or sold to a purchaser.

Feedstocks for surface treatment units may be generated in treatment areas and/or surface treatment units. A "feedstock" is a stream containing at least one component required for a treatment process. Feedstocks may include, but are not limited to, formation fluid, synthetic condensate, a gas stream, a water stream, a gas fraction, a light fraction, a middle fraction, a heavy fraction, bottoms, a naphtha fraction, a jet fuel fraction, a diesel fraction, and/or a fraction containing a specific component (e.g., heart fraction, phenols containing fraction, etc.). In some embodiments, feedstocks are hydrotreated prior to entering a surface treatment unit. For example, a hydrotreating unit used to hydrotreat a synthetic condensate may generate hydrogen sulfide to be utilized in the synthesis of a fertilizer such as ammonium sulfate. Alternatively, one or more components (e.g., heavy metals) may have been removed from formation fluids prior to entering the surface treatment unit.

In alternate embodiments, feedstocks for in situ treatment processes may be generated at the surface in surface treatment units. For example, a hydrogen stream may be separated from formation fluid in a surface treatment unit and then provided to an in situ treatment area to enhance generation of upgraded products. In addition, a feedstock may be injected into a treatment area to be stored for later use. Alternatively, storage of a feedstock may occur in storage units on the surface.

The composition of products generated may be altered by controlling conditions within a treatment area and/or within one or more surface treatment units. Conditions within the treatment area and/or one or more surface treatment units which affect product composition include, but are not limited to, average temperature, fluid pressure, partial pressure of H_2 , temperature gradients, composition of formation material, heating rates, and

composition of fluids entering the treatment area and/or the surface treatment unit. Many different surface facility configurations exist for the synthesis and/or separation of specific components from formation fluid.

Controlling formation conditions to control the pressure of hydrogen in the produced fluid may result in improved qualities of the produced fluids. In some embodiments, it may be desirable to control formation conditions so that the partial pressure of hydrogen in a produced fluid is greater than about 0.5 bars absolute, as measured at a production well.

In one embodiment, a method of treating a hydrocarbon containing formation in situ may include adding hydrogen to the part of the formation after a temperature of the part of the formation is at least about 270 °C. Other embodiments may include controlling a temperature of the formation by selectively adding hydrogen to the formation.

In an embodiment, a portion of a hydrocarbon containing formation may be heated to increase a partial pressure of H₂. In some embodiments, an increased H₂ partial pressure may include H₂ partial pressures in a range from about 0.5 bars to about 7 bars. Alternatively, an increased H₂ partial pressure range may include H₂ partial pressures in a range from about 5 bars to about 7 bars. For example, a majority of hydrocarbon fluids may be produced wherein a H₂ partial pressure is within a range of about 5 bars to about 7 bars. A range of H₂ partial pressures within the pyrolysis H₂ partial pressure range may vary depending on, for example, temperature and pressure of the heated portion of the formation.

The average temperature of the formation may be controlled by selectively adding hydrogen to the part of the formation. Hydrogen added to the formation may react in exothermic reactions. The exothermic reactions may heat the formation and reduce the amount of energy that needs to be supplied from heat sources to the formation. In some embodiments, an amount of hydrogen may be added to the part of the formation such that an average temperature of the formation does not exceed about 400 °C.

A valve may maintain, alter, and/or control a pressure within a heated portion of a hydrocarbon containing formation. For example, a heat source disposed within a hydrocarbon containing formation may be coupled to a valve. The valve may release fluid from the formation through the heat source. In addition, a pressure valve may be coupled to a production well within the hydrocarbon containing formation. In some embodiments, fluids released by the valves may be collected and transported to a surface unit for further processing and/or treatment.

An in situ conversion process for hydrocarbons may include providing heat to a portion of a hydrocarbon containing formation and controlling a temperature, rate of temperature increase, and/or pressure within the heated portion. A temperature and/or a rate of temperature increase of the heated portion may be controlled by altering the energy supplied to heat sources in the formation.

Hydrocarbons to be subjected to in situ conversion may be located under a large area. The in situ conversion system may be used to treat small portions of the formation, and other sections of the formation may be treated as time progresses. In an embodiment of a system for treating a formation (e.g., an oil shale formation), a field layout for 24 years of development may be divided into 24 individual plots that represent individual drilling years. Each plot may include 120 "tiles" (repeating matrix patterns) wherein each plot is made of 6 rows by 20 columns of tiles. Each tile may include 1 production well and 12 or 18 heater wells. The heater wells may be placed in an equilateral triangle pattern with a well spacing of about 12 m. Production wells may be located in centers of equilateral triangles of heater wells, or the production wells may be located approximately at a midpoint between two adjacent heater wells.

Exact placement of heater wells, production wells, etc. will depend on variables specific to the formation (e.g., thickness of the layer or composition of the layer), project economics, etc. In certain embodiments, heater wells may be substantially horizontal while production wells may be vertical, or vice versa. In some embodiments, wells may be aligned along dip or strike or oriented at an angle between dip and strike.

