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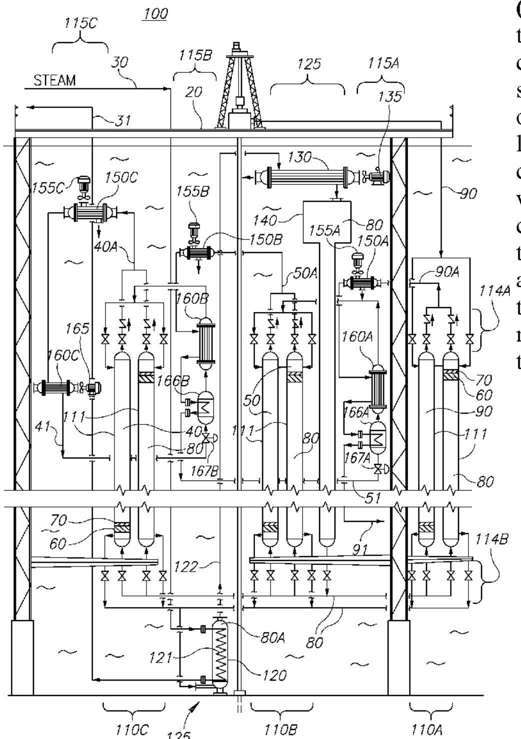

Figure 4

(57) Abstract: Underwater gas pressurization units and liquefaction systems, as well as pressurization and liquefaction methods are provided. Gas is compressed hydraulically in vessels that are used to reach a high compression ratio that lowers the liquefaction temperature. The pressurizing liquid or seawater is delivered gravitationally, after gasification, transport to smaller water depths and condensation. Cooling units are used to liquefy the compressed gas. A cascade of compression and cooling units may be used with sequentially higher liquefaction temperatures, which allow eventual cooling by sea water. Additionally, methods, systems and units for liquefaction of combustible material are provided. Aqueous salt solution having separates combustible material from waste rock and after heating and grinding the separated combustible material yields a paste of purified combustible material, which is fluidizing and hydrogenated underground in a hydrogenation chamber.

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UNDERWATER GAS LIQUEFACTION, GAS FIELD DEVELOPMENT AND PROCESSING COMBUSTIBLE MATERIALS

BACKGROUND OF THE INVENTION

1. TECHNICAL FIELD

[0001] The present invention relates to the field of energy production and processing, and more particularly, to liquefaction of natural gas and other fossil fuels.

2. DISCUSSION OF RELATED ART

[0002] Natural gas liquefaction poses significant challenges regarding its energy consumption and delivery of the natural gas to the liquefaction plant. Existing technologies use energy very extensively and require long pipework to deliver natural gas that is produced from sea sources.

[0003] Coal liquefaction is used to process coal and in particular to produce liquid fuel from coal (see e.g., the hundred years' old Bergius process). However, major difficulties in such processes involve the need to produce, process and transport huge amounts of fossil fuel for liquefaction, as well as the high energy demand of the process, environmental hazards posed by the liquefaction and by chemicals that are used in the process, as well as low processing efficiency in some cases.

SUMMARY OF THE INVENTION

[0004] One aspect of the present invention provides an underwater gas pressurization unit comprising: at least one vertical vessel arranged to receive gas through a top of the vessel and a pressurizing liquid through a bottom of the vertical vessel, and further comprising a layer of water-immiscible liquid upon a layer of aqueous salt solution, wherein a density of the pressurizing liquid is higher than a density of aqueous salt solution, which is in turn higher than a density of the water-immiscible liquid, to maintain the layer of aqueous salt solution on top of the pressurizing liquid and to maintain the layer of water-immiscible liquid on top of the layer of aqueous salt solution, and a valve system arranged to pressurize the gas by introducing the pressurizing liquid into the vessel, evacuate the pressurized gas through the top of the vertical vessel upon reaching a specified pressure and introduce gas into the vessel by evacuating the pressurizing liquid through the bottom of the vertical vessel.

[0005] Another aspect of the present invention provides an underwater natural gas liquefaction system comprising at least two underwater gas pressurization units, one arranged to compress natural gas and another arranged to compress a coolant that is used to cool the compressed natural gas.

[0001] One aspect of the present invention provides an underwater gas pressurization unit comprising: at least one vessel arranged to receive gas through a top of the vessel and seawater through a bottom of the vessel, and further comprising a layer of water-immiscible liquid separating between the gas and the seawater, the water-immiscible liquid selected to have a density which is intermediate between a density of the gas and a density of the seawater; and a valve system arranged to pressurize the gas by introducing the seawater into the vessel, evacuate the pressurized gas through the top of the vessel upon reaching a specified pressure and introduce gas into the vessel by evacuating the seawater through the bottom of the vessel. Evacuated seawater may be controllably introduced into production wells to enhance gas production.

[0002] One aspect of the present invention provides a method of separating and hydrogenating combustible material, the method comprising: separating the combustible material from waste rock gravitationally in an aqueous salt solution selected to have a density which is intermediate between a density of the combustible material and a density of the waste rock; heating and grinding the separated combustible material to yield a paste of purified combustible material; fluidizing the paste; and hydrogenating the fluidized paste in association with a Segner turbine.

[0003] One aspect of the present invention provides a hydrogenation unit comprising: a vertical shaft arranged to receive a fluid combustible material and maintain a downwards flow thereof; a Segner turbine in fluid communication with the vertical shaft and arranged to be rotated by the flowing fluid combustible material; a hydrogenation chamber enclosing a bottom portion of the vertical shaft and the Segner turbine, the hydrogenation chamber comprising a heating unit arranged to heat the fluid combustible material and a hydrogen supply arranged to introduce hydrogen into the fluid combustible material that exits the Segner turbine, to yield a hydrogenated combustible fluid; and a vertical enclosure in fluid communication with the hydrogenation chamber and arranged to maintain an upwards flow of the hydrogenated combustible fluid from the hydrogenation chamber while enabling recuperative heat exchange between the rising hydrogenated combustible fluid and the downwards flow of fluid combustible material.

[0006] These, additional, and/or other aspects and/or advantages of the present invention are set forth in the detailed description which follows; possibly inferable from the detailed description; and/or learnable by practice of the present invention.

BRIEF DESCRIPTION OF THE DRAWINGS

[0007] For a better understanding of embodiments of the invention and to show how the same may be carried into effect, reference will now be made, purely by way of example, to the accompanying drawings in which like numerals designate corresponding elements or sections throughout.

[0008] In the accompanying drawings:

[0009] **Figure 1** is a high level schematic block diagram of an underwater gas pressurization unit, according to some embodiments of the invention.

[0010] **Figure 2** is a high level schematic illustration of an underwater gas pressurization unit, according to some embodiments of the invention.

[0011] **Figure 3** is a high level schematic block diagram of an underwater natural gas liquefaction system, according to some embodiments of the invention.

[0012] **Figure 4** is a high level schematic illustration of an underwater natural gas liquefaction system, according to some embodiments of the invention.

[0013] **Figure 5** is a high level schematic flowchart illustrating a gas compression and liquefaction method, according to some embodiments of the invention.

[0004] **Figure 6** is a high level schematic block diagram of an underwater gas pressurization unit, according to some embodiments of the invention.

[0005] **Figure 7** is a high level schematic block diagram of an underwater natural gas liquefaction system, according to some embodiments of the invention.

[0006] **Figure 8** is a high level schematic illustration of underwater natural gas liquefaction system, according to some embodiments of the invention.

[0007] **Figure 9** is a high level schematic flowchart illustrating a gas compression and liquefaction method, according to some embodiments of the invention.

[0014] **Figure 10A** is a schematic illustration of a non-limiting example for a combustible material processing system, according to some embodiments of the invention.

[0015] **Figure 10B** is a high level schematic illustration of subsystem s in the combustible material processing system, according to some embodiments of the invention.

[0016] **Figure 11A** is a high level schematic flowchart illustrating central stages of a method of separating and hydrogenating combustible material, according to some embodiments of the invention.

[0017] **Figure 11B** is a high level schematic flowchart illustrating further stages of the method of separating and hydrogenating combustible material, according to some embodiments of the invention.

DETAILED DESCRIPTION OF THE INVENTION

[0018] Prior to the detailed description being set forth, it may be helpful to set forth definitions of certain terms that will be used hereinafter.

[0019] The term “combustible material” as used in this application refers to the any kind of material used to generate energy, especially sedimentary rocks such as coal, oil shale and other types of fossil fuels.

[0020] With specific reference now to the drawings in detail, it is stressed that the particulars shown are by way of example and for purposes of illustrative discussion of the preferred embodiments of the present invention only, and are presented in the cause of providing what is believed to be the most useful and readily understood description of the principles and conceptual aspects of the invention. In this regard, no attempt is made to show structural details of the invention in more detail than is necessary for a fundamental understanding of the invention, the description taken with the drawings making apparent to those skilled in the art how the several forms of the invention may be embodied in practice.

[0021] Before at least one embodiment of the invention is explained in detail, it is to be understood that the invention is not limited in its application to the details of construction and the arrangement of the components set forth in the following description or illustrated in the drawings. The invention is applicable to other embodiments or of being practiced or carried out in various ways. Also, it is to be understood that the phraseology and terminology employed herein is for the purpose of description and should not be regarded as limiting.

[0022] In certain embodiments, underwater gas pressurization units and liquefaction systems, as well as pressurization and liquefaction methods are provided herein. Gas is compressed hydraulically by a rising pressurization liquid that is separated from the gas by a water immiscible liquid layer on top of a aqueous salt solution. Tall vessels are used to reach a high compression ratio that lowers the liquefaction temperature. The pressurizing liquid is delivered gravitationally, after gasification, transport to smaller water depths and condensation. Cooling units are used to liquefy the compressed gas. A cascade of compression and cooling units may be used with sequentially higher liquefaction temperatures, which allow eventual cooling by sea water. The pressurizing liquid, dimensions of the vessels, the delivery unit, the coolants and the implementation of the cooling units are selected according to the sea location, to enable natural gas liquefaction in proximity to the gas source.

[0023] **Figure 1** is a high level schematic block diagram of an underwater gas pressurization unit **110**, according to some embodiments of the invention. **Figure 2** is a high level schematic illustration of underwater gas pressurization unit **110**, according to some embodiments of the invention. The thermodynamical processes used in the invention are shown schematically in **Figure 1** as pressurization **111** beyond the critical point and cooling the pressurized gas to liquefy **115** it.

[0024] Underwater gas pressurization unit **110** comprises at least one vertical vessel **111**, illustrated in **Figure 1** in two operation states, denoted **111A** for gas pressurization and **111B** for gas suction, as explained below. Vertical vessel **111** is arranged to receive gas **90** through a top **112** of the vertical vessel, e.g., through a top opening, and a pressurizing liquid **80** through a bottom **113** of the vertical vessel, e.g., through a bottom opening.

[0025] Underwater gas pressurization unit **110** comprises a valve system **114** having a top subsystem **114A** in fluid communication with top **112** of vessel **111** and a bottom sub system **114B** in fluid communication with bottom opening **113**. Subsystems **114A**, **114B** are arranged to control and regulate introduction and evacuation of gas **90** and liquid **80**, respectively. Valve system **114** is arranged to pressurize gas **90** by introducing pressurizing liquid **80** into vessel **111**, evacuate pressurized gas **90A** through top opening **112** upon reaching a specified pressure and introduce gas **90** into vessel **111** by evacuating pressurizing liquid **80** through bottom **113** of vessel **111**.

[0026] Vertical vessel **111** further comprises a layer of water-immiscible liquid **70** upon a layer of aqueous salt solution **60**. The layers are arranged to separate pressurizing liquid **80** from gas **90** during the pressurizing and the suction of gas **90**. Liquids **60**, **70** are selected such that the density of pressurizing liquid **80** is higher than the density of aqueous salt solution **60**, which is in turn higher than the density of water-immiscible liquid **70**. Such selection of the densities (at working temperatures and pressures) is arranged to maintain layer of aqueous salt solution **60** on top of pressurizing liquid **80** and to maintain layer of water-immiscible liquid **70** on top of the layer of aqueous salt solution **60**.

[0027] In certain embodiments, gas **90** goes through a preliminary purification of the initial raw material to remove harmful impurities. Then, gas goes through compression (at **111**) and condensation (at **115**) at the expense of its cooling by external coldness-transfer medium (cooling units **115**, see below) refrigerated in the loop of its circulation of the previous stage of the refrigerating cascade, the gaseous phase in each stage of such refrigerating cascade is compressed in vertical vessels **111** arranged in sea water.

[0028] For this purpose, after filling vessel **111** with gaseous medium **90**, a volatile and water-immiscible heavy non-aqueous liquid **80** is fed from a higher level into the lower part of each vessel **111**, under a layer of water-salt medium **60**, whose density is smaller than that of non-aqueous liquid **80**, and which is screened e.g., by liquid hydrocarbon **70**, having a density which is smaller than that of water-salt medium **60**.

[0029] After pressing out compressed gas **90A** by a rising column of heavy liquid **80**, the suction of the next portion of gaseous medium **90** is realized by evacuating the main part of heavy non-aqueous liquid **80** out of vertical vessel **111**.

[0030] The return of volatile heavy non-aqueous liquid **80** from vertical vessels **111** to the upper level is realized by its regasification in gasifier **120** (The term gasifier is used in the present disclosure in its physical meaning, i.e., it is a device that turns liquid to gas) at underwater conditions at the expense of heat exchange (e.g., coil **121**) with the external heat-transfer medium (e.g., steam **30**), with a subsequent discharge of the forming non-aqueous vapors **80A** to the uppermost height mark for condensation in condenser **130** via insulated pipe **122**. After that, non-aqueous heavy liquid **80**, after condensing at the uppermost level, is fed by gravity again (in container **140**) to the base of each vertical vessel **111**, under the layer of water-salt medium **60** screened by liquid hydrocarbon **70**.

[0031] In certain embodiments, pressurizing liquid **80** may comprise e.g., various incombustible and fire- and explosion-proof organic substances with a specified set of thermodynamic, rheological and hygiene and sanitary properties can be used as the volatile and water-immiscible heavy non-aqueous liquid. They are, e.g., completely (or partially) halogenated hydrocarbons of the alkane homologous series, such as perfluorocyclopentane, trifluorobromoethane, hexafluorochlorobromopropane, perfluoropentane, dibromofluoromethane or difluorodibromomethane or their mixtures.

[0032] In certain embodiments, aqueous salt solution **60** may comprise various solutions of mineral and organic salts in fresh (or sea) water with the density smaller than that of non-aqueous medium, such as solutions of calcium or magnesium nitrates, potassium, zinc and calcium bromides, potassium carbonates, formiates and acetates, various halides of other alkali metals, as well as compositions prepared on the basis of fresh (or sea) water, which contain, side by side with mineral salts, ethylene glycol, glycerin and other multi-component water-salt systems characterized not only by a lower specific weight in comparison with halogenated hydrocarbons, but also by a sufficiently low freezing temperature, can be used as water-salt media covering the column of the volatile heavy liquid.

[0033] In certain embodiments, water-immiscible liquid **70** may comprise various water-immiscible aliphatic or aromatic organic compounds having a low freezing temperature and the density smaller than that of mineral (organic) salts solutions **60**, for example, hexane or toluene, can be used as liquid hydrocarbon screening the water-salt medium covering the column of the volatile liquid.

[0034] Pressurized gas **90A** may be liquefied by a cooling unit **115**, as explained in detail below.

[0035] The absence of any mechanical devices with electric drives for compressing gaseous media in the cascade method of methane liquefaction in each stage of such a cascade, and their compression in underwater vertical vessels at the expense of pressing the gaseous phase out of such cylinders by feeding non-aqueous heavy liquids **80** with a specified set of physical and other properties under the layer of water-salt medium **60**, allows not only a drastic decrease in the cyclicity of the operation of such piston compressors that do not contain any moving mechanical parts, but also practically completely get without electric energy consumption for the realization of such a process.

[0036] Besides, underwater placement of high-pressure vessels **111** allows a considerable decrease in their materials output ratio (external hydrostatic pressure of sea-water compensates the internal pressure, which makes it possible to make such equipment with thinner walls).

[0037] The absence of high-speed mechanical compressor equipment with powerful electric drives not only reduces the price of the instrumental design of the process of the invention, but also significantly increases the safety of operation of such sea-bottom gas field.

[0038] Advantageously, all distinguishing features of the present invention are organically interconnected, and their mentioned combination allows the achievement of the object of the invention. The invention is however not to be understood as being limited by the details of the implementation that is exemplified below.

[0039] Embodiments of the invention, illustrated e.g., in **Figures 1** and **2**, comprise an underwater gas pressurization unit **110** comprising at least one vertical vessel **111** arranged to receive gas **90** through a top **112** of vessel **111** and a pressurizing liquid **80** through a bottom **113** of vessel **111**, and further comprising a layer of water-immiscible liquid **70** upon a layer of aqueous salt solution **60**. A density of pressurizing liquid **80** is higher than a density of aqueous salt solution **60**, which is in turn higher than a density of water-immiscible liquid **70**, to maintain the layer of aqueous salt solution **60** on top of pressurizing liquid **80** and to maintain the layer of water-immiscible liquid **70** on top of the layer of aqueous salt solution **60**. Underwater gas pressurization unit **110** further comprises a valve system **114** arranged to pressurize gas **90** by introducing pressurizing liquid **80** into vessel **111**, evacuate pressurized gas **90A** through top opening **112** upon reaching a specified pressure and introduce gas **90** into vessel **111** by evacuating pressurizing liquid **80** through bottom opening **113**. Any of openings **112** and **113** may comprise a plurality of openings. In certain embodiments, separate openings may be used to introduce and evacuate gas **90** (as top opening **112**) and liquid **80** (as bottom opening **113**).

[0040] In certain embodiments, underwater gas pressurization unit **110** may further comprise a delivery unit **125** in fluid communication with valve system **114B**, arranged to receive pressurizing liquid **80** from underwater gas pressurization unit **110** and deliver pressurizing liquid **80** to underwater gas pressurization unit **110**.