5 The spacing between heat sources may vary depending on a number of factors. The factors may include, but are not limited to, the type of a hydrocarbon containing formation, the selected heating rate, and/or the selected average temperature to be obtained within the heated portion. In some well pattern embodiments, the spacing between heat sources may be within a range of about 5 m to about 25 m. In some well pattern embodiments, spacing between heat sources may be within a range of about 8 m to about 15 m.

10 In an embodiment, a heater within an open wellbore may generate heat. Generated heat may radiatively heat a portion of a hydrocarbon containing formation adjacent to the heater. To a lesser extent, gas conduction adjacent to the heater may heat the portion of the formation. Using an open wellbore completion may reduce casing and packing costs associated with filling the opening with a material to provide conductive heat transfer between the heater and the formation. In addition, heat transfer by radiation may be more efficient than heat transfer by
15 conduction in a formation, so the heaters may be operated at lower temperatures using radiative heat transfer. Operating at a lower temperature may extend the life of the heat source and/or reduce the cost of material needed to form the heat source.

In certain embodiments, one or more conduits may be provided to supply additional components (e.g., nitrogen, carbon dioxide, reducing agents such as gas containing hydrogen, etc.) to formation openings, to bleed off
20 fluids, and/or to control pressure. Formation pressures tend to be highest near heating sources. Providing pressure control equipment in heat sources may be beneficial. In some embodiments, adding a reducing agent proximate the heating source assists in providing a more favorable pyrolysis environment (e.g., a higher hydrogen partial pressure). Since permeability and porosity tend to increase more quickly proximate the heating source, it is often optimal to add a reducing agent proximate the heating source so that the reducing agent can more easily move into
25 the formation.

During an in situ conversion process of a hydrocarbon containing formation formation fluid may exit the formation at a temperature in excess of about 300 °C. Utilizing thermal energy within the formation fluid may reduce an amount of energy required by the treatment system. In certain embodiments, formation fluid produced at an elevated temperature may be provided to one or more surface treatment units. Formation fluid may enter the
30 surface treatment unit at a temperature greater than about 200 °C, 250 °C, 275 °C, 300 °C, 325 °C, or 350 °C. Alternatively, thermal energy from formation fluid may be transferred to other fluids utilized by the surface facility configuration and/or the in situ treatment process.

As shown in FIG. 4, formation fluid 130 produced from wellhead 132 may flow to heat exchange unit 134. Heat exchange fluid 136 may flow into heat exchange unit 134. Thermal energy from formation fluid 130 may be
35 transferred to heat exchange fluid 136 in heat exchange unit 134 to generate heated fluid 138 and cooled formation fluid 140. Heat exchange fluid 136 may include any fluid stream produced from a formation (e.g., formation fluid, pyrolysis fluid, water, and/or synthesis gas), and/or any fluid stream generated and/or separated out within a surface treatment unit (e.g., water stream, light fraction, middle fraction, heavy fraction, hydrotreated liquid hydrocarbon condensate stream, jet fuel stream, etc.).

40 In some in situ conversion process embodiments, a heat exchange unit may be used to increase a temperature of the formation fluid and decrease a temperature of the heat exchange fluid to generate a cooled fluid

and a heated formation fluid. For example, pyrolysis fluids may be produced from a first treatment area at a temperature of about 300 °C. Synthesis gas may be produced from a second treatment area at a temperature of about 600 °C. The pyrolysis fluids and synthesis gas may flow in separate conduits to distant surface treatment units. Heat loss may cause the pyrolysis fluids to condense before reaching a distant surface treatment unit for treatment. Various configurations of conduits, known in the art, may be used to form a heat exchange unit to transfer thermal energy from the synthesis gas to the pyrolysis fluids to decrease, or prevent, condensation of the pyrolysis fluids.

Once a formation has undergone an in situ conversion process, heat from the process may remain within the formation. Heat may be recovered from the formation using a heat transfer fluid. Heat transfer fluids used to recover energy from a hydrocarbon containing formation may include, but are not limited to, formation fluids, product streams (e.g., a hydrocarbon stream produced from crude oil introduced into the formation), inert gases, hydrocarbons, liquid water, and/or steam. FIG. 5 illustrates an embodiment for recovering heat remaining in formation 142 by providing a product stream through injection well 144. Heat remaining in the formation may transfer to the product stream. The formation heat may be controlled with heat source 100. The heated product stream may be produced from the formation through production well 102. The heat of the product stream may be transferred to any number of surface treatment units 116 or to other formations.

In an in situ conversion process embodiment, heat recovered from the formation by a heat transfer fluid may be directed to surface treatment units to utilize the heat. For example, a heat transfer fluid may flow to a steam-cracking unit. The heat transfer fluid may pass through a heat exchange mechanism of the steam-cracking unit to transfer heat from the heat transfer fluid to the steam-cracking unit. The transferred heat may be used to vaporize water or as a source of heat for the steam-cracking unit.

In some in situ conversion process embodiments, heat transfer fluid may be used to transfer heat to a hydrotreating unit. The heat transfer fluid may pass through a heat exchange mechanism of the hydrotreating unit. Heat from the product stream may be transferred from the heat transfer fluid to the hydrotreating unit.