[0041] In certain embodiments, and with reference to the detailed example below, delivery unit **125** may comprise a gasifier **120**, such as a boiler **120**, arranged to gasify pressurizing liquid **80**; a condenser **130** located at a specified underwater depth and arranged to condense gasified pressurizing liquid **80A**; a heat insulated pipework **122** arranged to deliver gasified pressurizing liquid **80A** from gasifier **120** to condenser **130**; and a container **140** such as underwater storage **140**, arranged to receive condensed pressurizing liquid **80** and deliver by gravity pressurizing liquid **80** to valve system **114** (e.g., to valves **114B**).

[0042] In certain embodiments, underwater gas pressurization unit **110** may comprise two vertical vessels **111** which are arranged to operate reciprocally, one vessel pressurizing gas **90** while the other vessel receiving gas **90**.

[0043] Underwater gas pressurization unit **110** may be associated with a natural gas production platform **20** and receive natural gas as gas **90** from platform **20**. Liquefied natural gas **90** may be stored in underwater storage **92** or be delivered to the shore. Vessels **111** are arranged to withstand underwater pressure, with respect to the operation conditions of unit **110**. Underwater gas pressurization unit **110** may further be arranged to compress and/or liquefy other gases or gas mixture. In certain embodiments, underwater gas pressurization unit **110** may be arranged to compress and/or liquefy coolants that are used to liquefy natural gas **90**, as illustrated below.

Multiple underwater gas pressurization units **110** may be arranged as a cascade to compress gas **90** step-wise, each stage of the cascade receiving compressed gas and further compressing the received gas. Multiple underwater gas pressurization units **110** may be arranged in a cascade to compress and liquefy several types of gases, having rising critical point temperatures, to enable cooling of the last gas in the cascade by sea water, e.g., by deep sea water. In such an arrangement, the cooling effect of sea water is gradually intensified to enable cryogenic cooling of the first gas in the cascade. A non-limiting detailed example is presented below.

[0044] **Figure 3** is a high level schematic block diagram of an underwater natural gas liquefaction system **100**, according to some embodiments of the invention; **Figure 4** is a high level schematic illustration of underwater natural gas liquefaction system **100**, according to some embodiments of the invention.

[0045] In certain embodiments, underwater natural gas liquefaction system **100** may comprise three underwater gas pressurization units **110A**, **110B**, **110C** arranged as a cooling and pressurizing cascade for efficiently liquefying natural gas.

[0046] A first unit **110A** may be arranged to pressurize natural gas **90** and a natural gas cooling unit **115A** may be arranged to liquefy pressurized natural gas **90A** (to yield liquid natural gas **91**) using a first coolant **50**.

[0047] A second unit **110B** may be arranged to pressurize first coolant **50** and a first cooling unit **115B** may be arranged to liquefy pressurized first coolant **50A** (to yield liquid first coolant **51**) using a second coolant **40**. Liquid first coolant **51** is used in natural gas cooling unit **115A** to cool pressurized natural gas **90A**.

[0048] A third unit **110C** may be arranged to pressurize second coolant **40** and a second cooling unit **115C** may be arranged to liquefy pressurized second coolant **40A** (to yield liquid second coolant **41**), possibly using ambient sea water. Liquid second coolant **41** is used in first cooling unit **115B** to cool pressurized first coolant **50A**.

[0049] In certain embodiments, system **100** may comprise additional stages using additional coolants, or several pressurization stages (each with corresponding vessels **111**) for each coolant and so forth. The number and type of coolants and the number and specifications of pressurization units **110** may be determined according to sea conditions (depth, surface temperatures, construction limitations) and operational considerations.

[0050] First coolant **50** may be selected to have its critical point at a higher temperature than natural gas **90** and second coolant **40** is selected to have its critical point at a higher temperature than first coolant **50**. In such configuration, the cooling power of sea water is amplified by using coolants with decreasing critical point temperature until enabling cooling compresses natural gas **90A**.

[0051] Natural gas **90** produced from the sea bottom (as a natural gas source **89**) for liquefaction by platform **20** may be prepared by its dewatering from water vapors and purification (if necessary) from harmful impurities, such as hydrogen sulfide and carbon dioxide. Then, natural gas **90** may be introduced by suction into one of underwater vertical vessels **111** by discharging the column of volatile heavy liquid **80** screened by a layer of water-salt medium **60** covered with liquid hydrocarbon **70**, as explained above.

[0052] Natural gas **90** may be compressed in vessels **111** with a subsequent pressing-out of natural gas portion collected in the vertical underwater vessel **111** by feeding a volatile heavy liquid into such a cylinder **111** from a higher level under the layer of water-salt medium **60** remaining near its base.

[0053] Subsequently, system **100** may carry out cooling and condensation of compressed natural gas **90A**, at the expense of evaporation of a low-boiling external coldness-transfer medium, e.g., first coolant **50**. The natural gas, being under elevated pressure, is pressed-out for liquefaction from underwater vertical vessel **111** by a rising column of the volatile heavy liquid **80**.

[0054] The liquefied natural gas may be accumulated in underwater storage **92** with its subsequent shipping and delivery to sea-shore consumers by pipeline transportation or by sea shipping in specialized tankers.

[0055] Pressurizing liquid **80** may be introduced into vessels **111** by gravity, utilizing height differences which are available in the sea. For this purpose, pressurizing liquid **80** goes through underwater regasification of volatile heavy liquid **80** discharged from vertical underwater vessels **111** (during gas suction into them) by an external heat-transfer medium such as gasifier **120**, with a subsequent direction of the formed vapors **80A** to condensation realized at a higher mark by their cooling with sea water (in condenser **130**, cooled by propeller **135**). After raising pressuring liquid **80** in gas form **80A**, liquid **80** may be re-introduced into vessels **111** under gravitational action, as illustrated below.

[0056] Container **140** is used to accumulate volatile heavy liquid **80** in a collecting tank established at the upper level, with a subsequent feed of liquid non-aqueous medium **80** under the layer of water-salt solution **60** remaining in vertical vessels **111** after the suction of the subsequent portion of gas **90** into them.

[0057] Another underwater gas pressurization unit **110** may be used for suction of vapors of the external coldness-transfer medium **50** (after the evaporation of coolant **50** was used to take away the natural gas condensation heat) into one of vertical vessels **111** in the refrigerating cascade (see detailed example below), with its subsequent pressing out of cylinder **111** realized in a similar way, i.e., by feeding of volatile heavy liquid **80** under the layer of water-salt solution **60** remained in this vessel **111**.

[0058] Subsequently, system **100** may carry out the cooling of vapors of tailing coldness-transfer medium **50** pressed out of vertical vessel **111**, which cooled natural gas **90**, and its condensation by the evaporation heat take-off from other, less low-boiling (in comparison with methane) coldness-transfer medium, which turns round, in its turn, in its own circulation loop preceding the refrigerating cascade stage. All heat-transfer mediums, the heating of which realize the transition of volatile heavy liquid from liquid to gaseous state in all stages of the cascade, may be cyclically moved through system **100**.

Example

[0059] In the following non-limiting example, pressurized natural gas **80A** may be cooled by ethane as first coolant **50**; Pressurized first coolant **50A** may be cooled by propane as second coolant **40**; Pressurizing liquid **80** may be difluorodibromomethane; Aqueous salt solution **60** may be calcium bromide aqueous solution; and water-immiscible liquid **70** may be liquid hydrocarbon.

[0060] Natural gas **90** may be fed from source **89** to liquefaction after drying-off water vapors and purification from hydrogen sulfide and sucked into one of vertical underwater vessels **111A** and **111B** operating e.g., in opposite phases.

[0061] Natural gas sucking-in occurs due to the discharge of difluorodibromomethane column (density 2.28 g/cm^3, boiling point 24.5°C) filling such working cylinder.

[0062] Such low-boiling liquid obtained owing to alternate discharge of vertical vessels **111A** and **111B** is fed for regasification to boiler **120** heated by water vapor injected into its coil **121** from a steam turbine (not shown) installed on drilling platform **20**, which is part of the steam power unit. Condensate formed as a result of condensation of this external heat-exchange medium is pressed out of coil **121** by the entering fresh vapor back to drilling platform **20**, where this hot water is injected again into the steam-boiler (not shown) by a high-pressure pump (not shown).

[0063] To avoid mixing of natural gas sucked into vessels **111A** and **111B** with difluorodibromomethane vapors, a column of such volatile heavy liquid is screened by layer **60** of calcium bromide aqueous solution – a low-freezing water-salt liquid immiscible with organic environment, whose density is lower than that of difluorodibromomethane (depending on the concentration and temperature, the density of calcium bromide solutions can reach 1.82 g/cm^3). It is characterized by anomalously low freezing point depending on the ratio of the components of such antifreeze.

[0064] In turn, this layer **60** of water-salt medium screening the column of difluorodibromomethane is flooded by a layer of hexane **70** as a non-limiting example for the second coolant. Hexane may be used as second coolant **70** as it is the water-immiscible liquid hydrocarbon with the lowest density in this series of liquids (0.66 g/cm^3).

[0065] However, other water-immiscible low-freezing hydrocarbon liquids, such as, e.g., toluene (density 0.87 g/cm^3), or their mixtures, whose vapors in natural gas cannot damage consumer properties of the latter, can be used as such uppermost liquid coverage.

[0066] Such a double liquid isolation of the gaseous phase in vertical vessels **111** from the volatile non-aqueous liquid prevents both the penetration of the vapors of difluorodibromomethane (which is not just incombustible, but one of the most efficient fire-fighting agents today) into the compressed natural gas, and methane moistening by water vapors that can exist above the surface of any solutions of mineral (organic) salts in water.

[0067] Organic vapors formed in boiler **120** at difluorodibromomethane transition from liquid to gaseous state go up through heat-insulated tract **122** to condenser **130** installed under drilling platform **120**, in the upper layer of sea-water having (depending on the distance from the sea surface area) an average daily temperature in summer 12 to 14°C. (In case of natural gas production in low latitudes of the world ocean, if the temperature of the upper sea-water layer is close to 24°C, perfluoropentane can be used as the volatile heavy liquid instead of difluorodibromomethane. The former has a somewhat lower density 1.62 g/cm^3, but a higher condensation temperature equal to 29.3°C. Otherwise, condenser **130** should be submerged to a greater depth, where sea-water is colder in any season).

[0068] To improve the conditions of difluorodibromomethane condensation heat removal, condenser **130** is washed by sea water pumped through the latter by external marine propeller **135**.

[0069] Difluorodibromomethane **80** converted in this way into the liquid state is accumulated in underwater storage **140,** wherefrom it is fed to natural gas compression by a vertical stand pipe **122** to the base of underwater vertical vessel **111B** adjacent to vessel **111A**, said vessel **111B** being completely filled by that time with methane in the process of emptying the working space of such vertical cylinder from the main volume of its previous liquid content.

[0070] For this purpose, liquid difluorodibromomethane is fed from underwater storage **140** under layer **60** of low-freezing water-salt medium remaining in vessel **111B**, which screens the rising column of such volatile liquid.

[0071] In certain embodiments, system **100** comprises a delivery unit **125** which may comprise comprises a gasifier **120**, such as boiler **120**, arranged to gasify the pressurizing liquid; a condenser **130** located at a specified underwater depth and arranged to condense gasified pressurizing liquid **80A**; a heat insulated pipework **122** arranged to deliver gasified pressurizing liquid **80A** from gasifier **120** to condenser **130**; and a container **140** such as underwater storage **140**, arranged to receive condensed pressurizing liquid **80** and deliver by gravity pressurizing liquid **80** to valve system **114** (e.g., to valves **114B**).

[0072] Due to the rise of difluorodibromomethane **80** level in cylinder **111**, the volume that is not flooded with liquid medium above the surface of double liquid screen (layers **60** and **70**) covering the column of non-aqueous liquid **80** starts gradually to diminish. It leads to the compression of methane **90** contained in vessel **111B**. At the flooding of vertical vessel **111** with liquid medium **80** by 90%, the pressure of methane **90** remaining above the surface of hexane layer **70** increases tenfold. However, to raise the temperature of natural gas liquefaction from –161.5°C (its liquefaction point at the atmospheric pressure) to the maximal possible, i.e. at the critical point (–82.5°C), its pressure should be brought to at least 4.49 MPa.

[0073] Hence, after only about 2.2% of free geometric space of vertical vessel **111** must remain above the surface of water-salt medium **60** screened with liquid hydrocarbon **70**. Natural gas **90** compressed to 4.5 MPa can be completely liquefied at its subsequent cooling down to the temperature on the order of –83 °C. In certain embodiments, several vessels **111** may be used to build several compression stages, allowing a gradual compression of natural gas **90**.

[0074] In certain embodiments, container **140** may be arranged to provide a specified head above vessels **111**, to enable gravitation supply of pressurizing liquid **80** to vessels **111**. For example, to achieve such extent of natural gas compression, the level of liquid difluorodibromomethane **80** in underwater storage **140** (communicating by vertical stand pipe **122** with any of vertical working vessels **111** where gases **90**, **50**, **40** are compressed), in order to equilibrate such pressure, should exceed the height mark of the surface of double liquid screen (**60**, **70**) covering the column of volatile liquid, which supports the compressed gas **90A**, by a head of minimum **201** meters, taking into account the fact that the density of such non-aqueous medium exceeds water density 2.28-fold.

[0075] Thus, when using difluorodibromomethane as a working medium **80** of such thermodynamic cycle, the bottom of underwater storage **140** of such heavy liquid **80** should be vertically apart of its upper level in vertical vessels **111** by a head of at least 201 meters (at the natural gas compression ratio equal to 45, i.e., from the atmospheric pressure of 0.1 MPa to its working value of 4.5 MPa).

[0076] In certain embodiments which utilize, as pressurizing liquid **80**, perfluoropentane at sea gas fields in tropical latitudes (as a more easily condensable liquid) instead of difluorodibromomethane, this height drop should be 1.4 times greater, i.e**.,** 283 meters, taking into account that perfluoropentane density equals 1.62 g/cm^3, and not 2.28 g/cm^3.

[0077] With growing sea depth, sea bottom closeness to drilling platform **20** does not limit the height drop between the columns of heavy liquid **80** used in such communicating vessels **111**. Then, other volatile liquids **80** with even lower densities, such as hexafluorochlorobromopropane (density 1.55 g/cm^3) can be used as working media in the thermodynamic cycles. Their vapors **80A** can be condensed in the uppermost (the most heated with solar radiation) sea water layers even on the hottest summer days (hexafluorochlorobromopropane condensation temperature is 35.7 °C). In his case, vertical vessels **111**, in which natural gas **90** is compressed to such pressure, can be submerged to even greater depth until they reach sea bottom.

[0078] In other embodiments, in case of underwater gas production in the coastal zone, at small depths, even a heavier non-aqueous liquid **80**, such as dibromofluoromethane (density 2.42 g/cm^3, boiling point 64.5 °C), can be used to fill a U-shape hydraulic system, in order to reduce the height of such water tower. In these embodiments, at least some of vessels **111** may be U-shaped, to reduce the required specified head for gravitational delivery of pressurizing liquid **80**. In this case, the difference in the levels of liquid contents of such communicating vessels is even smaller, and a head of 194 meters may suffice. When using tribromofluoromethane (density 2.71 g/cm^3, boiling point 105 °C), this difference is a bit less than 170 meters, etc. Similarly, pressurizing liquid **80** may be selected to enable operation in given sea location and topography, and vessels **111** may be designed accordingly. Pressurizing liquid **80** and vessels **111** may be designed and selected to provide the required head of pressurizing liquid **80** with respect to at least one of vessels **111** at a given sea location.

[0079] At the operation of check valves **114A** tuned to the pressure of 4.5 MPa, natural gas alternately compressed down to this pressure in vertical vessels **111** is brought out of them for cooling and condensation.

[0080] Pre-cooling of compressed natural gas **90A** may be realized in heat exchanger **150A** installed at the depth exceeding **100** meters. It can be attributed to the fact that the warm water store in the world ocean with the temperature of 10°C and more makes up only about 8% of its total volume. It is concentrated in the upper sea water layer less than **100** m thick. Below this layer, with growing depth, water temperature gradually falls to 1 to 3°C. This is the temperature of about 75% of the entire volume of the world ocean. Such temperature regime in the deep part of seas and oceans remains practically unchanged all the year round and round the clock. Respectively, by pumping such free-of-charge coldness-transfer medium through heat exchanger **150A** by marine propeller **155A**, the temperature of compressed natural gas passing through it can be reduced to 3 to 5°C.

[0081] Gaseous medium pre-compressed down to 4.5 MPa and cooled in heat exchanger **150A** down to 4°C is fed, first, to recuperative heat exchanger **160A** and then to coldness exchanger **166A** refrigerated by evaporating a first coolant **51** such as liquid ethane as final cold-transfer medium **50**. Coldness exchanger **166A** may be located in the circulation loop of the stage of such refrigerating cascade, which precedes methane liquefaction. Note: in the present application, the term "coldness exchanger" is used to refer to a heat exchanger that operated to cool the respective fluid. The term "coldness-transfer medium" refers to any of the coolants in the system, e.g., first and second coolants **50**, **40** as well as sea water at different temperatures.

[0082] Owing to the cryogenic temperature (– 88.7°C) achieved in coldness-exchanger **166A**, at the transition of liquid ethane **51** (preliminarily throttled in regulating valve **167A**) from liquid **51** to gaseous state **50**, cold natural gas compressed in vertical vessels **111** to the pressure close to critical one, becomes liquid. After that, liquefied methane **91** is brought out, as a ready product, to underwater storage **92**, wherefrom it is shipped afterwards to customers by gas-tankers or delivered to the beach in the liquid state by underwater pipelines.

[0083] Other cryogenic liquids, such as ethylene (normal boiling point –103.5°C) or perfluoromethane (normal boiling point –127.9°C) can be used as final coldness-transfer media that can liquefy, besides ethane, compressed natural gas. Here the pressure of methane compression should not necessarily reach 4.5 MPa, – in this case, natural gas can be liquefied at a lower pressure, too. Respectively, the head provided by container **140**, i.e. the height difference between the levels of volatile heavy liquid **80** in the "water tower" (container **140**) and in vertical vessels **111** communicating with it can be also reduced.

[0084] Gaseous ethane **50** leaving coldness-exchanger **166A**, which has passed its coldness to pre-refrigerated methane **90A**, may be fed to its liquefaction realized in this multi-stage system exactly in the same way.

[0085] For this purpose, ethane **50** leaving coldness-exchanger **166A** after regasification is fed to recuperative heat exchanger **160A**, where it passes its remaining artificial coldness to compressed methane. After that, such tailing coldness-transfer medium is compressed. For this purpose, first coolant **50** such as ethane is sucked into one of vertical vessels **111** of second gas pressurizing unit **110B** working according to the same principals as first gas pressurizing unit **110A**, with vessels **111** in opposite phases owing to liquid difluorodibromomethane from storage **140** alternately fed into them (more exactly, to their base) under the layer of water-salt medium.

[0086] First cooling unit **115A** hence comprises heat exchanger **150A** equipped with propeller **155A** and recuperative heat exchanger **160A** with coldness-exchanger **166A**.

[0087] Difluorodibromomethane volumes discharged from vessels **111** after sucking-in recurrent portions of ethane are also fed for regasification into boiler **120**. From there, organic vapors of such volatile liquid are stripped by the heat of the external heat-transfer medium (in the present case, the heat of water vapor condensed in coil **121**) into condenser **130** installed at the upper level. This working liquid condensed as a result of heat exchange with sea water is accumulated again in storage **140**, wherefrom it is fed for the next flooding of one of the vessels **111** of second unit **110B** at ethane compression up to elevated pressure.

[0088] In contrast to methane (as gas **90**), ethane (as first coolant **50**) is much easier to liquefy (boiling point of this cryogenic liquid at atmospheric pressure is not –161.5°C, as for methane, but almost twice higher, more exactly, –88.6°C. The critical temperature of ethane liquefaction is positive and equals 32.3°C, which nearly always allows the use of sea water as a free-of-charge coldness-transfer medium for the removal of condensation heat of ethane compressed up to the critical pressure over the greatest part of the world ocean). In such embodiments, system **100** may operate with first coolant **50** to cool compressed gas **90A**, the first coolant **50** may be liquefied by ambient low sea temperatures.

[0089] Other embodiments may be designed to operate even in the hottest summer days, in shallow areas of some natural reservoirs (e.g., the Caspian sea), in which sea-water temperature can increase up to a higher level.

[0090] In this case, even ethane **50** compressed to a critical pressure value (4.7 MPa) in vertical vessels **111** cannot be easily condensed with a high efficiency in a compact heat-exchange facility by a coldness-transfer medium of such a low refrigerating potential.

[0091] Hence, for a guaranteed maintenance of a high productivity of natural gas liquefaction process in any meteorological conditions of the operation of a sea gas field, ethane condensation may also be realized using artificial coldness produced in the first stage of such refrigerating cascade, where propane or ammonia can be used as a working medium.

[0092] For this purpose, ethane **50** may be compressed in vertical vessels **111** of second unit **110B** to a more moderate pressure than the critical pressure (4.7 MPa). Ethane **50** may first be cooled by sea water in heat exchanger **150B** equipped with propeller **155B**, and then ethane **50** may be fed into recuperative heat exchanger **160B**. Heat exchanger **160B** may be arranged to remove the residues of artificial coldness carried out of coldness-exchanger **166B** by a second coolant **41** such as propane, which is regasified in heat exchanger **166B**. Second coolant **41** may be passed through preliminary throttling (after its liquefaction as described below) in regulating valve **167B**.

[0093] Second cooling unit **115B** hence comprises heat exchanger **150B** equipped with propeller **155B** and recuperative heat exchanger **160B** with coldness-exchanger **166B**.

[0094] Thus, the compressed first coolant **50** (e.g., ethane) is condensed in coldness exchanger **166B** at the expense of the heat of the phase transition of the second coolant (e.g., propane) from liquid **41** into gaseous state **40**.

[0095] Propane **40** circulating in the first stage of such refrigerating cascade is also the most easily liquefied gas of all coldness-transfer media used in such a system of methane liquefaction.

[0096] Propane condensation point at atmospheric pressure is not a cryogenic value. It exists in nature (–42.6°C) and is quite comparable with meteorological conditions of atmospheric air above the area of the Arctic Ocean during winter polar nights. Critical temperature of its liquefaction equals –96.8°C. Its vapor pressure corresponding to such critical temperature is also considerably lower (4.1 MPa) than that of ethane (4.7 MPa). Therefore, it is not always reasonable to compress propane down to the pressures characteristic of ethane compression in vertical vessels **111** of second unit **110B**.

[0097] Accordingly, propane liquefaction in the first stage of such refrigerating cascade may be realized in a similar way to that of ethane and methane, but under milder technological conditions. While gas **90** (e.g., methane) is compressed in vessels **111** of first unit **110A**, and first coolant **50**

(e.g., ethane) is compressed in vessels **111** of second unit **110B** - second coolant **40** (e.g., propane) may be compressed in vessels **111** of third unit **110C**.

[0098] For this purpose, two vertical vessels **111** of a third gas compressing unit **110C** operating in opposite phases are used. Gaseous second coolant **40** (e.g., propane) is alternately sucked into them after regasification (in coldness-exchanger **166B)** and recuperative heat exchange (in heat-exchanger **160B)** is compressed in such vertical cylinders up to a pressure that is the higher, the warmer sea water, which is used for cooling this gas in heat exchanger **150C** equipped with propeller **155C**.

[0099] Propane **40**, which is alternately compressed in vertical vessels **111**, passes preliminary cooling with sea water in heat exchanger **150C** and then is fed to liquefaction realized in an even more deep-water condenser **160C** washed with even colder sea water pumped through it by propeller **165**.

[00100] In this connection, it may be necessary to use colder sea-water when condenser **160C** is fixed at a much lower geodesic mark than heat exchanger **150C**, which ensures high propane condensation efficiency in any season and around the clock. In other embodiments, cooling unit **115C** may be constructed similarly to cooling unit **115B**. In certain embodiments (e.g., if first coolant **50** may be sufficiently cooled at deep sea temperatures), cooling unit **115B** may be constructed as the illustrated cooling unit **115C**.

[00101] Propane **41** liquefied in this way in condenser **160C** (at the expense of free-of-charge refrigerating potential of deep sea water) is throttled in regulating valve **167B** and fed after that to coldness-exchanger **166B**.

[00102] Boiling at atmospheric pressure in coldness-exchanger **166B**, propane (normal boiling point of liquid propane being –42.6°C), passing from liquid to gaseous state, takes off condensation heat from ethane. This leads to liquefaction of such coldness-transfer medium pre-compressed beforehand in vertical vessels **111** of second unit **110B**, which is contained in the circulation loop of the second stage of underwater refrigerating cascade.

[00103] Final recuperation of artificial coldness removed from coldness-exchanger **166B** by propane vapors is realized in recuperative heat-exchanger **160B** at the expense of coldness exchange between gaseous propane and compressed ethane fed for condensation.

[00104] Third cooling unit **115C** hence comprises heat exchanger **150C** equipped with propeller **155C** and deep-water condenser **160C** with propeller **165**.

[00105] Propane **41** regasified in this way in coldness-exchanger **166B** is returned for compression into one of vertical vessels **111** of third unit **110C**, i.e. to the head of technological process, thus, closing the circulation loop of coldness-transfer medium, which is the working medium of the first stage of underwater refrigerating cascade.

[00106] Thus, at high production standards and trouble-free operation of the equipment, all cooling agents (e.g., first and second coolants **50**, **40**) used in such multi-stage technological cascade are practically not consumed, since the cycles of their circulation with respect to these substances are practically entirely closed.

[00107] Advantageously, the use of the invention may make it possible to overcome well-known deficiencies of traditional multi-stage methods of cascade liquefaction of natural gas not only due to the necessity of arranging refrigerating equipment on the working floor of a drilling platform of extremely limited production area, but also due to the degeneration of a rigid connection between the level of its thermodynamic perfection and the unit production capacity of methane-liquefying facility in the technological process of the invention.

[00108] Moreover, with growing productivity and, hence, increasing height of vertical underwater vessels **111** of units **110A**, **110B** and **110C** (at the development of deep-water and extra-deep-water sea gas fields), the cyclicity of the process of compression of corresponding gases even decreases, and additionally compressing all working media of each stage of the refrigerating cascade uses thermal energy instead of electric power. Its generation is incomparably cheaper for sea gas fields than electricity generation by expensive ship power plants and the use of electric drive.

[00109] An additional advantage of arranging huge working cylinders of such hydraulic compressor in underwater conditions is an increase in the efficiency of the removal of gas compression heat with an increase in their vertical overall dimensions. The point is that most of sea gas fields discovered by today are located at deep and super-deep parts of the world ocean, which allows the erection of such vertical vessels **111** hundreds and thousands meters high. Thus, the most part of the surface of natural heat exchange of such compression equipment with the environment turns out to be submerged into sea water having the year-round temperature 1 to 3°C, which allows an essential decrease in the total energy consumption by the system of artificial coldness generation at the expense of a removal of a significant part of heat taken from natural gas by such free-of-charge coldness-transfer medium.

[00110] Advantageously, operating below sea level also reduces the ambient operation temperature. Thus, natural gas liquefaction is more effective and particularly more thermally efficient than liquefaction above the sea surface or on the shore.

[00111] Furthermore, the invention is of particular interest for developing deep and extra-deep sea gas fields. It is due not only to the fact that with sea depth growth, sea-water temperature decreases, and it becomes possible to install higher vertical underwater vessels **111**, but also to the hydrostatic pressure growth. Thus, the internal pressure of compressed gas contained in any underwater vessels is countered by the external hydrostatic pressure. This decreases the material capacity of the principal technological equipment, which makes it cheaper and ensures, at the same time, a higher safety of its operation.

[00112] Even greater prospects of a decrease in power consumption for the liquefaction of methane produced on the sea bottom arise in case of the development of deep sea-water gas fields located in zones of elevated heat-release activity of the Earth's interior. In such cases, besides drilling gas wells, wells reaching rocks with elevated temperature may be drilled under the sea bottom from drilling platform **20**. When the circulation of heat-transfer medium (which can regasify, passing through coil **121** of boiler **120**, such volatile liquid as difluorodibromomethane) in this loop is organized, the consumption of commercial power resources by such technological process becomes even smaller.

[00113] Taking into account that methane itself is the main energy carrier at sea gas fields, the use of free-of-charge heat of the Earth's interior for closing compression cycles for all kinds of gaseous media in the method of the invention of natural gas compression ensures an additional increment of the production capacity of such drilling platform with respect to its final product.

[00114] In certain embodiments, the use of the present invention allows the development of sea gas fields located at a distance of hundreds and thousands kilometers from ocean shores irrespective of natural gas occurrence depth. After all, transportation of one kg of gaseous methane to far and to extra-far distances is incomparably more expensive than that of one kg of liquid natural gas, since the density of one cubic meter of gaseous methane is only 720 g/m^3, while one cubic meter of liquid methane weighs about 450 kg, i.e., 625 times more. Besides, liquefied methane, in contrast to natural gas, is practically incompressible. Respectively, at its pumping by trunk pipelines, the main power consumption for its delivery to long distances is connected with overcoming friction forces between such extremely low-viscous liquid and the internal surface of the throughway. Meanwhile, at gaseous methane pumping, the main power consumption is connected with its compression, and not transportation.

[00115] **Figure 5** is a high level schematic flowchart illustrating a gas compression and liquefaction method **200**, according to some embodiments of the invention. Method **200** may comprise pressurizing gas, such as natural gas or other gases such as ethane or methane. Method **200** may further comprise cooling the compressed gas to liquefy it. For example, pressurizing the gas may surpass the pressure of its critical point and cooling the compressed gas may thus liquefy the gas. In certain embodiments, method **200** may compress and liquefy natural gas, as illustrated in a non-limiting example below.

[00116] Method **200** comprises pressurizing the gas in at least one vertical vessel (stage **210**), e.g., pressurizing natural gas (stage **211**), by cyclically (stage **235**): (i) introducing the gas into a top of the at least one vertical vessel (stage **212**); (ii) introducing a pressurizing liquid into a bottom of the at least one vertical vessel to pressurize the gas (stage **215**); separating the pressurizing liquid from the gas by a layer of water immiscible liquid which is set upon a layer of aqueous salt solution (stage **220**) ; and evacuating the pressurized gas through the top opening upon reaching a specified pressure (stage **230**). The pressurization may be carried out cyclically (stage **235**), e.g., by introducing the gas by evacuating the pressurizing liquid from the bottom of the at least one vertical vessel (stage **216**). Thus natural gas may be continuously pressurized by introducing and evacuating the pressurizing liquid.

[00117] In certain embodiments, method **200** may further comprise selecting the pressurizing liquid to have a higher density than the aqueous salt solution (stage **222**); selecting the aqueous salt solution to have a higher density than the water immiscible liquid (stage **224**); and selecting the water immiscible liquid to have a higher density than the gas (stage **226**), to maintain the gas on top of the layer of water-immiscible liquid, the layer of water-immiscible liquid on top of the layer of aqueous salt solution and the layer of aqueous salt solution on top of the pressurizing liquid (stage **228**).

[00118] In certain embodiments, method **200** may further comprise delivering evacuated pressurizing liquid by gasification, upwards delivery, condensation and downwards delivery, comprising the following stages: delivering evacuated pressurizing liquid back to the bottom of the vessel (stage **240**); gasifying the evacuated pressurizing liquid (stage **242**); delivering the gasified pressurizing liquid upwards in an insulated pipe (stage **244**); condensing the gasified pressurizing liquid (stage **246**); delivering the condensed pressurizing liquid downwards (stage **248**) and selecting the pressurizing liquid and designing the vessels to provide a specified head of the pressurizing liquid with respect to the at least one vessel at a given sea location (stage **249**).

[00119] In certain embodiments, method **200** may further comprise liquefying the pressurized natural gas by cooling with a first coolant (stage **250**) and selecting the first coolant to have its critical point at a higher temperature than the natural gas (stage **255**). Cooling by the first coolant (stage **250**) may comprise gasifying the first coolant to cool the pressurized natural gas (stage **252**).

[00120] In certain embodiments, method **200** may further comprise pressurizing the first coolant (stage **257**) and liquefying the pressurized first coolant by cooling with a second coolant (stage **260**). Method **200** may further comprise selecting the second coolant to have its critical point at a higher temperature than the first coolant (stage **265**). Cooling by the second coolant (stage **260**) may comprise gasifying the second coolant to cool the pressurized natural gas (stage **262**).

[00121] In certain embodiments, method **200** may further comprise pressurizing the second coolant (stage **267**) and liquefying the pressurized second coolant by cooling with sea water (stage **270**).

[00122] Advantageously, compression by pressurizing liquid **80** is superior to compression in current pistons or other mechanical compression unit in the following aspects. First, the compression heat is dissipated into the liquids and the sea, and does not damage moving parts (e.g., bearings, insulation rings etc.). Second, gas introduction by evacuation of pressurizing liquid **80** is more efficient than using the return stroke of a piston system, especially at high operation speeds. Also, the compression by liquid is more scalable than piston system, which must face the difficulty of increasing inertia of the piston head. Finally, due to the reduction of the number of mechanical parts, underwater operation and flame retarding nature of at least some of the usable pressurizing liquids **80**, the disclosed systems and methods are significantly safer than current systems.

[00123] Advantageously it is an object of the present invention to weaken the fall of energy perfection level of the process with its productivity increase, to simplify the instrumental interpretation, to reduce electrical energy consumption by the system for natural gas liquefaction, as well as to increase the safety degree of marine gas fields.

[00124] In certain embodiments, underwater gas pressurization units and liquefaction systems, as well as pressurization and liquefaction methods are provided. Gas is compressed hydraulically by introduced seawater that operates as pressurizing liquid **80**, which is separated from the gas by a water-immiscible liquid layer. The seawater is delivered gravitationally by utilizing deep sea pressures; the rising water compresses the gas in the top of the compression vessels. Tall, possibly vertical helical vessels may be used to reach a high compression ratio that lowers the liquefaction temperature. Cooling units are used to liquefy the compressed gas, possibly by a coolant which is itself pressurized by a similar mechanism. A cascade having two or more stages of compression and cooling units may be used to allow eventual cooling by ambient seawater. In certain embodiments, the coolant may be selected to be liquefied at surrounding seawater temperatures. The dimensions and forms of the vessels, the coolants and the implementation of the cooling units are selected according to the sea location, to enable natural gas liquefaction in proximity to the gas source. The seawater which is used to pressurize the gas may be used after evacuation to pressurize intrastratal gas in the production stages.

[00125] **Figure 6** is a high level schematic block diagram of an underwater gas pressurization unit **110**, according to some embodiments of the invention. Underwater gas pressurization unit **110** comprises at least one vessel **111**, illustrated in **Figure 6** in two operation states, denoted **111A** for gas pressurization and **111B** for gas suction, as explained below. Vessel **111** is arranged to receive gas **90** through a top **112** of the vessel, e.g., through a top opening, and seawater **80** through a bottom **113** of the vessel, e.g., through a bottom opening. In certain embodiments, seawater **80** is used as pressurizing liquid **80** in the sense of the embodiments disclosed above.

[00126] Underwater gas pressurization unit **110** comprises a valve system **114** having a top subsystem **114A** in fluid communication with top **112** of vessel **111** and a bottom sub system **114B** in fluid communication with bottom opening **113**. Subsystems **114A**, **114B** are arranged to control and regulate introduction and evacuation of gas **90** and seawater **80**, respectively. Valve system **114** is arranged to pressurize gas **90** by introducing seawater **80** into vessel **111**, evacuate pressurized gas **90A** through top opening **112** upon reaching a specified pressure and introduce gas **90** into vessel **111** by evacuating seawater **80** through bottom **113** of vessel **111**.

[00127] Vessel **111** further comprises a layer of water-immiscible liquid **70** arranged to separate seawater **80** from gas **90** during the pressurizing and the suction of gas **90**. Liquid **70** is selected to have an intermediate density between the densities of seawater **80** and gas **90**. The density selection (at working temperatures and pressures) is arranged to maintain layer of water-immiscible liquid **70** on top of seawater **80**.

[00128] In certain embodiments, gas **90** goes through a preliminary purification of the initial raw material to remove harmful impurities. Then, gas goes through compression (at **111**) and condensation (at cooling units **115**, see below).

[00129] In certain embodiments, water-immiscible liquid **70** may comprise aliphatic or aromatic organic compounds or their mixtures, and may have a density smaller than seawater and a freezing temperature below -20°C. For example, water-immiscible liquid **70** may be selected from: hexane, hexane isomers, heptane, heptane isomers, toluene, derivatives thereof and mixtures thereof.