Alternatively, a temperature of the heat transfer fluid may be increased with a heating unit prior to processing the heat transfer fluid in a steam cracking unit or hydrotreating unit. In addition, heat of a heat transfer fluid may be transferred to any other type of unit (e.g., distillation column, separator, regeneration unit for an activated carbon bed, etc.).

Heat from a heated formation may be recovered for use in heating another formation. FIG. 6 illustrates an embodiment of a heat transfer fluid provided through injection well 144 into heated formation 146. Heat may transfer from the heated formation to the heat transfer fluid. Heat source 100 may be used to control formation heat. The heat transfer fluid may be produced from production well 102. The heat transfer fluid may be directed through injection well 144' to transfer heat from the heat transfer fluid to formation 142. Formation conditions subsequent to an in situ conversion process may determine the heat transfer fluid temperature. The heat transfer fluid may be produced from production well 102'. In some embodiments, formation 142 may include U-tube wells or closed casings with fluid insertion ports and fluid removal ports so that heat transfer fluid does not enter into the rock of the formation.

Movement of the heat transfer fluid (e.g., product streams, inert gas, steam, and/or hydrocarbons) through the formation may be controlled such that any associated hydrocarbons in the formation are directed towards the production wells. The formation heat and mass transfer of the heat transfer fluid may be controlled such that fluids within the formation are swept towards the production wells. During remediation of a formation, the formation heat

and mass transfer of the heat transfer fluid may be controlled such that transfer of heat from the formation to the heat transfer fluid is accomplished simultaneously with clean up of the formation.

FIG. 7 illustrates an in situ conversion process embodiment in which a heat transfer fluid is provided to formation 142 through injection well 144. Heat within formation 142 may be controlled by heat source 100. The heat of the heat transfer fluid may be transferred to cooler formation 148. The heat transfer fluid may be produced through production well 102. In other embodiments, a heat transfer fluid may be directed to a plurality of formations to heat the plurality of formations.

FIG. 8 illustrates an embodiment for controlling formation 142 to produce region of reaction 150 in the formation. A region of reaction may be any section of the formation having a temperature sufficient for a reaction to occur. A region of reaction may be hotter or cooler than a portion of a formation proximate the region of reaction. Material may be directed to the region of reaction through injection well 144. The material may be reacted within the region of reaction. Any number and any type of heat source 100 may heat the formation and the region of reaction. Appropriate heat sources include, but are not limited to, electric heaters, surface burners, flameless distributed combustors, and/or natural distributed combustors. The product may be produced through production well 102.

In some in situ conversion process embodiments, a region of reaction may be heated by transference of heat from a heated product to the region of reaction. In some embodiments, regions of reaction may be in series. A material may flow through the regions of reaction in a serial manner. The regions of reaction may have substantially the same properties. As such, flowing a material through such regions of reaction may increase a residence time of the material in the regions of reaction. Alternatively, the regions of reaction may have different properties (e.g., temperature, pressure, and hydrogen content). Flowing a material through such regions of reaction may include performing several different reactions with the material. Various materials may be reacted in a region of reaction. Examples of such materials include, but are not limited to, materials produced by an in situ conversion process and hydrocarbons produced from petroleum crude (e.g., tar, pitch, asphaltenes, heavy hydrocarbons, naphtha, methane, ethane, propane, and/or butane).

In some in situ conversion process embodiments, a region of reaction may be formed by placing conduit 152 in a heated portion of formation 146. FIG. 9 depicts such an embodiment of an in situ conversion process. A portion of conduit 152 may be heated by the formation to form a region of reaction within the conduit. The conduit may inhibit contact between the material and the formation. The formation temperature and conduit temperature may be controlled by heat source 100. Material may be provided through injection well 144. The material may be produced through production well 102.

A shape of a conduit may be variable. For example, the conduit may be curved, straight, or U-shaped (as shown in FIG. 10) U-shaped conduit 154 may be placed within a heater well in a heated formation. Any number of materials may be reacted within the conduit. For example, water may be passed through a conduit such that the water is heated to a temperature higher than the initial water temperature. In other embodiments, water may be heated in a conduit to produce steam. Material may be provided through injection site 156 and produced through production site 158. The formation temperature may be controlled by heat source 100.

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.

5

WHAT IS CLAIMED:

1. A method of treating a hydrocarbon containing formation in situ, comprising:
providing heat from one or more heaters to at least a portion of the formation;
5 allowing the heat to transfer from one or more heaters to a part of the formation; and
producing fluids from the part of the formation wherein at least a portion of the produced fluids have been
heated by the heat provided by one or more of the heaters, and wherein at least a portion of the produced fluids are
produced from a wellhead at a temperature greater than about 200 °C.
- 10 2. The method of claim 1, wherein at least a portion of the produced fluids are produced from a wellhead at a
temperature greater than about 250 °C or 300 °C
3. The method according to claim 1 or 2 further comprising removing heat from the produced fluids in a heat
exchanger.
- 15 4. The method according to claims 1 to 3, further comprising varying the heat provided to one or more of the
heaters to vary heat in at least a portion of the produced fluids.
5. The method according to one or more of claims 1 to 4, wherein the heat provided from at least one heater
20 is transferred to the formation substantially by conduction.
6. The method according to one or more of claims 1 to 5, wherein the produced fluids are produced from a
well comprising at least one of the heaters.
- 25 7. The method according to one or more of claims 1 to 6, wherein the fluids are produced from the formation
when a partial pressure of hydrogen in at least a portion of the formation is at least about 0.5 bars.
8. The method according to one or more of claims 1 to 7 further comprising controlling a pressure within at
least a majority of the part of the formation, wherein the pressure is greater than about 2.0 bar absolute.
- 30 9. The method according to one or more of claims 1 to 8, further comprising providing at least a portion of
the produced fluids to a hydrotreating unit, a steam cracking unit, an olefin generating unit, a separating unit and/or
distillation unit.
- 35 10. The method according to one or more of claims 1 to 9, further comprising using heat in the produced fluids
to provide heat to a hydrotreating unit, an olefin generating unit and/or separating unit.
11. The method according to one or more claims of 1 to 10, further comprising varying the heat provided to
one or more of the heaters to vary heat in at least a portion of the produced fluids provided to a hydrotreating unit,
40 an olefin generating unit, and/or a separating unit.

12. The method according to one or more of claims 1 to 11 further comprising using at least about 50% of heat in the produced fluids to provide heat to a hydrotreating unit, an olefin generating unit and/or separating unit.

13. The method according to one or more of claims 1 to 12, wherein at least a portion of the produced fluids are provided to a hydrotreating unit, an olefin generating unit and/or a separating unit via a heated conduit.

14. The method according to one or more of claims 1 to 13, wherein at least a portion of the produced fluids are provided to a hydrotreating unit, olefin generating unit and/or separating unit via an insulated conduit; wherein the insulated conduit is insulated to inhibit heat loss from the produced fluids.

15. The method according to one or more of claims 1 to 14, wherein the produced fluids are produced at a wellhead, and wherein at least a portion of the produced fluids are provided to a hydrotreating unit, an olefin generating unit and/or a separating unit at a temperature that is within about 50 °C of the temperature of the produced fluids at the wellhead.

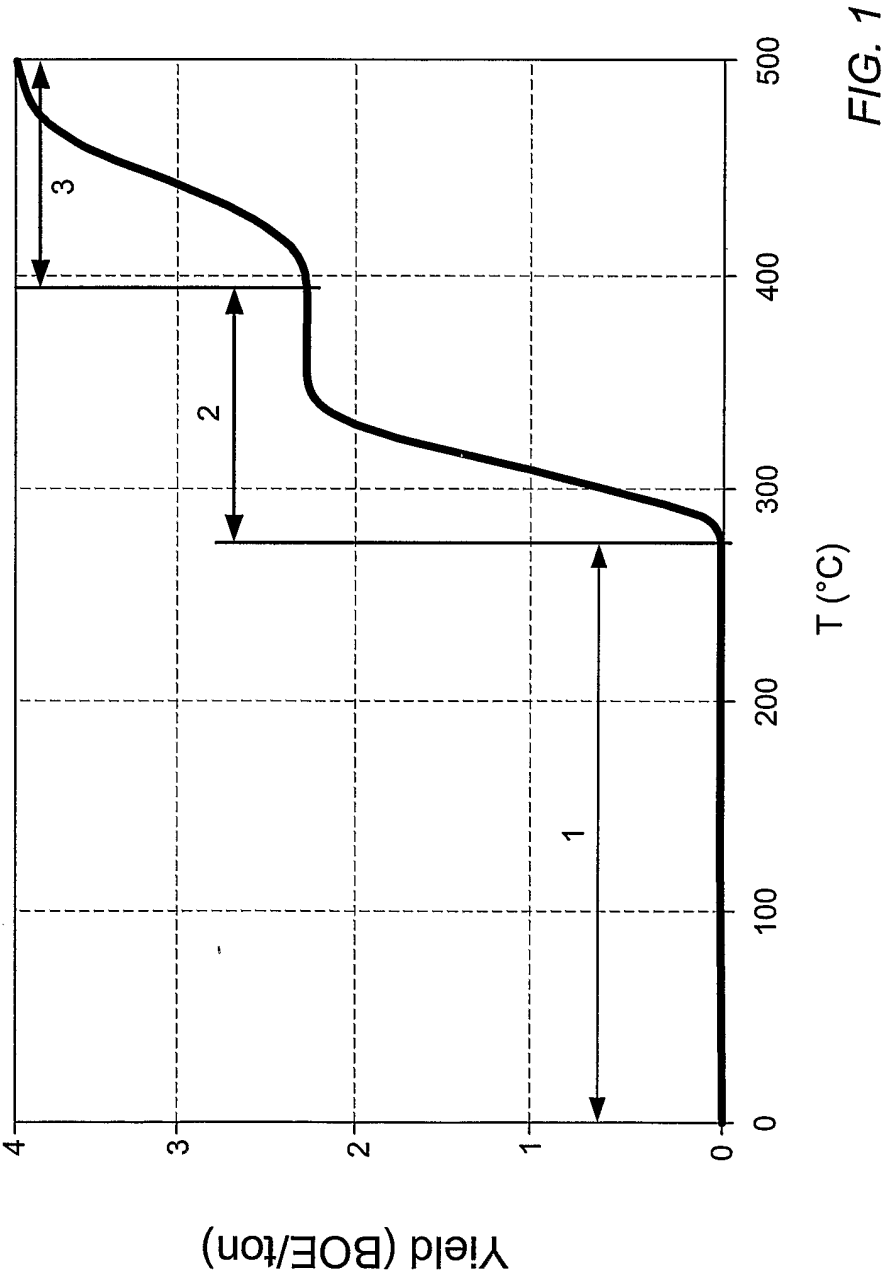
16. The method according to one or more of claims 9 to 15, further comprising hydrotreating at least a portion of the produced fluids such that the volume of hydrotreated produced fluids is about 4% greater than a volume of the produced fluids.