[00130] The absence of any mechanical devices with electric drives for compressing gaseous media in the method of methane liquefaction, and their compression in underwater vertical vessels at the expense of pressing the gaseous phase out of the vessels by feeding seawater **80**, allows not only a drastic decrease in the cyclicity of the operation of such piston compressors that do not contain any moving mechanical parts, but also practically completely get without electric energy consumption for the realization of the process. Besides, the underwater location of high-pressure vessels **111** allows a considerable decrease in their materials output ratio (external hydrostatic pressure of sea-water compensates the internal pressure, which makes it possible to make such equipment with thinner walls). The absence of high-speed mechanical compressor equipment with powerful electric drives not only reduces the price of the instrumental design of the process of the invention, but also significantly increases the safety of operation of such sea-bottom gas field.

[00131] Advantageously, all distinguishing features of the present invention are organically interconnected, and their mentioned combination allows the achievement of the object of the invention. The invention is however not to be understood as being limited by the details of the implementation that is exemplified below.

[00132] Underwater gas pressurization unit **110** may be associated with a natural gas production platform **20** and receive natural gas as gas **90** from platform **20**. Liquefied natural gas **90** may be stored in an underwater storage or be delivered to the shore. Vessels **111** are arranged to withstand underwater pressure, with respect to the operation conditions of unit **110**. Underwater gas pressurization unit **110** may further be arranged to compress and/or liquefy other gases or gas mixture. In certain embodiments, underwater gas pressurization unit **110** may be arranged to compress and/or liquefy coolants that are used to liquefy natural gas **90**, as illustrated below. Multiple underwater gas pressurization units **110** may be arranged as a cascade to compress gas **90** step-wise, each stage of the cascade receiving compressed gas and further compressing the received gas. Multiple underwater gas pressurization units **110** may be arranged in a cascade to compress and liquefy several types of gases, having rising critical point temperatures, to enable cooling of the last gas in the cascade by sea water, e.g., by deep sea water. In such an arrangement, the cooling effect of sea water is gradually intensified to enable cryogenic cooling of the first gas in the cascade. A non-limiting detailed example is presented below.

[00133] Advantageously, disclosed systems and methods ensure the possibility of sea gas field development with the delivery of the produced natural gas in the liquefied form immediately at the production site in underwater conditions, with a simultaneous decrease of volumes of conditioned power resources required for the realization of such a process. In certain embodiments, to achieve this object, the natural gas is sucked into an underwater hollow pipe coil, which is in the filling phase. After that, it is compressed by an ascending column of sea water screened by a layer of immiscible hydrocarbon liquid owing to the ingress of sea water from below, under the layer of non-aqueous liquid, due to a high external hydrostatic pressure. Natural gas is thus compressed to a pressure not less than the critical one, and is fed to liquefaction realized by its cooling and condensation by an external cryogenic cold-carrier, which is located in the loop of its own circulation. After that, most part of the sea water is pumped out of the pipe coil before its filling with the next portion of natural gas at the initial stage of gas field development. At the second stage of the field development, sea water outgoing of the pipe coil compressing natural gas is supplied to flooding underwater gas field.

[00134] Advantageously, the use of external hydrostatic pressure of sea water (fed afterwards to the flooding of shelf gas field at the second stage of its development) for the natural gas compression makes it possible to do without piston compressors that are traditionally used in methane liquefaction cycles and represent not only powerful electric energy consumers, but also rather low-efficiency devices. This makes it possible both to deliver the entire volume of the produced natural gas in the liquefied form directly at the site of its production, and to reduce sharply the power intensity of such gas field development.

[00135] **Figure** 7 is a high level schematic block diagram of an underwater natural gas liquefaction system **100**, according to some embodiments of the invention; **Figure 8** is a high level schematic illustration of underwater natural gas liquefaction system **100**, according to some embodiments of the invention. In certain embodiments, underwater natural gas liquefaction system **100** may comprise two underwater gas pressurization units **110A**, **110B** arranged as a cooling and pressurizing cascade for efficiently liquefying natural gas. A first unit **110A** may be arranged to pressurize natural gas **90** and a natural gas cooling unit **115A** may be arranged to liquefy pressurized natural gas **90A** (to yield liquid natural gas **91**) using a coolant **50**. Coolant **50** may be selected to have its critical point at a higher temperature than natural gas **90**. A second unit **110B** may be arranged to pressurize coolant **50** and a cooling unit **115B** may be arranged to liquefy pressurized coolant **50A** (to yield liquid first coolant **51**) using seawater. In certain embodiments, system **100** may comprise additional stages using additional coolants, or several pressurization stages (each with corresponding vessels **111**) for each coolant and so forth. The number and type of coolants and the number and specifications of pressurization units **110** may be determined according to sea conditions (depth, surface temperatures and construction limitations) and operational considerations.

[00136] Natural gas **90** produced from the sea bottom (as a natural gas source **89**) for liquefaction by platform **20** may be prepared by its dewatering from water vapors and purification (if necessary) from harmful impurities, such as hydrogen sulfide and carbon dioxide. Then, natural gas **90** may be introduced by suction into one of underwater vessels **111** by discharging the column of seawater **80** screened by a liquid hydrocarbon **70**, as explained above. Natural gas **90** may be compressed in vessels **111** with a subsequent pressing-out of natural gas portion collected in the vertical underwater vessel **111** by feeding seawater into cylinder **111** from the surrounding deep sea. Subsequently, system **100** may carry out cooling and condensation of compressed natural gas **90A**, at the expense of evaporation of coolant **50**. The natural gas, being under elevated pressure, is pressed-out for liquefaction from underwater vessel **111** by a rising column of seawater **80**. The liquefied natural gas **91** may be accumulated in an underwater storage **92** with its subsequent shipping and delivery to sea-shore consumers by pipeline transportation or by sea shipping in specialized tankers. Seawater **80** may be introduced into vessels **111** by gravity, utilizing height differences which are available in the sea. Coolant **50** may be pressurized in a similar pressurization unit **110B** and cooled to liquefaction in cooling unit **115**B. Details of system **100** which are illustrated in **Figure** 7 are explained in the example presented below.

[00137] **Figure 9** is a high level schematic flowchart illustrating a gas compression and liquefaction method **300**, according to some embodiments of the invention. Method **300** may comprise pressurizing gas, such as natural gas or other gases such as ethylene or methane. Method **300** may further comprise cooling the compressed gas to liquefy it. For example, pressurizing the gas may surpass the pressure of its critical point and cooling the compressed gas may thus liquefy the gas. In certain embodiments, method **300** may compress and liquefy natural gas, as illustrated in a non-limiting example below.

[00138] Method **300** comprises pressurizing the gas in at least one vessel (stage **310**), e.g., pressurizing natural gas (stage **311**), by cyclically (stage **335**): (i) introducing the gas into a top of the at least one vessel (stage **312**); (ii) introducing seawater into a bottom of the at least one vessel to pressurize the gas (stage **315**); separating the seawater from the gas by a layer of water immiscible liquid (stage **320**); and evacuating the pressurized gas through the top of the at least one vessel upon reaching a specified pressure (stage **330**). The pressurization may be carried out cyclically (stage **335**), e.g., by introducing the gas by evacuating the seawater from the bottom of the at least one vessel (stage **316**). Thus natural gas may be continuously pressurized by introducing and evacuating the seawater.

[00139] In certain embodiments, method **300** may further comprise selecting the water immiscible liquid to have an intermediate density, between the densities of the gas and the seawater (stage **326**), to maintain the gas on top of the layer of water-immiscible liquid and the layer of water-immiscible liquid on top of the seawater in the vessel (stage **328**).

[00140] In certain embodiments, method **300** may further comprise delivering the evacuated seawater into a pressurizing well (stage **340**). In certain embodiments, the evacuated seawater may be delivered into the ambient sea or into one or more pressurizing wells, depending on the production requirements. The delivered seawater may be filtered prior to delivery and pumped into the pressurizing well.

[00141] In certain embodiments, method **300** may further comprise liquefying the pressurized natural gas by cooling with a coolant (stage **350**) and selecting the coolant to have its critical point at a higher temperature than the natural gas (stage **355**). Cooling by the coolant (stage **350**) may comprise gasifying the coolant to cool the pressurized natural gas (stage **352**). In certain embodiments, method **300** may further comprise pressurizing the coolant (stage **357**) and liquefying the pressurized coolant (stage **360**). Pressurizing the coolant **357** may be carried out by method **300**, e.g., according to stages **312**, **315**, **316**, **320**, **330** and **335**.

[00142] Certain embodiments comprise an underwater gas field development method comprising underwater natural gas liquefaction method **300** and delivering the evacuated the evacuated seawater into the pressurizing well to enhance gas production (stage **340**). Method **300** may further comprise developing and enhancing production from an underwater gas field (stage **370**), as well as remotely controlling an amount of delivered evacuated seawater into the pressurizing well (stage **375**) and generating electricity from the flow of delivered evacuated seawater into the pressurizing well (stage **380**).

[00143] In certain embodiments, method **300** may be realized by successive realization of the following main technological operations.

[00144] During the initial development of the gas field: drilling of production and pressure boreholes from the board of drilling platform for opening the underwater gas deposit; equipping the production and pressure boreholes with additional technological equipment, pipelines, auxiliary facilities and stop valves, as well as with means of telemetric control and telemechanical handling of principal production parameters and natural gas liquefaction in underwater conditions, assuring, meanwhile, a total safety of the operation of such sea gas field; and starting natural gas delivery from underwater field by production boreholes.

[00145] Then, the produced natural gas may be compressed by applying the following stages: precooling of the produces natural gas by blind heat exchange with the surrounding sea water; sucking-in of natural gas from producing wells and precooled with sea water into the system of its underwater compression and condensation made in the form of underwater pipe coils working in antiphase with emptying their internal helical space from the most part of sea water (by forced sea water swinging at the first stage of the field development and gravity discharge of sea water by pressure wells into the gas pool after the beginning of intrastratal pressure drop at the second stage of the sea gas field development); and flooding of the pipe coil, after sucking-in natural gas, with sea water supplied from below, its column inside such coil being screened by a layer of water-immiscible hydrocarbon liquid. At that, the compressed gas is pressed out of such hydraulic compressing facility.

[00146] Finally, the compressed natural gas may be cooled and liquefied according to the following stages: cooling of natural gas compressed in the coil with sea water, and then with an external cryogenic cold-carrier; condensation of the compressed natural gas cooled by cryogenic cold-carrier down to the liquefaction temperature; compression and condensation of the vapors of external (with respect to the liquefied natural gas) cold-carrier boiling at the transfer of its cold to the condensing methane in the underwater system of liquefaction of such cryogenic liquid. The system operates according to a similar scheme including a couple of antiphase-operated underwater coils and heat-exchange facilities using sea water as a cooling medium; and returning the regenerated cryogenic liquid into the cycle of methane liquefaction.

[00147] The liquefied natural gas may be accumulated in underwater storage and its subsequent shipment and delivery to coastal consumers by underwater pipeline transport or by sea transport using specialized ships.

[00148] Advantageously, compression by seawater **80** is superior to compression in current pistons or other mechanical compression unit in the following aspects. First, the compression heat is dissipated into the seawater and the sea, and does not damage moving parts (e.g., bearings, insulation rings etc.). Second, gas introduction by evacuation of seawater **80** is more efficient than using the return stroke of a piston system, especially at high operation speeds. Also, the compression by liquid is more scalable than piston system, which must face the difficulty of increasing inertia of the piston head. Finally, due to the reduction of the number of mechanical parts, underwater operation and flame retarding nature of seawater **80**, the disclosed systems and methods are significantly safer than current systems.

Example

[00149] The following is a non-limiting example for a realization of system **100** and units **110** and **115**. Implementation details are to be adjusted with respect to specific locations and requirements.

[00150] After opening the underwater gas field from sea drilling platform **20** (or from a special sea ship) and establishing producing wells **22** and pressure wells **23**, natural gas that ascends to the sea bottom surface through producing well **22** is cooled in an underwater heat exchanger **104** down to the temperature 5-7°C close to that of near-bottom sea water layer (2-4°C). After that, it is sucked into one of antiphase operating pipe coils **111**. Natural gas **90** may be compressed in any configuration of vessels **111** and in vessels **111** having various designs. The following non-limiting example refers to helical vessels **111** which operate pairwise – one vessel compresses gas (e.g., vessel **111A** in **Figure** 7 is illustrated at the end of the compression phase) and the other vessel sucks in gas (e.g., vessel **111B** in **Figure** 7 is illustrated at the end of the suction phase). Vessels **111** are illustrated in a non-limiting manner to have a helical form, referred to in the following as coils.

[00151] In certain embodiments, water-immiscible liquid **70** may comprise various water-immiscible aliphatic or aromatic organic compounds having a low freezing temperature and the density smaller than that of seawater **80**, for example, hexane or toluene. Water-immiscible liquid **70** may comprise hexane (density 0.66 g/cm^3, freezing point -95.3°C) or its isomers (2-methylpentan, freezing point -153.7°C; 3- methylpentane, freezing point -118°C; 2,3-dimethylbutane, freezing point -128.5°C), heptane (density 0.69 g/cm^3, freezing point -90.6°C), as well as its numerous derivatives and other representatives of the alkane homologous series of organic aliphatic compounds.

[00152] At the first stage of gas field development, when gas pressure in the well is high, sea water column **80** flooding pipe coils **111** at the beginning of natural gas sucking-in phase (**111B**) after the compression of the preceding portion of methane in it, is pumped back to the sea (as seawater **80A**) by pump **107** emptying pipe coil **111** from the most part of its content. However, coil **111** is not pumped out completely; a small sea water layer **80** screened with liquid hydrocarbon layer **70** remains in it.

[00153] In the course of gas field operation, intrastratal gas pressure in it gradually decreases, and, respectively, the gas recovery starts dropping. At this second stage of sea gas field development, intrastratal pressure may be maintained at the required level to assure continuous and stable gas recovery by direct sea water discharge into underwater gas field (as seawater **80B**) through underwater hydraulic turbine **109** mounted at the head of pressure well **23** instead of pumping the evacuated sea water out of coils **111** by pump **107**. A filtering box **130** may be positioned at the input of the injection facility to prevent contamination on the blades of hydraulic turbine **109**. Electric energy generated by a turbogenerator **131** may be used as an additional source of energy and compensate for some of the operational energy. Advantageously, such energy generation recovers some of the energy and makes the illustrated process more profitable. The gas field may be flooded in a controllable mode, and therefore, the volume of sea water fed from coils **111** to hydraulic turbine **109** may be recorded every second by respective telemetric measuring equipment in a control unit **140**, located e.g., on platform **20**. Seawater discharge and pumping rates may be controlled by a remotely controlled stop valve **129**, which may be likewise controlled by control unit **140**.

[00154] As a result of smooth evacuation of seawater **80**, the sea water level in coils **111** decreases gradually, and the hollow helical space above liquid hydrocarbon layer **70** is filled with the next portion of freshly produces natural gas precooled by sea water in heat exchanger **104** to 5-7°C. To compress the next portion of natural gas, hydrostatic pressure of the overlying sea water column is used. For that, a remotely controlled adjustable stopcock valve **132**, mounted at the basis of coil **111**, is slightly opened. As a result, sea water starts entering from below into coil **111** (filled with gas **90** that was sucked in during the seawater evacuation in the former stage). Seawater **80** enter vessel **111** in a helically swirling flow that gradually pressurizes and compresses the natural gas in the seawater-free space. The final pressure of the gaseous medium (**90A**) in this hydraulic compressor is determined by the difference between geodetic marks of the top of hydrocarbon screening layer **70** that covers seawater **80** in underwater coil **111** and the sea level. Hence, with increasing depth of underwater production, the maximum possible pressure of gas compression in coil **111** steadily grows, too. For example, if the sea level exceeds the geodetic mark of the surface of hydrocarbon layer **70** of sea water column in coil **111** by 1000 meters, then the pressure of gas medium compressed in vessel **111** equilibrates this depth and is hence equivalent to $1.03 \cdot 1000 = 1030$ meters of fresh water column (the density of cold sea water depends on its temperature and salinity, but on the average equals 1.03 g/cm^3) or $1030 \cdot 9806.65 = 10100849$ Pa, i.e., 10.1 MPa. It is noted that in order to condense methane, it is not obligatory to compress it to such a high pressure (the critical pressure of methane is much lower – 4.64 MPa). The main condition of its transition into liquid state is the necessity to cool it down to the temperature below the critical one (–82.5°C).

[00155] After compression, the compressed gas may be condensed using an external cryogenic cold-carrier **50**, which has a boiling point below –82.5°C. For example, ethylene C_2H_4 can be used as such low-boiling liquid. The thermodynamic properties of cryogenic liquid **50** are selected such that its normal boiling point at the atmospheric pressure is –103.7°C, i.e., 21.2°C below the condensation temperature of methane (as the main component of natural gas **90**) compressed up to its critical pressure. Meanwhile, the critical temperature of ethylene liquefaction is positive and amounts to 9.3°C, i.e., 5-6°C above the sea water temperature over the most part of the world ocean starting from depths of 100 meters and more. In general, liquid coolant **51** may be selected to have a boiling point at atmospheric pressure which is lower than a condensation temperature of compressed natural gas **90A** and a critical condensation temperature of pressurized coolant **50A** which is higher than a temperature of ambient seawater. Therefore, ethylene may be used as coolant **50** that enables methane liquefaction as well as consecutive condensation in seawater temperatures. Such a system uses the free-of-charge cooling potential of the sea water of the world ocean having the all-the-year-round temperature of the deep-sea zone on the order of 2-4°C. Hence, ethylene **50** compressed to the pressure above the critical one (5.11 MPa) can be transferred from gaseous into liquid state in underwater conditions at the expense of heat exchange with the surrounding sea water only. Therefore, liquid ethylene is used in the present case as a non-limiting example for low-boiling cryogenic liquid **50** for methane liquefaction.

[00156] Prior to cooling by coolant **50**, natural gas **90** may be alternately compressed in coils **111** to the pressure of at least 4.64 MPa, preliminarily cooled in refrigerator **134** laved with cold sea water (temperature 2-4°C) by propeller **135**. The pressure of natural gas compression may be preset beforehand according to the adjustment of check valves **133** operation at a certain threshold value. The compressed methane **90A** cooled in this way to the temperature 5-6°C is fed to the first stage of artificial cooling realized in recuperative heat exchanger **116**, in which the last residues of artificial cold removed by boiling ethylene **50** from the natural gas condensation system are transferred to the former. Methane condensation at the temperature below -82.5°C occurs in cold-exchanger **117**, into which liquid ethylene **51** (boiling in normal conditions at the temperature -103.7°C) is fed, after being throttled in adjustable valve **118**.

[00157] The ready product, liquefied natural gas **91**, may be sent to storage **92** in an underwater depot, wherefrom it may be shipped to consumers by special sea transport or delivered in liquid state to the coast by an underwater pipeline.

[00158] Ethylene that passed from the liquid (**51**) to gaseous (**50**) state at the temperature 103.7°C is fed from cold-exchanger **117** to transfer last residues of its artificial cold to a fresh flow of compressed natural gas **90A**. After that, ethylene vapors are fed to the system of liquefaction of cryogenic fluid for compression (in unit **110B**) and condensation (in unit **115B**). For this purpose, gaseous ethylene **50** leaving recuperative heat exchanger **116** is sucked into one of pipe coils **111** in pressurizing unit **110B** operating, just as coils **111** in pressurizing unit **110A**, in antiphase with respect to one another.

[00159] In vessels **111**, sucking-in occurs owing to the discharge, in the course of emptying, of most part of seawater **80** pumped back into the sea by pump **107** (at the first stage of sea gas field development), or by a direct sea water discharge (alternately from each coil **111**) into the gas pool through hydraulic turbine **109** with a simultaneous electric energy production by turbogenerator **131** (at the second stage of the sea gas field development). Similarly to the structure of the contents of coils **111** in unit **110A**, the helical sea water column **80** in coils **111** is isolated from natural gas by a layer of liquid hexane **70B**, which prevents water vapor penetration into the medium under compression. Water immiscible liquids **70A** and **70B** in units **110A**, **110B** may be similar or different from each other. For example, liquid **70B** may be a hydrocarbon mixture that is more adapted to separate ethylene from seawater, while liquid **70A** may be a hydrocarbon mixture that is more adapted to separate natural gas from seawater. After the intake of gaseous ethylene into the helical space of one of coils **111** (in unit **110B**), the subsequent compression of the gas therein is realized just as in coils **111** (in unit **110A**) – by alternate opening of cocks **122** fitted with drives with remote control. As a result, sea water surrounding such system starts replenishing the non-discharged two-layer column of the liquid medium. As a result (due to a steady growth of the level of the content of each coil **111**), the pressure of ethylene vapor above the surface of hexane layer **70B** starts gradually growing and reaches the level required for its liquefaction at positive temperatures of the surroundings – at least 5.11 MPa. After the actuation (e.g., owing to the overshoot of the established threshold value of the compression pressure) of one of check valves **123**, compressed ethylene **50A** leaves the compressing system and is fed for pre-cooling into refrigerator **124** laved with cold sea water by propeller **125**.

[00160] Compressed ethylene **50A** pre-cooled in this way is then fed to a deep-water condenser **126** installed at a lower level than refrigerator **124**, since the sea water temperature monotonically decreases with growing sea depth. Since the sea water pumped by propeller **127** through condenser **216** has a lower temperature (2-4°C) than that of the condensation of ethylene (9.3°C), which is compressed to the pressure exceeding the critical one, vapors of this organic substance are transformed from the gaseous into the liquid state.

[00161] The obtained cryogenic liquid **51** in the re-condensed form is then fed again for throttling into controlled valve **118**, and after the pressure drop therein down to the atmospheric one, is used again as cold-carrier boiling at the temperature 103.7°C for methane liquefaction in cold-exchanger **117**. Thus, the cycle of the maintenance of methane liquefaction process by a cryogenic liquid is practically completely closed, and at proper production standards, it is not practically consumed in such a closed circulation loop.

[00162] Advantageously, disclosed methods and systems, as compared to known methods of sea gas fields development, provides a number of essential technical and economic advantages. First of all, they allow supplying natural gas produced in a sea field to the consumers right away in the liquid form. This advantage allows the development of the most part of sea gas field explored by the present moment, which are located at the distance of hundreds and thousands of kilometers from the coast. Note that the fact that one cubic meter of liquefied natural gas is 625 times heavier than one cubic meter of gaseous methane is the main reason of low cost efficiency of transportation of such fuel over large distances and of the absence of stimulus for the development of sea gas fields very far from land.

[00163] As for the competitiveness of the disclosed methods and systems with respect to known methods of methane liquefaction used at the development of gas fields on land, natural gas compression in the helical space of pipe coils is an incomparably less cyclic process than the use of piston compressors, since geometrical volumes of working cylinders of such facilities can differ hundreds-fold and thousands-fold (at the internal diameter of the helical space measured in meters, spiral winding radius in tens of meters, and total spiral height in hundreds of meters). Thus, not only a drastic increase in the productivity of the compression process is ensured, but a much higher level of its power perfection is achieved, since the intensification of piston compressors operation is connected with heat generation growth and, thus, a decrease in the share of electric power transformed into an increase in the compressed gas pressure. Hence, the disclosed methods and systems are much more scalable than piston based systems and their advantages increase with increasing system size.

[00164] A simultaneous electric power generation at the emptying of the main part of the helical working space of coils at the second stage of sea gas field development (when the sea water obtained at the emptying of the hydraulic system of methane and ethylene compression is discharged through the hydroturbine with a turbogenerator into the gas pool for maintaining the intrastratal pressure in it at the necessary level) increases the profits of natural gas production from the sea bottom by the method of the invention.

[00165] An additional advantage of the invention is that with growing sea depth, the cost efficiency of the underwater methane liquefaction used in the work of such gas fields only increases, which can be attributed to the growth of sea water hydrostatic pressure and a steady decrease of its temperature with the approach to the sea bottom.

[00166] These advantages also imply that the environmental footprint of the disclosed invention is much smaller than of current technologies. Not only is the energy efficiency of the process itself is higher, but the energy and space requirements for gas transportation and liquefaction in land are spared.

[00167] Embodiments of the present invention enable a complex usage of the initial energy mineral, deepen its processing, reduce power intensity of the production of artificial liquid fuel, reduce investments for the erection of coal liquefaction facility and weaken harmful effect of the technological process on the environment by its realization in underground conditions. In certain embodiments, before the hydrogenation, the processing of the initial crushed mineral (in particular, coal) is started with preliminary separation of the combustible mineral from waste rock combined with its vertical transportation – floating of the mineral from the mining site to the site of its further processing in a vertical column filled with water-salt solution with the density exceeding that of coal. Principal ingredients for the preparation of the water-salt medium are ionogenic inorganic compounds that not only possess a high enough water solubility (which allows the produced water solutions to reach the density sufficient for coal floating), but also are highly active catalysts of the subsequent hydrogenation process.

[00168] **Figure 10A** is a schematic illustration of a non-limiting example for a combustible material processing system **500**, according to some embodiments of the invention; **Figure 10B** is a high level schematic illustration of subsystems in combustible material processing system **500**, according to some embodiments of the invention; **Figure 11A** is a high level schematic flowchart illustrating central stages of a method **600** of separating and hydrogenating combustible material, according to some embodiments of the invention; and **Figure 11B** is a high level schematic flowchart illustrating further stages of method **600** of separating and hydrogenating combustible material, according to some embodiments of the invention.

[00169] Method **600** may comprise preparing a water-salt medium **480** to have a specified density (stage **602**) and using catalytic salts (stage **604**). The preparation of water-salt medium **480**, which is intended for floating, grinding and step-by-step beneficiation of the original mineral by dissolving in water one or several mineral salts catalyzing the hydrogenation process. The preparation brings solution **480** to the density intermediate between those of combustible mineral **490** and contaminating mineral admixtures, i.e., waste rock **489**.

[00170] Method **600** may further comprise preparing and delivering raw material **490** (stage **606**), e.g., by preliminary dry preparation of freshly produced original raw material by size for charging it into a column of heavy water-salt medium for separating, in the course of the beneficiation-and-transportation process, a product refined with respect to its combustible component. Raw combustible material **490** is thus turned into prepared combustible material **490A**.

[00171] Method **200** may further comprise separating the combustible material from waste rock **489** gravitationally in aqueous salt solution **480** selected to have a density which is intermediate between a density of combustible material **490A** and a density of the waste rock (stage **610**). This stage may be carried out in a floating subsystem **610A** which comprises a vertical floating container **505** as described below. Method **600** may comprise separating the combustible material by floating and sinking waste rock (stage **612**) by delivery of, e.g., coal, with its simultaneous release from the greatest part of waste rock, from the production site to the processing site by vertical floating in a water-salt medium with the density exceeding that of the coaly substance.

[00172] Waste rock **489** may be sunk in water-salt medium **480** and then be squeezed from the liquid phase, rinsed with water and ground, with simultaneous capturing of methane released into the gaseous phase in the course of the size reduction. After that the waste material may be arranged in the worked-out space. Method **600** may further comprise separating hydrocarbon gas and regeneration of the solution from the waste rock (stage **620**). This stage may be carried out in sank waste treatment subsystem **620A** and may comprise removal of sunk waste rock **489** from the water-salt medium, hydro-mechanically squeezing and cleaning the waste rock with water (together with all other solid wastes of coal-liquefaction industry) from the liquid phase residues and further grinding of the cleaned material, with simultaneous capturing of the released methane and operative arrangement of all solid waste of the technological process in the worked-out space. Hence, method **600** may further comprise removing and processing the sunk waste rock (stage **622**); separating and reusing the water-salt medium from the waste rock (stage **624**) and capturing methane from the processed waste rock (stage **626**).

[00173] In certain embodiments, method **600** further comprises grinding (the first stage of refinement) of the floated (and beneficiated at the same time) initial mineral is carried out at the ambient temperature in the same solution (saturated with ingredients catalyzing the hydrogenation process), which has a density that exceeds that of the combustible mineral, but is lower than that of the waste rock. The successive reduction of the processed material size may be accompanied by a preliminary spatial separation of minerals composing the initial mineral. The light fraction enriched by its combustible component floats up out of the zone of grinding bodies, while the heavy material consisting mainly of waste minerals sinks in the water-salt medium flooding the drum mill. During grinding, methane may be released out of the ground material into the gaseous phase, be captured and sent to catalytic conversion with water vapor for obtaining hydrogen used in the process of hydrogenation (see below).

[00174] Method **600** may further comprise successively reducing particle size of the separated combustible material in the solution and removing residual waste rock and gas therefrom (stage **630**), e.g., in a milling and separation subsystem **630A**. The first (cold) stage of grinding the floating lumps of coal may be carried out with simultaneous concentration of the ground material realized at the ambient temperature in the same water-salt solution **480** saturated up to the density value that is exactly intermediate between those of the combustible and incombustible mineral components, with simultaneous capturing of methane released, in the course of grinding, into the gaseous phase, and subsequent separate outlet of light (crude concentrate) and heavy (final tailings) of beneficiation products out of the process. In certain embodiments, method **600** further comprises any of the stages: grinding (in a first, cold stage) the floating combustible material in the salt solution (stage **632**); capturing gas and separating light and heavy phases (stage **634**); and removing additional waste rock (stage **636**).

[00175] In certain embodiments, before the second stage of grinding, a suspension of the light product (crude concentrate) of the first (cold) stage of grinding and beneficiation may be heated and additionally ground under moderate heating, together with its further separation. Then, the produced technological flow containing a solid phase, even more completely beneficiated with the coaly substance, is heated to a higher temperature, additionally ground to extra-fine state and, finally, precisely separated from the residues of visible mineral admixtures in a hot regime in a powerful centrifugal field. Method **600** may further comprise heating and grinding the combustible material of reduced particle size to yield a paste of purified combustible material (stage **640**), e.g., in a heating and further milling subsystem **640A**.

[00176] Method **600** may further comprise heating of the suspension of the light product of the first concentration stage to a moderate temperature; and carrying out a second (warm) stage of crude concentrate grinding and beneficiation in a heated aqueous solution with a simultaneous (as at the first stage of grinding) discharge of methane released during the decrease of the ground material size, and the subsequent separate output of the light product, which is fed after that to the last stage of material preparation by its size and composition before its liquefaction, and of the heavy product returned, respectively, to the first (cold) stage of the process for additional grinding. Method **600** may further comprise final heating of the beneficiated product of the warm stage of coal processing to a higher temperature, which is somewhat lower than the water-salt solution boiling point. In certain embodiments, method **600** further comprises any of the stages: heating the separated combustible material (stage **641**); grinding (second, moderately heated phase) the heated combustible material (stage **642**); separating light and heavy phases and reprocessing bulky material (stage **643**) and heating the separated combustible material to higher temperatures (below boiling) (stage **644**).

[00177] Method **600** may further comprise further heating, reducing viscosity, grinding and centrifugal separation in a heated grinding subsystem **640B**. Method **600** may comprise a third (hot) stage of grinding with a subsequent final precise beneficiation of extra-fine coal in a strong centrifugal field in the same water-salt medium, but in hot separation mode, comprising grinding (third, hotter phase) the heated combustible material (stage **645**) and separating light and heavy phases and reprocessing bulky material (stage **646**).

[00178] Method **600** may further comprise mixing the obtained hot extra-pure coal concentrate with hot paste-former (at that, water from water-salt solution impregnating the coal concentrate starts boiling). Then the obtained paste may be diluted to a mobile consistence, the solid phase of the formed coal-oil mixture is levigated to a colloidal particles size and fed by a vertical rotating hollow shaft (ending with a T-shape reactive turbine – Segner wheel), which may be installed in the vertical well, to underground hydrogenation in a blind pit equipped with tangential introduction of hydrogen. This stage may be carried out in deep squeeze and paste formation subsystem **640C**, in which hydromechanical squeezing of the final extra-pure coal concentrate from water-salt medium is carried out, with further mixing with hot paste-forming substance and simultaneous removal of excessive humidity from the squeezed cake by its boiling, and additional dilution of the obtained coal/oil mixture to the desired consistency with an organic solvent. In certain embodiments, method **600** further comprise further heating the separated combustible material (stage **647**); purifying the heated combustible material by centrifugation (stage **648**) and fluidizing the paste (stage **650**), e.g., diluting the paste with an organic solvent (stage **651**), in a paste fluidizing subsystem **650A**. Method **600** may further comprise additional levigation of the solid phase of the coal/oil mixture prepared for hydrogenation to the colloidal size, e.g., levigation to colloidal size as preparation for hydrogenation (stage **653**).

[00179] Method **600** may further comprise hydrogenating the diluted paste (stage **660**), e.g., in a hydrogenation subsystem **660A**. In certain embodiments, method **600** comprises recuperative heating of coal/oil mixture (by hot artificial petroleum rising in the opposite direction) and its subsequent feed into the hydrogenation process by a rotating vertical hollow shaft installed in a vertical well cut into a hermetic blind pit, while hydrogen is tangentially fed, at the same time, at several heights into the lower part of the blind pit; and hot catalytic hydrogenation of the coaly substance of solid phase of the coal/oil mixture by its interaction with hydrogen under elevated pressure at high temperature in the presence of a catalyst realized in a hermetic blind pit in underground conditions. In certain embodiments, method **200** further comprises any of the stages: applying hot catalytic hydrogenation to the levigated diluted paste of combustible material (stage **661**); introducing hydrogen under elevated pressure and high temperature in the presence of a catalyst realized in a hermetic blind pit in underground conditions (stage **662**); introducing hydrogen at different regions of the hydrogenation column (stage **663**) and carrying out the hydrogenation e.g., in association with a Segner turbine (stage **665**).

[00180] Method **600** may further comprise final cleaning and processing of hydrogenation residues (stage **670**), e.g., in a residue purification and separation subsystem **620B**, extraction of residual hydrocarbons and working liquids and processing waste material. Method **600** may comprise introducing liquid hydrogenate to rise from the blind pit to be released from gases dissolved in it by feeding the artificial petroleum discharged to the ground surface (through the annular gap between the rotating hollow shaft and vertical well connected with the blind pit) into a hollow volume, with simultaneous recuperative heat exchange between technological counter-flows between these heights. Hydrogenate rising from the blind pit through an annular gap between the rotating shaft and vertical well head may be released from dissolved hydrocarbon gases and separated into artificial petroleum and non-liquefied solid residue. The latter may be washed with organic solvent, dried and mixed with dewatered heavy product of the first grinding stage. The mixture of inert minerals free from organic admixtures may be rinsed with water and removed from the production cycle. Rinsing water remaining after washing this finely disperse waste, as well as that remaining after washing lump waste rock (which sank at the coal floating in water-salt medium), are evaporated to their initial density. The regenerated water-salt solution may be returned to the head of the process. In certain embodiments, method **600** further comprises any of the stages: allowing the hydrogenation product to rise from the blind pit (stage **666**); heating the reacting material by heat exchange with the hydrogenation product (stage **667**); and recirculating non-condensed residues of unreacted hydrogen back to the hydrogenation system (stage **668**).

[00181] Method **600** may further comprise separating a vapor/gas mixture from hydrocarbon liquid phase at the vertical well head with subsequent light hydrogenate condensation and recirculation of non-condensed residues of unreacted hydrogen back to the hydrogenation system; releasing liquid hydrogenate from the remaining non-liquefied solid inert admixtures and its feed for further processing to a petroleum refinery; cleaning of the solid residue extracted from the heavy hydrogenate from the impregnating hydrocarbon liquid phase by an organic solvent and its further drying and removal out of the process; mixing of dry solid hydrogenation residue with dehydrated heavy product of the first stage of the original mineral grinding; cleaning of the final humid mechanical mixture of inert incombustible minerals from the catalyst residues with fresh water, and a subsequent squeezing of the moist waste product from an excessive liquid phase; evaporation of rinse water remaining after washing the mixture of solid waste products until the evaporated solution reaches the initial density (intermediate between those of the combustible mineral and mineral admixtures), and returning the regenerated water-mineral medium to the head of the process. In certain embodiments, method **600** further comprises any of the stages: separating the hydrogenation product into different phases (stage **672**); removing residues from the product (stage **674**); and further processing and refining the product (stage **675**).