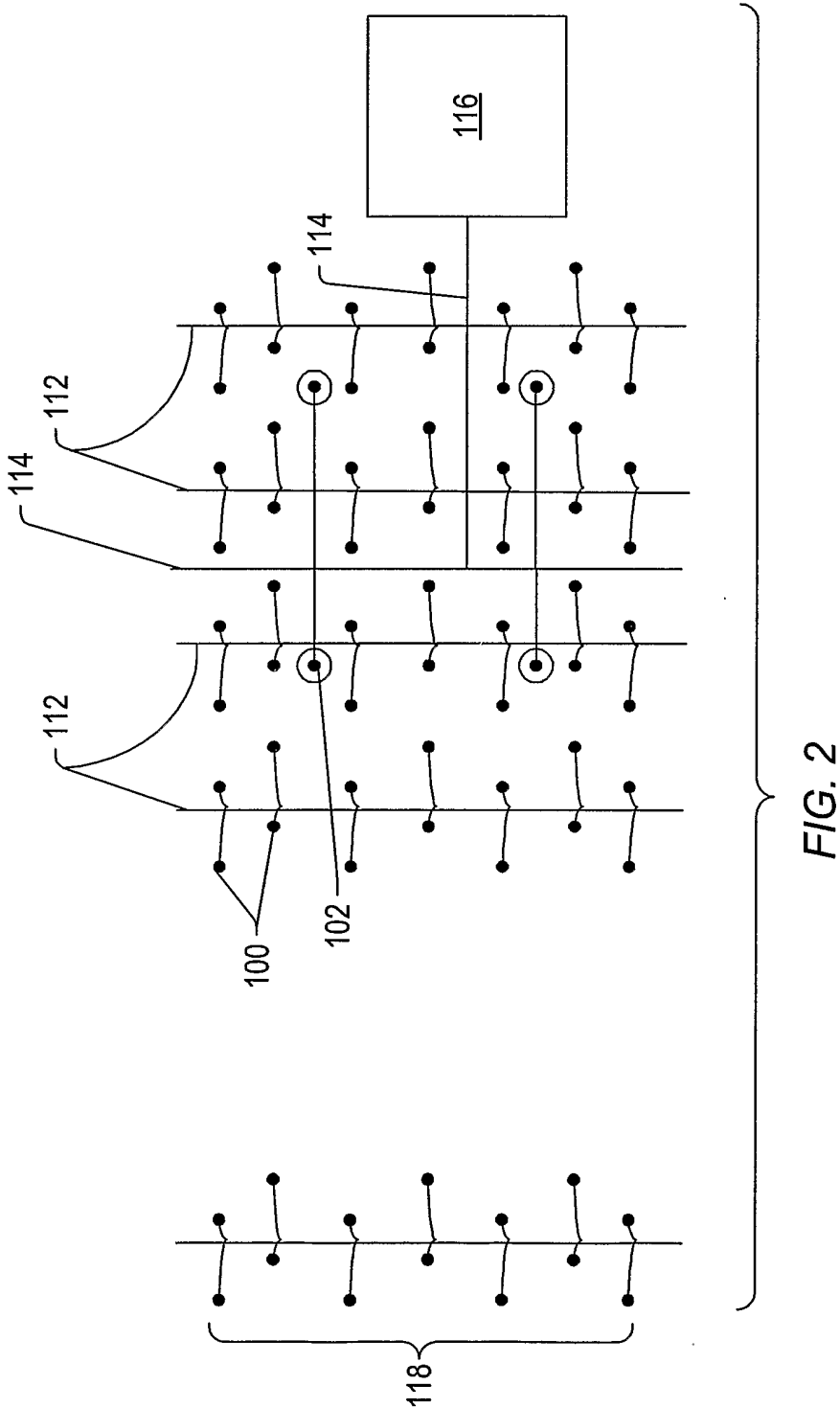
17. The method according to one or more of claims 9 to 16, wherein the produced fluids comprise molecular hydrogen, and using the molecular hydrogen in the produced fluids to hydrotreat at least a portion of the produced fluids.

18. The method according to one or more of claims 9 to 17, wherein the produced fluids comprise molecular hydrogen, hydrotreating at least a portion of the produced fluids, and wherein at least 50% of molecular hydrogen used for hydrotreating is provided by the molecular hydrogen in the produced fluids.

19. The method according to one or more of claims 1 to 18, wherein providing at least a portion of the produced fluids to the separating unit, and wherein the produced fluids comprise molecular hydrogen, and further comprising separating at least a portion of the molecular hydrogen from the produced fluids, and providing at least a portion of the separated molecular hydrogen to a surface treatment unit.

20. The method according to one or more of claims 1 to 19, wherein the produced fluids comprise molecular hydrogen, and further comprising separating at least a portion of the molecular hydrogen from the produced fluids, and providing at least a portion of the separated molecular hydrogen to an in situ treatment area.





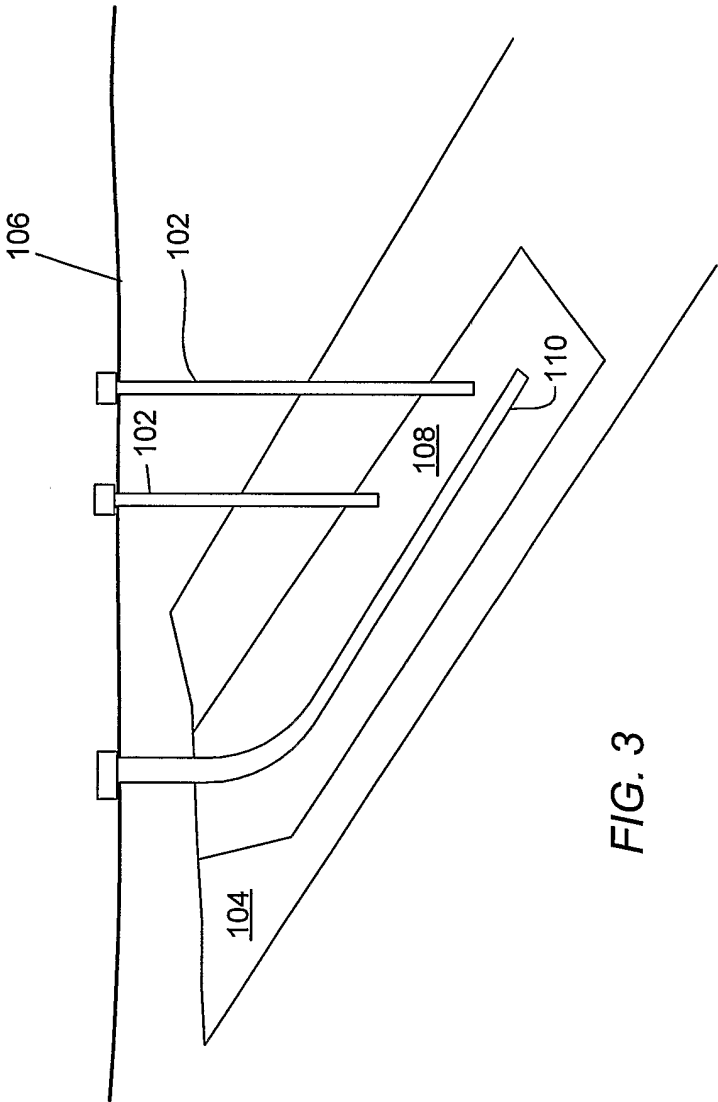


FIG. 3

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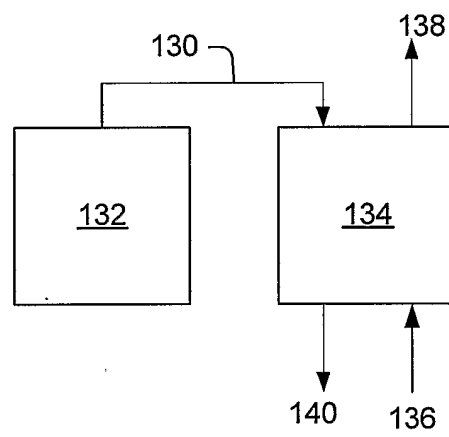
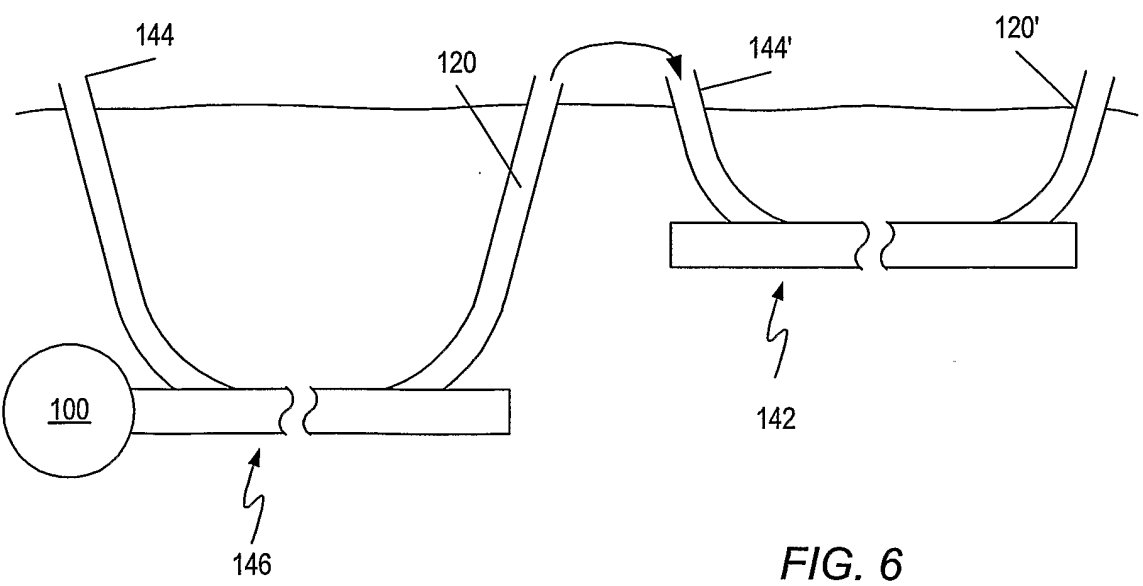
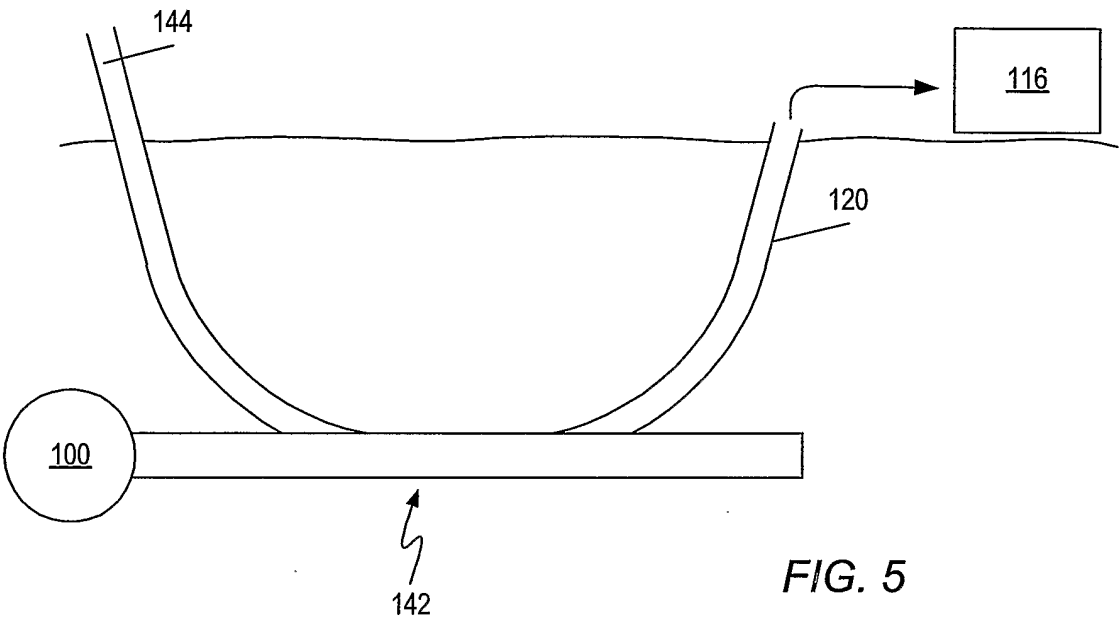
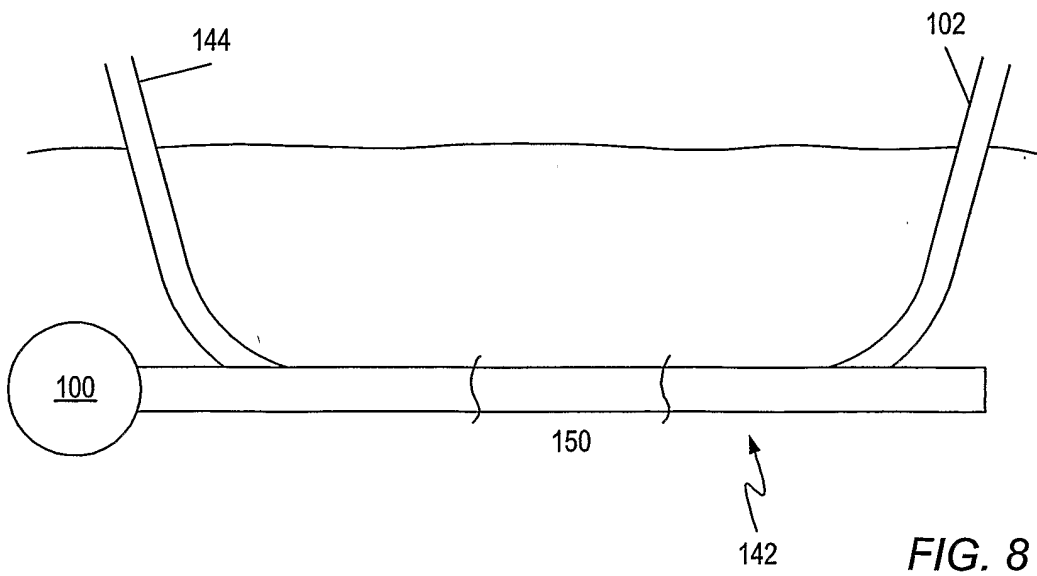
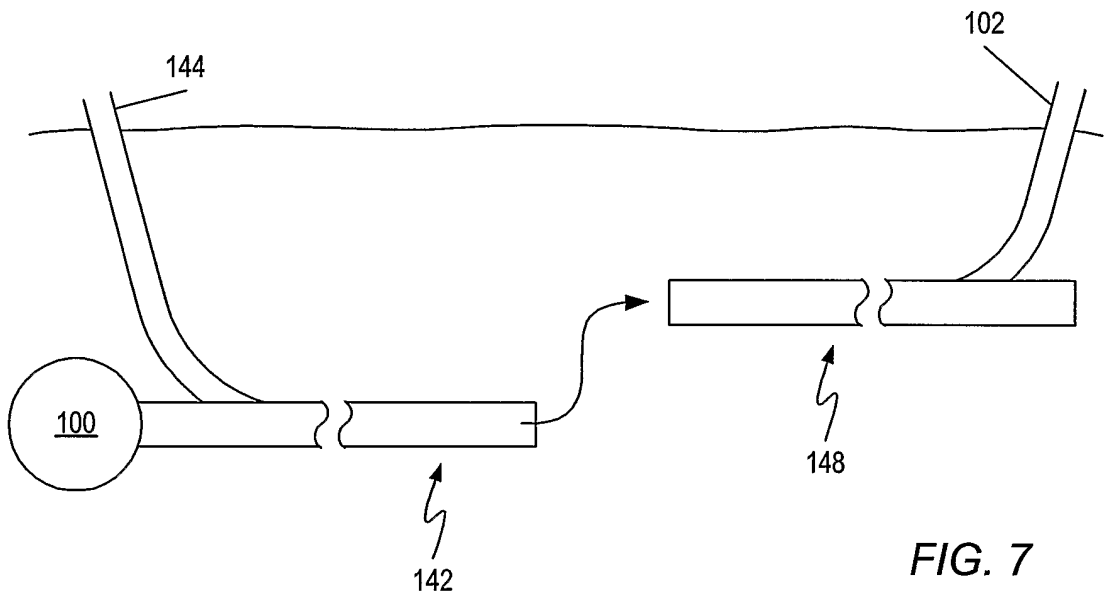