[00182] In certain embodiments, heavy waste products of the second and third stages of gravity beneficiation may be squeezed from excessive liquid phase and returned to wet grinding in the cycle of the first (cold) concentration stage. In the capacity of mineral salts catalyzing the hydrogenation process, only those water-soluble chemical compounds with a high catalytic activity, which are high soluble in water, allow preparing solutions on their basis, which have a density that is sufficient for floating combustible components of the initial rock mass, are used, and not just ionogenic inorganic substances facilitating the interaction of carbon-containing component of the combustible mineral with hydrogen. These water-soluble compounds may be selected to catalyze the hydrogenation process as well as to form aqueous solutions with the density intermediate between those of combustible mineral and waste rock are, e.g., certain mineral salts with high enough water solubility, such as zinc or tin chlorides or bromides, ammonium paramolybdates and tetramolybdates or iron sulfates, or else their mixtures. Water solubility of hydrogenation catalysts of this type is quite sufficient for preparing aqueous solutions with the density needed for floating of only combustible components of the original rock mass. For instance, 60%-solution of ferric iron sulfate $Fe_2(SO_4)_3$ at the temperature 17.5°C has the density 1.798 g/cm^3, while the density of coal does not exceed, as a rule, the values of 1.319-1.546 g/cm^3. In other words, it is not necessary to use solutions highly saturated with the mineral component for coal floating. More dilute water-salt media are also applicable, for example, 40%-solution of the same ferric iron sulfate in water (its density at 17.5°C equals 1.449 g/cm^3). Preparation of such solutions on the basis of water-soluble molybdenum-containing salts, e.g., ammonium paramolybdate or tetramolybdate, and introduction of other microadditives into the final mixture allow the water-salt medium not only to achieve the density required for coal floating, but also to increase catalytic activity of the formed compositions. In certain embodiments, the density of all principal rock-forming minerals (argillite, siltstone, limestone, quartzite, sandstone, anhydrite, granodiorite, feldspar, montmorillonite and other alumosilicates) is much higher (about 2.376-2.887g/cm^3), which predetermines the absence of any possibility of their floating together with coal in such a relatively light (for them) liquid.

[00183] The paste-forming substance may comprise various compositions, e.g., products of petroleum processing, by-product coking or fine organic synthesis can be used, which contain thermally unstable organic substances (primarily, of aromatic series) that can serve as atomic hydrogen donors at their heating, e.g., tetralin mixture with anthracene oil diluted afterwards with isopropyl alcohol. However, not only paste-forming substance components can supply atomic hydrogen in the method of the invention, but also mineral salts used as the basis for the preparation (or introduced as impurity ingredients) of water-salt solutions for coal floating. For example, if a solution of a mineral salt as potassium formate highly soluble in water is used as the heavy liquid (when approaching the saturation state, its density reaches 1.570 g/cm^3 and more), this inorganic substance that has arrived to the hydrogenation stage together with the final extra-pure coal concentrate, thermally decomposes at heating above 360°C into potassium oxalate and hydrogen. The latter, at the moment of its appearance, exists in the atomic form and is a very strong reducer drastically facilitating further bonding of hydrogen atoms to carbon atoms: $2HCOOK = (COOK)_2 + 2H^+$. Hence, certain embodiments utilize a unique combination of properties as found in potassium formate, namely that the density of HCOOK solution in water is greater than the density of coal, whereas upon heating this salt it decomposes with formation of atomic hydrogen, which leads to a sharp acceleration of the hydrogenation process.

[00184] Besides, in contrast to known solutions in the field of artificial liquid fuel production using dry methods of the initial mineral transportation from the mining face to the liquefaction site and conventional grinding processes, the delivery of newly-produced coal to its processing site by vertical floating with further additional wet grinding in the same water-mineral medium, whose density is intermediate between those of the combustible mineral and its incombustible components, not only combines the process of delivery (by the shortest route) from the mining site to the site of preparation for hydrogenation (simultaneously releasing it from the most part of waste rock), but also totally isolates the coaly substance from contact with air oxygen.

[00185] As a result, the absence of oxygen access to the coal surface leads to the prevention of its endogenous (invisible) oxidation, which negatively affects the completeness and velocity of the combustible mineral liquefaction (not to speak about hydrogen over-expenditure). Meanwhile, step-by-step grinding of the coal preliminarily beneficiated in the process of floating in the same water-salt solution, which precedes the hydrogenation stage, leads to automatic slipping of fragments of combustible mineral (as they get released from accretions with waste rock) from the hits of grinding bodies and, thus, to a decrease in ball load of the mills. In combination with the possibility to obtain artificial liquid fuel in underground conditions, with a spontaneous recuperation of gratuitous heat of the Earth interior for primary heating of the participants of hydrogenation interaction (due to elevated temperatures characteristic of bearing strata at large depth) and to reject high-lift pumps (which are the main consumers of electric power at coal liquefaction in ground-surface conditions) for introducing the original coal-oil paste into the hydrogenation process, the invention ensures a higher level of energy perfection of the processing of the produced solid fuel into artificial petroleum in comparison with known ground-surface technologies of obtaining synthetic liquid fuel from various combustible minerals.

[00186] Advantageously, the total decrease of the volume of technological flow fed to the hydrogenation stage, which must be heated to the reaction temperature, and the reduction of power consumption connected with further separation of liquid products from solid inert admixtures removed from the liquefaction process by the artificial petroleum, may ensure both an additional significant reduction of energy consumption for producing artificial liquid fuel according to the invention, and a radical weakening of harmful influence of the disclosed technological process on natural environment. Besides, capturing of methane and other combustible gases may accompany all the processes of size reduction and ensure complex usage of valuable power resources contained in the original mineral. Thus, all the features of the present invention may be interconnected, and their combination may allow the achievement of the above mentioned advantages.

Example

[00187] As a non-limiting example, the following detailed system plan illustrates realization embodiments of the invention described above. In this non-limiting example, coal may be processed as the combustible material. All values mentioned below are non-limiting examples and may be modified and adapted according to different types of combustible material, different configuration of the processing units and fluids.

[00188] Floating subsystem **610A** may be arranged to gravitationally separate the combustible material from waste rock in an aqueous salt solution selected to have a density which is intermediate between a density of the combustible material and a density of the waste rock.

[00189] Freshly produced lump coal or other combustible material **490** from the mining face is subjected to preliminary screening by size on sieve **501**. Lumps of the initial mineral that have passed through the sieve are fed to further processing, while the oversize material is crushed in crusher **502** and then added to the undersize through-product of screening. Both sieve **501** and crusher **502** are enclosed into hermetic casings in rarefaction created in the system of methane capturing (not shown). Raw combustible material **490** is thus turned into prepared combustible material **490A**.

[00190] Combustible material **490A** prepared by size in this way (the size of the biggest lump of crushed rock mass not exceeding a half of the diameter of vertical pipeline **505** for coal floating) is charged into one of legs **503** of the locking mechanism of the initial feeding of the system of hydrostatic hoist of coal liquefaction facility.

[00191] Then, the charged material is pressurized in the chamber by rotating gate **504** into right-hand position pressed to vertical column **505**, and flooded (e.g., by opening lateral taps in the upper and lower parts of column **505**) with aqueous solution **480** of mineral salt, which may be used to float combustible material **490A** and sink waste rock **489**, and may also operate as a catalyst for the subsequent hydrogenation process. The air pressed out of this hermetic volume is released through air valves (not shown).

[00192] Examples for aqueous salt solution may comprise 40%-solution of zinc chloride in water with the density 1.423 g/cm^3 (at 25°C) with ammonium paramolybdate admixture is used as water-salt medium for the realization of the technological process. However, other mineral salts and their various mixtures, such as nanoaqueous ferric iron sulfate $Fe_2(SO_4)_3{\cdot}9H_2O$, ammonium paramolybdate $(NH_4)_6Mo_7O_{24}{\cdot}4H_2O$, ammonium tetramolybdate $(NH_4)_2{\cdot}4MoO_3{\cdot}2H_2O$, iron vitriol $FeSO_4{\cdot}7H_2O$, bivalent tin chloride $SnCl_2$, a mixture of nanoaqueous ferric iron sulfate $Fe_2(SO_4)_3{\cdot}9H_2O$ with penta-aqueous chloride of quadrivalent tin $SnCl_4{\cdot}5H_2O$ (used in a 3:1 weight ratio), zinc bromide, etc., can be used as such inorganic compound possessing the set of properties necessary for the realization of the process of the invention.

[00193] In certain embodiments, aqueous salt solution **480** may also comprise oxidized forms of various metals of variable valency, such as iron, nickel, cobalt, molybdenum, tin, aluminum, silicon oxides, as well as tungsten, molybdenum, sodium, potassium, nickel and iron sulfides with the addition of elementary sulfur, and various multi-component compositions on their basis, as well as sulfates and halides of certain metals or ammonium salts of isopolimolybdenum and thiomolybdenum acids and other chemical compounds which are capable to accelerate the hydrogenation process or to deliver atomic hydrogen and hence be used as catalysts of the combustible minerals liquefaction described below.

[00194] Densities of aqueous solutions **480** of the mineral salts catalyzing the process of the coaly substance hydrogenation exceed the density of the respective kinds of solid fuel, which predetermines the possibility of the combustible mineral floating in it. Meanwhile, waste rock **489**, which is heavier than coal, sinks in medium **480**, which allows combining vertical delivery of coal to the site of its further processing with simultaneous preliminary beneficiation.

[00195] Then, smoothly turning the central gate **504** into the right-hand position, the internal volume of left leg **503** is combined with the contents of vertical column **505** into a vertical column of water-salt medium with the density exceeding that of coal. It leads to the floating of the next portion of coal **490A** from the mine to the ground surface, while waste rock **489**, which is heavier than zinc chloride solution **480**, sinks in liquid **480** and thickens at the discharging nipple of the charging facility.

[00196] Combustible material **490A** such as coal floats in water-salt solution **480** and is accumulated in the form of a loose cap in the upper (broadening) part of column **505**, wherefrom it is fed to the first stage of grinding realized in the same water-salt medium flooding ball mill **506**, whereas the waste rock sunk in liquid4 **80** is discharged through the locking system into thickener **507**. These are the first units of milling subsystem **630A** arranged to successively reduce a particle size of separated combustible material **490A** in solution **480** and to remove residual waste rock and gas therefrom (see below).

[00197] Waste material **489** is treated in sank waste treatment subsystem **620A**, e.g., thickened in a thickener **507** and squeezed from the liquid in filtering centrifuge **508** and then discharged into band vacuum filter **509**, where it is squeezed (together with other solid wastes of the process, see below) from water-salt liquid phase, rinsed with fresh water in the countercurrent mode and fed to the grinding in hermetic mill **510**. In the course of outcropping of new surfaces of the ground material, methane released into the gaseous phase is sucked out of the mill. Waste material **489**, which is ground and released from methane, is arranged in the worked-out space. This prevents the development of geomechanical processes of movement of the overlying strata of rocks, which entail an irreparable damage to all ground-surface objects located at the territory undermined by underground mining, from the consequences of the ground surface subsidence. Meanwhile, aqueous solution **480A** of zinc chloride clarified from the waste rock is returned by piston pump **510** to the system of hydrostatic coal hoisting system.

[00198] In milling subsystem **630A**, further grinding of combustible material **490B** is carried out. Combustible material **490B** is the floated material **490A** which was preliminarily released from the most part of waste rock **489** in the process of its floating up (as combustible material **490A**). The further grinding is accomplished in ball mill **506** in the same water-salt medium **480**. While coal is released out of its accretions with waste rock by the milling, fragments of the coaly substance are not subjected to further destruction and remain afloat on the surface of liquid medium **480**, while all other components of the original raw material are submerges again into the zone of the impact of milling bodies. As a result, with crushing of floated combustible material **490A** by steel balls continuously rolling in the drum of mill **506**, fragments of pure coil appearing in the course of the milling process, irrespective of the extent of their crushing, float up to the surface of liquid **480**, automatically avoiding, in this way, energy over-expenditure for their additional over-crushing, which entails the efficiency of subsequent separation and growth of the beneficiation products humidity.

[00199] Additional methane may be discharged into the gaseous phase (like other gaseous hydrocarbons), which is practically water-insoluble. The gases bubble through the layer of water-salt solution **480** (within mill **506**) and then gets into the system for capturing it, wherefrom it is fed to catalytic conversion with water vapor in order to obtain hydrogen needed for coal hydrogenation. The excess of this energy carrier is sold to exterior consumers as gaseous fuel.

[00200] The discharge of mill **506** is delivered to sump **512** equipped with a mixer, wherefrom it is fed by pump **513** to hydrocyclone **514**, where coal is more intensely (as compared with mill **506**) separated from incombustible inert admixtures, which are much heavier minerals forming the part of the original energy mineral. The light product (crude coal concentrate) of the first separation cycle coming out of the upper axial nipple of the cylindrical part of hydrocyclone **514**, is delivered to vapor-heated container **515** (heated by vapor **491A**) equipped with a mixer, being part a heating and further milling subsystem **640A**. As a result of heating, the density of the liquid phase of the suspension drops e.g., from 1.423 (at 25°C) to 1.403 g/cm^3 (at 50°C). The lowered density improves the separation capability of solution **480** as it can separate waste rock which is closer in density to the combustible material.

[00201] To achieve a more complete opening of accretions, the material flow may be fed to the second stage of grinding. This process is realized in a moderately warm mode in a drum ball mill **516**, which is also connected by its end-face with methane collector, but, in contrast to mill **506**, is covered with a thick layer of thermal insulation. The heavy waste product of the first grinding stage coming out of the head of conical part of hydrocyclone **514** is hydromechanically squeezed from liquid phase excess on a filtering centrifuge **517** and supplied to mixer **518** for mixing with the solid residue extracted in the tail of the technological system of coal liquefaction from heavy hydrogenate. The denser part of the mixture separated by filtering centrifuge **517** is returned to the first separation cycle for mixing with the product for further grinding, which comes out of mill **506**. The discharge flow from mill **516** (similarly to the discharge of mill **506**) is also fed, from thermally insulated sump **519** equipped with a mixer, to separation realized in hydrocyclone **521** covered with thermal insulation (to avoid the return of the liquid phase density to its original value, at which the first stage of grinding and separation was realized).

[00202] Heated grinding subsystem **640B** is arranged to heat and grind the combustible material of reduced particle size (**490C**) to yield a paste (**490E**) of purified combustible material. The light fraction discharged from the upper axial nipple of the cylindrical part of hydrocyclone **521** is fed to container **522** equipped with a mixer and heated by vapor **491B**, where the technological flow is heated to 90-95°C, which leads to a further decrease in the density of zinc chloride solution in water from 1.403 to 1.354 g/cm^3 and a drop of its viscosity, respectively, from 2.469 (25°C) and 1.454 (50°C) to 0.727 centipoise (note that it is much below the fresh water viscosity). Further grinding of this crude coal concentrate is accomplished in vibromill (vibratory grinding mill) **523**, which is also thermally insulated.

[00203] After that, the final precision beneficiation of coal is realized in a strong centrifugal field of settling centrifuge **524** covered with thermal insulation. The high efficiency of the centrifugal separation in a strong centrifugal field of settling centrifuge **524** is due not only to the fact that the stratification of minerals being separated occurs in a heavy medium with anomalously low viscosity. In contrast to separation in hydrocyclones **514** and **521**, the stratification of the original mixture of minerals in fast settling centrifuge **524** is realized in a motionless liquid, which is at rest with respect to the rotating vessel it is in, with which it rotates around the horizontal axis, and not in a turbulent rotating flow. The heavy, but non-viscous liquid, which is at rest with respect to the rotor of centrifuge **524**, rotates inside the centrifugal separator at the same velocity as the bucket rotating around its longitudinal horizontal axis at a huge angular velocity. As a result, inside the centrifuge rotor, a motionless liquid sleeve in the form of annular solid of rotation arises, and the extra-pure coal concentrate floats up to its internal cylindrical surface. Advantageously, the separation factor can reach values which are much higher than separation values achieved in the conditions of minerals stratification in hydrocyclones (and even more so with respect to static conditions), since rotation velocities of the centrifugal separators reach thousands revolutions per minute. Besides, in any hydocyclone, liquid moves along a trajectory swirling with respect to its motionless wall. This causes additional head loss of the turbulent flow due to a large touch area of rubbing liquid and solid surfaces, not to speak about a considerable erosion of the casing of the separation facility.

[00204] Coaly material of extra-high purity, which is wholly free from visible mineral admixtures and represents the product of the third, precision stage of coal beneficiation (heated grinding subsystem **640B**), is carried out as the light material separated by settling centrifuge **524**. Meanwhile, the discharged cake (heavy material) representing a waste product of centrifugal beneficiation and containing last traces of the combustible substance is returned to the head of the beneficiating part of the process by elevator **525** (equipped with a cooling jacket and a fan for cooling the transported material down to ambient temperature) for mixing with input technological flow entering mill **506** of the first, cold grinding cycle.

[00205] A deep squeeze and paste formation subsystem **640C** carries out the final deep squeezing of the extra-pure product of the third separation stage by delivering the lighter material of settling centrifuge **524** into filtering centrifuge **526**. After that, the obtained transparent hot water-mineral medium is returned by pump **528** from thermally insulated sump **527** to container **522**. Wet coal cake **490D** impregnated with aqueous solution of zinc chloride (**480**) is fed into screw mixer **529** heated by blind vapor **491C** for mixing with a hot (140-190°C) paste-forming substance **470**

comprising, e.g., tetralin (1,2,3,4-tetrahydronaphthalene - $C_{10}H_{12}$) with an admixture of anthracene oil (a fraction of coal-tar resin boiling within the range 270-360°C), and a micro-admixture of elementary sulfur. Screw mixer **529** with paste-forming substance **470** thus turns the wet cake of combustible material **490D** into a combustible material paste **490E**. However, not only paste formation occurs, but additionally, extra-pure coal concentrate **490D** is released from excessive aqueous moisture (boiling at a high temperature, and as a result, screw mixer **529** operates under rarefaction), and final residues of aqueous solution containing mineral salts catalyzing the hydrogenation process with the formation of micro-drops of the catalyst, are emulsified. Water vapors formed in the course of the process are disposed to the condensation.

[00206] A paste fluidizing subsystem **650A** is arranged to fluidize paste **490E**. The consistency of the homogeneous pasty mass **490E** prepared in screw mixer **529** is corrected in mixer **530** by admixing a diluting fluid **460** such as isopropyl alcohol (isopropanol $CH_3CHOHCH_3$), or by mixing with some other organic solvent and delivered to disperser **531**. There, the solid phase of the coal-oil mixture is additionally rubbed in a strong centrifugal field down to the colloidal size, simultaneously emulsifying the catalyst even more finely, to yield fluidized combustible material **490F**. The extra-pure coal concentrate is thereby deeply cleaned from mineral admixtures and rubbed in disperser **531** to an extra-fine state, in the form of easy-to-move hot coal/oil mixture **490F**, which is delivered as a solid stream by guiding nipple **532** submerged into this slush into receiving cone **532** of hydrogenation subsystem **660A**.

[00207] Hydrogenation subsystem **660A** is arranged to hydrogenate fluidized paste **490F**, e.g., in a vertical pipe (**534**) ending below with T-joint (**536**) with oppositely directed nozzles (**537**) forming a reactive turbine – the Segner wheel. In certain embodiments, hydrogenation subsystem **660A** comprises a vertical shaft **534** arranged to receive the fluidized paste and maintain a downwards flow **490F** thereof; a Segner turbine **536** in fluid communication with vertical shaft **534** and arranged to be rotated by flowing fluidized paste **490F** (by releasing fluidized paste **490F** through nozzles **537**); a hydrogenation chamber **538** (also termed blind pit **538** in the following) enclosing a bottom portion of vertical shaft **534** and Segner turbine **536**. Hydrogenation chamber **538** further comprises a heating unit **539** arranged to heat fluidized paste **490F** and **490G** (see below) and a hydrogen supply **540** arranged to introduce hydrogen **450** into fluidized paste **490F** that exits Segner turbine **536**, to hydrogenate the fluidized paste. Hydrogenation subsystem **660A** further comprises a vertical enclosure **535** in fluid communication with hydrogenation chamber **538** and arranged to maintain an upwards flow **490G** of the hydrogenated fluidized paste from hydrogenation chamber

538 while enabling recuperative heat exchange between rising hydrogenated fluidized paste **490G** and downwards flow of fluidized paste **490F**.

[00208] Some embodiments of the invention comprise a hydrogenation unit **260A** comprising: a vertical shaft **534** arranged to receive a fluid combustible material **490F** and maintain a downwards flow thereof; a Segner turbine **536** in fluid communication with vertical shaft **534** and arranged to be rotated by the flowing fluid combustible material; a hydrogenation chamber **538** enclosing a bottom portion of vertical shaft **534** and Segner turbine **538**. Hydrogenation chamber **538** comprises heating unit **539** arranged to heat the fluid combustible material and hydrogen supply **540** arranged to introduce hydrogen into the fluid combustible material that exits Segner turbine **538**, to yield a hydrogenated combustible fluid. Hydrogenation subsystem **260A** further comprises a vertical enclosure **535** in fluid communication with hydrogenation chamber **538** and arranged to maintain upwards flow **490G** of the hydrogenated combustible fluid from hydrogenation chamber **538** while enabling recuperative heat exchange between rising hydrogenated combustible fluid **490G** and downwards flow of fluid combustible material **490F**. It is explicitly noted that hydrogenation unit **260A** may be part of system **500** or may be an independent unit, receiving fluid combustible material from any source and delivering hydrogenated combustible fluid to any further processing facility. In certain embodiments, vertical shaft **534** and vertical enclosure **538** are at least one kilometer long and Segner turbine **538** is in an underground mine for combustible material that is used to generate the fluid combustible material. A more detailed description of hydrogenation unit/ subsystem **660A** is presented below.

[00209] Cone **533** is the upper part of rotating vertical pipe **534** ending below with T-joint **536** with oppositely directed nozzles **537** forming a reactive turbine– the Segner wheel. Thus, the slippery coal/oil mixture **490F** supplied for hydrogenation is, simultaneously, the working medium of the mixing hydromechanic facility. However, some embodiments of the invention may comprise other hydrogenation subsystems **650A**. Rotating vertical pipe **534** supplying this flow for hydrogenation is concentrically inserted into vertical well **535** which ends with blind pit **538** – a vertical excavation protected from inside against rock pressure by a hermetic tub.

[00210] Owing to the reaction of high-pressure jets of mobile hot coal/oil mixture flowing out of these nozzles **537**, the rotation of the entire hollow vertical shaft enclosing column of coal/oil mixture **490F** about thousand and more meters high around its axis is realized. If spinning to even higher angular velocities is needed, the mixer in blind pit **538** can be set to rotation using an additional electric drive. Here, a hydrostatic pressure reaching a hundred atmospheres and more is spontaneously generated in blind pit **538**. Its value depends on the depth of underground mining and the height of the well head above the ground surface. Since modern coal mines have already reached the depth of 1200-1400 meters (the record depth being 2042 meters), and the average level of underground mining around the world is steadily decreasing, even at the depth of 1100-1300 meters, the pressure of a vertical column of the coal-weighted mobile hot slush **490F** reaches, in a natural way, the values on the order of 10-12 MPa at the base of blind pit **538** without external energy consumption. Such relatively high pressure is quite sufficient for highly efficient liquefaction of coaly substance **490F** using a number of highly active catalysts prepared on the basis of water-soluble inorganic compounds (including molybdenum-containing ones, originating, e.g., from solution **480**). Besides, the temperature of enclosing rocks at such depths is not subject to daily or seasonal fluctuations and is elevated in comparison with meteorological conditions in the working zone of coal liquefaction in ground-surface conditions, especially in winter. Although the gratuitous use of the heat of the Earth's interior allows a certain reduction of energy consumption in the described processes, temperatures of about 45-55°C are obviously insufficient for thermal destruction of complex molecules in combustible material **490F** and, thus, initiation of the interaction of excited carbon atoms with hydrogen.

[00211] Blind pit **538** may be equipped with heat-exchange coil **539** with a high-temperature heat carrier circulating in it, which maintains the temperature in the zone of hydrogenation reaction at the level of 390-420°C. Hydrogen supply **450** into the zone of coal hydrogenation is realized using a vertical set of bubblers **540** installed on the periphery of blind pit **538** in such a way that jets of gas **450** are introduced tangentially to the internal side wall of the hollow cylinder. At the temperature of 390-420°C and pressure 10-12 MPa, in the presence of zinc chloride with the admixture of ammonium paramolybdate and elementary sulfur as catalyst (originating, e.g., from solution **480** and from paste-forming substance **470**), carbon contained in the original mineral actively reacts both with molecular hydrogen (supplied into blind pit **538** in the hot state from the facility for the conversion of methane capped from the original raw material in the course of its size reduction) and participates in the reaction of hydrogenation of coaly substance **490F** by atomic hydrogen split off from the components of paste-forming substance (primarily, tetralin), which reveals, in this connection, an elevated reactionary activity.

[00212] Hot hydrogen **450** may be supplied from a system of methane conversion and introduced under a high pressure into blind pit **538** tangentially to its internal cylindrical surface through several connection pipes arranged at various height levels, to ensure not only a fine control of the thermal regime of hydrogenation, but also to be used as a mixing agent. Since the height mark of the site of the original flow feed to hydrogenation exceeds the level of the discharge of the produced mixture of hydrocarbons (**490G**) rising along the annular gap between well **535** and axial pipe **534**, artificial petroleum obtained as a result of hydrogenation reaction gets into the empty space of the broadened part of the head of well **535**.

[00213] In the course of the counterflow of the material flows **490F**, **490G**, a recuperative heat exchange occurs between the hot artificial petroleum **490G** rising from blind pit **538** and fresh coal/oil mixture descending in the opposite direction along the axial pipe **534**. The mixture of hydrocarbons **490G** that has ascended from the hydrogenation zone in blind pit **538** and reached the ground surface enters separator **541**, which is a ground-surface head of well **535** and represents a hollow vertical hermetic vessel in the form of an upside-down can. The main product of the process is collected as combustible fluid and hydrogenated material **490H**. The vapor/gaseous phase of product **490H** may be separated from liquid products thereof and further processed. The obtained vapor/gas mixture may be supplied from hot separator **541** through nozzle **542** to processing, and as a result, the unreacted hydrogen (as a gas that cannot condense in this system) may be returned to blind pit **538** for its repeated use in the hydrogenation process. The gases dissolved in rising liquid **490G** may be discharged due to the pressure drop above the surface. The vapor/gas mixture discharged from this hydrocarbon liquid may be fed to the recuperation of its heat to corresponding external heat-exchange equipment (not shown). After that, it may be directed to a cold separator (not shown) for cooling, condensation and subsequent separation with a discharge of hydrogen-containing recirculation gas returned into the process and a light condensed hydrogenate.

[00214] Final cleaning and processing of the residues of the hydrogenation product, after combustible fluid and hydrogenated material **490H** has been separated from it, may be carried out in a residue purification and separation subsystem **620B**. The liquid mixture of high-boiling hydrogenation residual products (**489B**), while being released from the dissolved gases and liquid combustible material, may be still contaminated by residues of solid non-liquefied material. Mixture **489B** is discharged from the lower part of separator **541** into refrigerator **544** by lateral nozzle **543** and is accumulated in thickener **545**, wherefrom the condensed sludge is fed to deep squeezing of the impregnating liquid phase into a filtering centrifuge of periodic action **546**.

[00215] The cake periodically squeezed on centrifuge **546** is cleaned on it (in a periodic mode, too) from the last impregnating residues of the heavy hydrogenate with an organic solvent **440**, e.g., petroleum-ether (a mixture of light hydrocarbons, predominantly saturated, with five and six carbon atoms). Then, it passes through drier **547** to yield a residual product **490I** and waste **489C** which is recharged onto belt conveyor **548**, which transports this wastage into mixer **518** for mixing with the moist heavy product removed out of the initial energy mineral as early as at the first stage of its grinding. The discharge of thickener **545** is combined with the filtrate of centrifuge **546**, and the obtained in this way heavy hydrogenate, which is already completely free from the solid phase, is directed to further processing, which is performed, however, at a petroleum distillation plant.

[00216] Waste treatment subsystem **620A** may receive waste material from all stages of the process, e.g., waste **489** from floating separation subsystem **610A**, waste **489A** from milling and grinding subsystems **630A**, **640A**, **640B**, **640C**, and also waste **489C** from residue purification and separation subsystem **620B**. Moist mixture of solid wastes obtained in mixer **518** is cleaned with hot fresh water from last residues of mineral salts carried out of the technological process by means of multi-stage countercurrent washing on band vacuum-filter **509**, ground in hermetic mill **510** (simultaneously capturing methane). Then, it is removed out of the production cycle and arranged in the worked-out space as a cheap backfilling material. Rinse water obtained in the process of countercurrent washing, which represents a dilute solution of zinc chloride in water with an admixture of molybdenum-containing compounds, is directed from sump **549** by pump **550** to evaporator system **551** for evaporation. Thin water vapor released in the course of evaporation of the solution is liquefied in condenser **552**. The obtained fresh hot condensate is returned to the first stage of countercurrent washing of solid waste on band vacuum filter **509**. Aqueous solution of zinc chloride with the remaining admixtures of molybdenum-containing compounds, which was restored to the required original density of 1.423 g/cm^3 by evaporation, is removed by pump **511** from the internal circulation loop of evaporator system **551** to the head of the process, i.e., to the system of hydrostatic coal hoisting. Thus, the production cycle of zinc chloride and molybdenum-containing compounds used as aqueous salt solution **480** in the process, as well as the production cycle of mineral salts catalyzing the hydrogenation process, may be practically closed. At proper production standards, irreversible losses of these substances are minor.

[00217] Hence, advantageously, the methods and systems described above in the coal-mining industry for producing artificial liquid fuel in underground conditions are power-saving and ecologically clean, and their use may contribute to an essential increase in technical and economic efficiency of processing combustive minerals, especially those notable for elevated contents of incombustible mineral admixtures. At the same time, the extraction of complex materials is ensured (at the expense of associated methane extraction out of the original raw material), and the liquefaction may be complete (due to elevated purity of coal concentrate supplied for hydrogenation, which is, besides, thoroughly impregnated by the catalyst of hydrogenation process and has not been in contact with air oxygen in the process of its transportation and grinding). This reduces the specific consumption of the original solid energy mineral per ton of the obtained liquid product. Besides, harmful impact of underground mining and artificial liquid fuel production on the natural environment is essentially weakened, because all the waste of such an enterprise is arranged in the underground worked-out space. Moreover, the discharge of ready product – artificial petroleum produced by coal mines in underground conditions – instead of drawing non-beneficiated solid fuel to the ground surface, allow not only to cancel such powerful electric power consumers as cable-skip hoists (the power of electric drives of modern mine hoists reaches 15,000 kW) and coal cleaning plants (total electric power of drives at the ground-surface facilities can reach 10,000 kW) from the mine equipment, but also completely reject the services of railway transport. In this case, it is much more profitable to deliver the product to its destinations by pipeline transport, which is about three times cheaper than railway transport (not to mention mechanical losses of solid fuel because of coal dust blown out of railway cars by wind.

[00218] Advantageously, the disclosed methods and systems may be of special interest for deep and extra-deep deposits of energy minerals. For example, today, record depths reached by coal-mining industry approach 2000 meters. Coal liquefaction at such extreme depths leads to the growth of working pressure in the zone of its hydrogenation up to 21-22 MPa (without attracting power inputs from outside), which considerably intensifies such underground technological process and drastically facilitates the conversion of even the most carbonized kinds of combustible minerals into artificial petroleum. However, according to modern geological science, coal series stretch to much greater depths, which opens the prospects of the development of these huge stores of energy minerals not for producing solid fuel, but for mining industry conversion from coal to ecologically clean production of synthetic liquid fuel. The steady growth of temperature of enclosing strata with the deepening level of underground mining allows a considerable increase of the share of gratuitous heat of the Earth interior in the total energy balance of the technological process. Furthermore, the saturation of coal and enclosing strata with methane sharply grows with increasing depth of coal strata occurrence.

[00219] Therefore, the possibility of complex usage of the power potential of the produced raw material with simultaneous extraction of methane advantageously distinguishes the method of the invention from known technologies of solid fuel processing into alternative energy carriers. A reduced requirement for hydrogen also contributes to the profitability of underground coal liquefaction in comparison with ground-surface production of artificial liquid fuel. The point is that the freshly produced energy mineral obtained from the mining face is immediately isolated from the mine atmosphere by operative submersion into water-salt medium. Thus, the atmospheric oxygen loses contact with the coaly component of the combustible mineral and initiates the mechanism of its endogenic oxidation. On the whole, the main advantage of the technological process of the invention is a steady increase of technical and economic efficiency of underground coal liquefaction, whereas conventional approaches to the production of artificial liquid fuel (having the coal liquefaction system on the ground surface) lead to irreversible growth of the prime cost of the produced artificial liquid fuel and to harmful impact of such industrial activity on the natural environment, as the underground mining reaches greater depths.

[00220] In certain embodiments, the method of combustible minerals processing comprises preliminary preparation of the original raw material by size with its subsequent gravity concentration, mixing of the obtained concentrate with paste-forming substance and coaly substance hydrogenation in a hot mode under elevated pressure, completed by the separation of a mixture of liquid products of liquefaction from the remaining solid inert residue. After the preliminary preparation of the original raw material by size realized in underground conditions, the ground material is charged into a column of liquid medium with the density intermediate between those of the combustible mineral and the waste rock prepared by water dissolving of mineral salts exerting a catalytic impact on further hydrogenation of the produced combustible mineral. Subsequently, a step-by-step wet grinding and gravity concentration of dressed material floated to the ground surface is carried out in the same water-salt medium within the framework of a three-stage dressing. Then, the obtained final concentrate is mixed with paste-forming substance, diluted with an organic solvent, rubbed to the colloidal size and fed by a hollow rotating shaft installed in the vertical well, which ends with Segner wheel, to hydrogenation in a blind pit. The hydrogenate that rises along the annular gap between the hollow rotating shaft and the vertical well is released from gases dissolved in it, separated from the solid residue, and the product of combustible mineral liquefaction is brought out to distillation into fractions.

[00221] In certain embodiments, the waste rock sunk after its charging into the column of water-salt medium is squeezed from the liquid phase, rinsed with water and ground, simultaneously capturing methane released into the gaseous phase in the course of said waste rock size reduction, whereupon it is laid into the worked-out space.

[00222] In certain embodiments, the method further comprises grinding of the floated material within the first stage of the dressing cascade is carried out at the ambient temperature in the same solution, with simultaneous capturing of the released methane, in a mill functioning within a closed cycle with the separator of the combustible mineral.

[00223] In certain embodiments, the product of the first stage of the dressing cascade roiled in water-salt solution is heated and additionally ground with simultaneous capturing of the released methane at the second stage of the dressing cascade, at the same time with its further separation under the conditions of moderate heating.

[00224] In certain embodiments, the obtained technological flow of the second stage of the dressing cascade is heated at the third stage of the dressing cascade to an even higher temperature not reaching the boiling point of the water-salt medium, whereupon its solid phase is additionally ground to the extra-fine state and, finally, precisely separated from the last residues of visible mineral admixtures in a strong centrifugal field in a hot technological mode.

[00225] In certain embodiments, waste products of the second and third stages of gravitational dressing are squeezed from the liquid phase excess and returned to wet grinding into the cycle of the first stage of the dressing cascade, with a subsequent removal out of the process together with the waste product of the first stage of the dressing cascade.

[00226] In certain embodiments, the solid residue separated from the product of the combustible mineral liquefaction is cleaned from the impregnating mixture of hydrocarbons with an organic solvent, dried and mixed with dehydrated waste product of the first stage of the dressing cascade mixed with the waste of the second and third stages of dressing, whereupon the obtained mixture of inert minerals is rinsed with fresh water together with the waste rock sunk in the column of water-salt medium, after charging the original crushed raw material into the latter.

[00227] In certain embodiments, the rinsing water remained after cleaning the process waste is evaporated to its original density and returned to the head of the process.

[00228] In certain embodiments, produced natural gas may be pressurized and liquefied using any of the embodiments described above.