FIG. 4





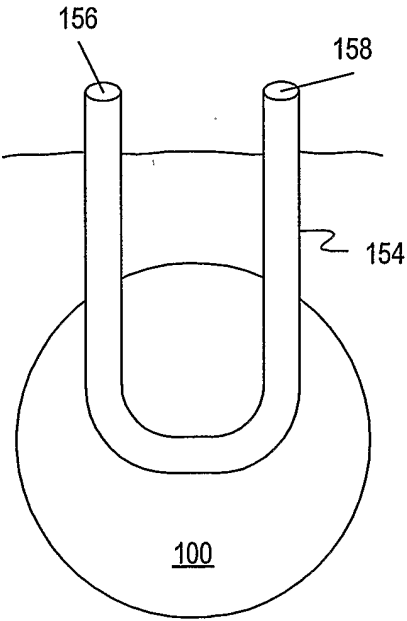
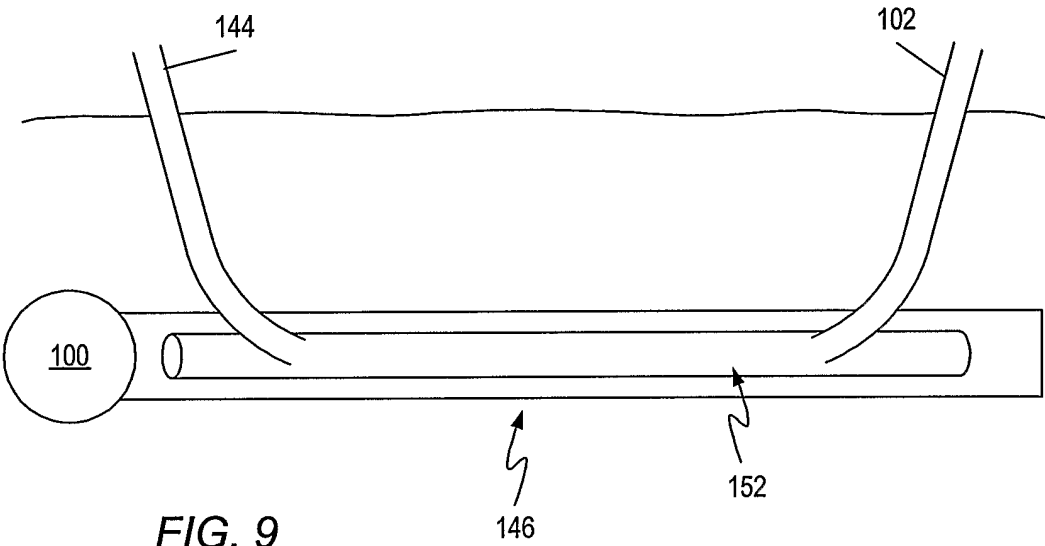


FIG. 10