[00229] In certain embodiments, the mineral salts used for preparing water-salt medium with the density intermediate between those of the combustible mineral and waste rock, may comprise individual inorganic compounds and/or their mixtures, such as zinc or tin chlorides or bromides, various iron sulfates, ammonium salts of molybdenum acids, as well as potassium formate, which exert later a positive influence on the hydrogenation process either by their catalytic effect or by atomic hydrogen detachment.

[00230] In certain embodiments, the paste-forming agent for preparing coal/oil mixture supplied to hydrogenation, may comprise organic compounds of the aromatic series, which can serve as atomic hydrogen donors, e.g., tetralin, methyl naphthalene, quinoline mixture with phenol, cresol, naphthalene solution in phenol, technical anthracene and other components of anthracene oil.

[00231] In certain embodiments, the solvent of coal/oil mixture for correcting its consistency may comprise petroleum processing products and/or individual organic compounds and their mixtures obtained by synthetic means, such as isopropanol and other alcohols.

[00232] It is noted that certain embodiments of the present invention overcome much of the transport problems of known technology by carrying out the liquefaction underground, in proximity to the actual production of the combustible material. The underground location also removes many of the environmental hazards presented by known technologies. Moreover, the separation of combustible material by floating solves both a delivery problem as well as the waste rock removal problem, as the latter may simply be returned to the underground mine after the processing described above. Finally, the energy requirements are significantly reduced by using the Segner turbine rotated by the material flow and utilizing the heat and pressures provided by the underground location of the hydrogenation chamber. The processes may be designed, as illustrated above, to involve maximal recycling of liquids that are used in the process, use hydrogen extracted from the combustible material for the hydrogenation and minimize energy consumption while maximizing the liquefaction efficiency.

[00233] In the above description, an embodiment is an example or implementation of the invention. The various appearances of "one embodiment”, "an embodiment", "certain embodiments" or "some embodiments" do not necessarily all refer to the same embodiments.

[00234] Although various features of the invention may be described in the context of a single embodiment, the features may also be provided separately or in any suitable combination. Conversely, although the invention may be described herein in the context of separate embodiments for clarity, the invention may also be implemented in a single embodiment.

[00235] Certain embodiments of the invention may include features from different embodiments disclosed above, and certain embodiments may incorporate elements from other embodiments disclosed above. The disclosure of elements of the invention in the context of a specific embodiment is not to be taken as limiting their used in the specific embodiment alone.

[00236] Furthermore, it is to be understood that the invention can be carried out or practiced in various ways and that the invention can be implemented in certain embodiments other than the ones outlined in the description above.

[00237] The invention is not limited to those diagrams or to the corresponding descriptions. For example, flow need not move through each illustrated box or state, or in exactly the same order as illustrated and described.

[00238] Meanings of technical and scientific terms used herein are to be commonly understood as by one of ordinary skill in the art to which the invention belongs, unless otherwise defined.

[00239] While the invention has been described with respect to a limited number of embodiments, these should not be construed as limitations on the scope of the invention, but rather as exemplifications of some of the preferred embodiments. Other possible variations, modifications, and applications are also within the scope of the invention. Accordingly, the scope of the invention should not be limited by what has thus far been described, but by the appended claims and their legal equivalents.

CLAIMS

What is claimed is:

1. An underwater gas pressurization unit comprising:

   at least one vertical vessel arranged to receive gas through a top of the vessel and a pressurizing liquid through a bottom of the vessel, and further comprising a layer of water-immiscible liquid upon a layer of aqueous salt solution,

   wherein a density of the pressurizing liquid is higher than a density of aqueous salt solution, which is in turn higher than a density of the water-immiscible liquid, to maintain the layer of aqueous salt solution on top of the pressurizing liquid and to maintain the layer of water-immiscible liquid on top of the layer of aqueous salt solution, and

   a valve system arranged to pressurize the gas by introducing the pressurizing liquid into the vessel, evacuate the pressurized gas through the top of the vertical vessel upon reaching a specified pressure and introduce gas into the vessel by evacuating the pressurizing liquid through the bottom of the vertical vessel.
2. The underwater gas pressurization unit of claim 1, further comprising a delivery unit in fluid communication with the valve system, arranged to receive the pressurizing liquid therefrom and deliver the pressurizing liquid thereto.
3. The underwater gas pressurization unit of claim 2, wherein the delivery unit comprises:

   a gasifier arranged to gasify the pressurizing liquid;

   a condenser located at a specified underwater depth and arranged to condense the gasified pressurizing liquid;

   a heat insulated pipework arranged to deliver the gasified pressurizing liquid from the gasifier to the condenser; and

   a container arranged to receive the condensed pressurizing liquid and deliver by gravity the pressurizing liquid to the valve system.
4. The underwater gas pressurization unit of claim 3, wherein the container is arranged to provide a specified head above the at least one vessel, the specified head configured to enable the gravitational delivery.
5. The underwater gas pressurization unit of claim 4, wherein the pressurizing liquid is selected and the at least one vessel is designed to provide the specified head at a given location.
6. The underwater gas pressurization unit of claim 1, comprising two vertical vessels which are arranged to operate reciprocally, one vessel pressurizing gas while the other vessel receiving gas.

7. The underwater gas pressurization unit of claim 1, wherein the gas is natural gas.
8. The underwater gas pressurization unit of claim 7, associated with a natural gas production platform and receiving the natural gas therefrom.
9. The underwater gas pressurization unit of claim 1,wherein the at least one vessel is arranged to withstand underwater pressure
10. An underwater natural gas liquefaction system comprising at least two underwater gas pressurization units of claim 1, comprising:

    a first unit arranged to pressurize natural gas, wherein the system further comprises a natural gas cooling unit arranged to liquefy the pressurized natural gas using a first coolant; and

    a second unit arranged to pressurize the first coolant, wherein the system further comprises a first cooling unit arranged to liquefy the pressurized first coolant.
11. The underwater natural gas liquefaction system of claim 10, wherein the pressurizing liquid is difluorodibromomethane.
12. The underwater natural gas liquefaction system of claim 10, wherein the aqueous salt solution is a calcium bromide aqueous solution and the water-immiscible liquid is a liquid hydrocarbon.
13. The underwater natural gas liquefaction system of claim 10, wherein the first cooling unit is arranged to liquefy the pressurized first coolant using a second coolant, the system further comprising a third underwater gas pressurization unit arranged to pressurize the second coolant and a second cooling unit arranged to liquefy the pressurized second coolant, and wherein the second coolant is selected to have its critical point at a higher temperature than the first coolant.
14. The underwater natural gas liquefaction system of claim 13, wherein the first coolant is ethane and the second coolant is propane.
15. An underwater natural gas liquefaction method comprising:

    pressurizing the natural gas in at least one vertical vessel by cyclically:

    introducing the natural gas into a top of the at least one vertical vessel;

    introducing a pressurizing liquid into a bottom of the at least one vertical vessel to pressurize the natural gas;

    separating the pressurizing liquid from the natural gas by a layer of water immiscible liquid which is set upon a layer of aqueous salt solution, wherein a density of the pressurizing liquid is higher than a density of aqueous salt solution, which is in turn higher than a density of the water-immiscible liquid, to maintain the layer of aqueous salt solution on top of the pressurizing liquid and to maintain the layer of water-immiscible liquid on top of the layer of aqueous salt solution; and

evacuating the pressurized gas through the top upon reaching a specified pressure;

wherein the introducing the natural gas is carried out by evacuating the pressurizing liquid from the bottom of the at least one vertical vessel.

16. The underwater natural gas liquefaction method of claim 15, further comprising delivering evacuated pressurizing liquid by gasification, upwards delivery, condensation and downwards delivery.

17. The underwater natural gas liquefaction method of claim 15, further comprising selecting the pressurizing liquid and designing the at least one vessel to provide a specified head of the pressurizing liquid with respect to the at least one vessel at a given sea location.

18. The underwater natural gas liquefaction method of claim 15, further comprising liquefying the pressurized natural gas by cooling with a first coolant, wherein the first coolant is selected to have its critical point at a higher temperature than the natural gas.

19. The underwater natural gas liquefaction method of claim 18, wherein the cooling by the first coolant comprises gasification of the first coolant and further comprising liquefying the first coolant by cooling with a second coolant, wherein the second coolant is selected to have its critical point at a higher temperature than the first coolant.

20. The underwater natural gas liquefaction method of claim 19, wherein the cooling by the second coolant comprises gasification of the second coolant and further comprising liquefying the second coolant by cooling with seawater.

21. An underwater gas pressurization unit comprising:

at least one vessel arranged to receive gas through a top of the vessel and seawater through a bottom of the vessel, and further comprising a layer of water-immiscible liquid separating between the gas and the seawater, the water-immiscible liquid selected to have a density which is intermediate between a density of the gas and a density of the seawater; and

a valve system arranged to pressurize the gas by introducing the seawater into the vessel, evacuate the pressurized gas through the top of the vessel upon reaching a specified pressure and introduce gas into the vessel by evacuating the seawater through the bottom of the vessel.

22. The underwater gas pressurization unit of claim 21, comprising at least one pair of reciprocally operating vessels, wherein one of the vessels in the at least one pair pressurizes gas while the other vessel receives gas.

23. The underwater gas pressurization unit of claim 21, wherein the at least one vessel is shaped as a vertical helix.
24. The underwater gas pressurization unit of claim 21, wherein the water-immiscible liquid comprises aliphatic or aromatic organic compounds or their mixtures, has a density smaller than seawater and a freezing temperature below -20°C.
25. The underwater gas pressurization unit of claim 24, wherein the water-immiscible liquid is selected from: hexane, hexane isomers, heptane, heptane isomers, toluene, derivatives thereof and mixtures thereof.
26. An underwater natural gas liquefaction system, comprising the underwater gas pressurization unit of claim 1, arranged to receive and pressurize natural gas from a natural gas production platform, and further comprising a cooling unit arranged to receive and liquefy the pressurized natural gas from the underwater gas pressurization unit.
27. The underwater natural gas liquefaction system of claim 26, wherein the cooling unit comprises another underwater gas pressurization unit according to claim 1, which is arranged to pressurize a coolant used in the cooling unit to liquefy the pressurized natural gas.
28. The underwater natural gas liquefaction system of claim 27, wherein the coolant is selected to have a boiling point at atmospheric pressure which is lower than a condensation temperature of the compressed natural gas and a critical condensation temperature of the pressurized coolant which is higher than a temperature of ambient seawater.
29. The underwater natural gas liquefaction system of claim 28, wherein the coolant is ethylene, and the underwater gas pressurization unit of the cooling unit is arranged to pressurize the ethylene to a pressure that enables ethylene liquefaction by cooling with ambient seawater.
30. The underwater natural gas liquefaction system of claim 26, further comprising a seawater disposal unit arranged to dispose the seawater evacuated from the underwater gas pressurization units.
31. The underwater natural gas liquefaction system of claim 30, wherein the seawater disposal unit is arranged to enable injection of the evacuated seawater into a pressurizing well associated with the natural gas production platform.
32. An underwater natural gas liquefaction method comprising:

    pressurizing the natural gas in at least one vessel by cyclically:

    introducing the natural gas into a top of the at least one vessel;

    introducing seawater into a bottom of the at least one vessel to pressurize the natural gas;

separating the introduced seawater from the natural gas by a layer of water immiscible liquid that has a density which is intermediate between densities of the natural gas and the introduced seawater; and

evacuating the pressurized gas through the top of the at least one vessel upon reaching a specified pressure of the gas,

wherein the introducing the natural gas is carried out by evacuating the seawater from the bottom of the at least one vertical vessel.

33. The underwater natural gas liquefaction method of claim 32, further comprising delivering the evacuated seawater into a pressurizing well.
34. The underwater natural gas liquefaction method of claim 32, further comprising liquefying the pressurized natural gas.
35. The underwater natural gas liquefaction method of claim 34, wherein the liquefying is carried out using a coolant which is pressurized according to the underwater natural gas liquefaction method of claim 32.
36. An underwater gas field development method comprising the underwater natural gas liquefaction method of claim 32 and delivering the evacuated the evacuated seawater into a pressurizing well to enhance gas production.
37. The underwater gas field development method of claim 36, further comprising remotely controlling an amount of delivered evacuated seawater into the pressurizing well.
38. The underwater gas field development method of claim 36, further comprising generating electricity from the flow of delivered evacuated seawater into the pressurizing well.
39. A method of separating and hydrogenating combustible material, the method comprising:

separating the combustible material from waste rock gravitationally in an aqueous salt solution selected to have a density which is intermediate between a density of the combustible material and a density of the waste rock;

heating and grinding the separated combustible material to yield a paste of purified combustible material;

fluidizing the paste; and

hydrogenating the fluidized paste in association with a Segner turbine.

40. The method of claim 39, further comprising successively reducing particle size of the separated combustible material in the solution and removing residual waste rock and gas therefrom,

wherein the heating and grinding comprises heating and grinding the combustible material of reduced particle size.

41. The method of claim 40, further comprising recycling the aqueous salt solution which is removed in the separating and in the successive particle size reduction.
42. The method of claim 40, wherein the aqueous salt solution is selected to catalyze the separating and the successive particle size reduction.
43. The method of claim 40, wherein the successive particle size reduction is carried out within the aqueous salt solution.
44. The method of claim 39, further comprising processing the hydrogenated paste to yield hydrocarbons of specified compositions.
45. The method of claim 39, wherein the aqueous salt solution comprises at least one of: potassium formate, zinc chloride, ammonium paramolybdate, nanoaqueous ferric iron sulfate ($Fe_2(SO_4)_3{\cdot}9H_2O$), ammonium paramolybdate ($(NH_4)_6Mo_7O_{24}{\cdot}4H_2O$), ammonium tetramolybdate ($(NH_4)_2{\cdot}4MoO_3{\cdot}2H_2O$), iron vitriol ($FeSO_4{\cdot}7H_2O$), bivalent tin chloride $SnCl_2$, with penta-aqueous chloride of quadrivalent tin ($SnCl_4{\cdot}5H_2O$), zinc bromide, and mixtures thereof.
46. The method of claim 39, further comprising using an aromatic paste forming agent to yield the paste.
47. The method of claim 46, wherein the paste forming agent comprises at least one of: tetralin, methyl naphthalene, quinoline mixture with phenol, cresol, naphthalene solution in phenol, anthracene and components of anthracene oil.
48. The method of claim 39, wherein the fluidizing is carried out by mixing the paste with a diluting fluid which comprises an organic solvent.
49. A system for processing combustible material, comprising:

a floating subsystem arranged to gravitationally separate the combustible material from waste rock in an aqueous salt solution selected to have a density which is intermediate between a density of the combustible material and a density of the waste rock;

a heated grinding subsystem arranged to heat and grind the separated combustible material to yield a paste of purified combustible material;

a paste fluidizing subsystem arranged to fluidize the paste; and

a hydrogenation subsystem arranged to hydrogenate the fluidized paste in association with a Segner turbine.

50. The system of claim 49, further comprising a milling subsystem arranged to successively reduce a particle size of the separated combustible material in the solution and to remove residual waste rock and gas therefrom, wherein the heated grinding subsystem is arranged to heat and grind the combustible material of reduced particle size to yield the paste.
51. The system of claim 50, wherein the particle size reduction is carried out within the aqueous salt solution.
52. The system of claim 49, further comprising a residue purification and separation subsystem arranged to separate additional product from residues of the hydrogenated material.
53. The system of claim 49, wherein the floating subsystem is arranged to receive the combustible material within an underground mine and wherein the hydrogenation subsystem is arranged to carry out the hydrogenation within the underground mine.
54. The system of claim 49, wherein the aqueous salt solution comprises at least one of: potassium formate, zinc chloride, ammonium paramolybdate, nanoaqueous ferric iron sulfate ($Fe_2(SO_4)_3 \cdot 9H_2O$), ammonium paramolybdate ($(NH_4)_6Mo_7O_{24} \cdot 4H_2O$), ammonium tetramolybdate ($(NH_4)_2 \cdot 4MoO_3 \cdot 2H_2O$), iron vitriol ($FeSO_4 \cdot 7H_2O$), bivalent tin chloride $SnCl_2$, with penta-aqueous chloride of quadrivalent tin ($SnCl_4 \cdot 5H_2O$), zinc bromide, and mixtures thereof.
55. The system of claim 49, wherein the heated grinding subsystem applies an aromatic paste forming agent to yield the paste, the paste forming agent comprising at least one of: tetralin, methyl naphthalene, quinoline mixture with phenol, cresol, naphthalene solution in phenol, anthracene and components of anthracene oil.
56. The system of claim 49, wherein the hydrogenation subsystem comprises:

a vertical shaft arranged to receive the fluidized paste and maintain a downwards flow thereof;

a Segner turbine in fluid communication with the vertical shaft and arranged to be rotated by the flowing fluidized paste;

a hydrogenation chamber enclosing a bottom portion of the vertical shaft and the Segner turbine, the hydrogenation chamber comprising a heating unit arranged to heat the fluidized paste and a hydrogen supply arranged to introduce hydrogen into the fluidized paste that exits the Segner turbine, to hydrogenate the fluidized paste; and

a vertical enclosure in fluid communication with the hydrogenation chamber and arranged to maintain an upwards flow of the hydrogenated fluidized paste from the hydrogenation chamber while enabling recuperative heat exchange between the rising hydrogenated fluidized paste and the downwards flow of fluidized paste.

57. A hydrogenation unit comprising:

a vertical shaft arranged to receive a fluid combustible material and maintain a downwards flow thereof;

a Segner turbine in fluid communication with the vertical shaft and arranged to be rotated by the flowing fluid combustible material;

a hydrogenation chamber enclosing a bottom portion of the vertical shaft and the Segner turbine, the hydrogenation chamber comprising a heating unit arranged to heat the fluid combustible material and a hydrogen supply arranged to introduce hydrogen into the fluid combustible material that exits the Segner turbine, to yield a hydrogenated combustible fluid; and

a vertical enclosure in fluid communication with the hydrogenation chamber and arranged to maintain an upwards flow of the hydrogenated combustible fluid from the hydrogenation chamber while enabling recuperative heat exchange between the rising hydrogenated combustible fluid and the downwards flow of fluid combustible material.

58. The hydrogenation unit of claim 57, wherein the vertical shaft and the vertical enclosure are at least one kilometer long and the Segner turbine is in an underground mine for combustible material that is used to generate the fluid combustible material.

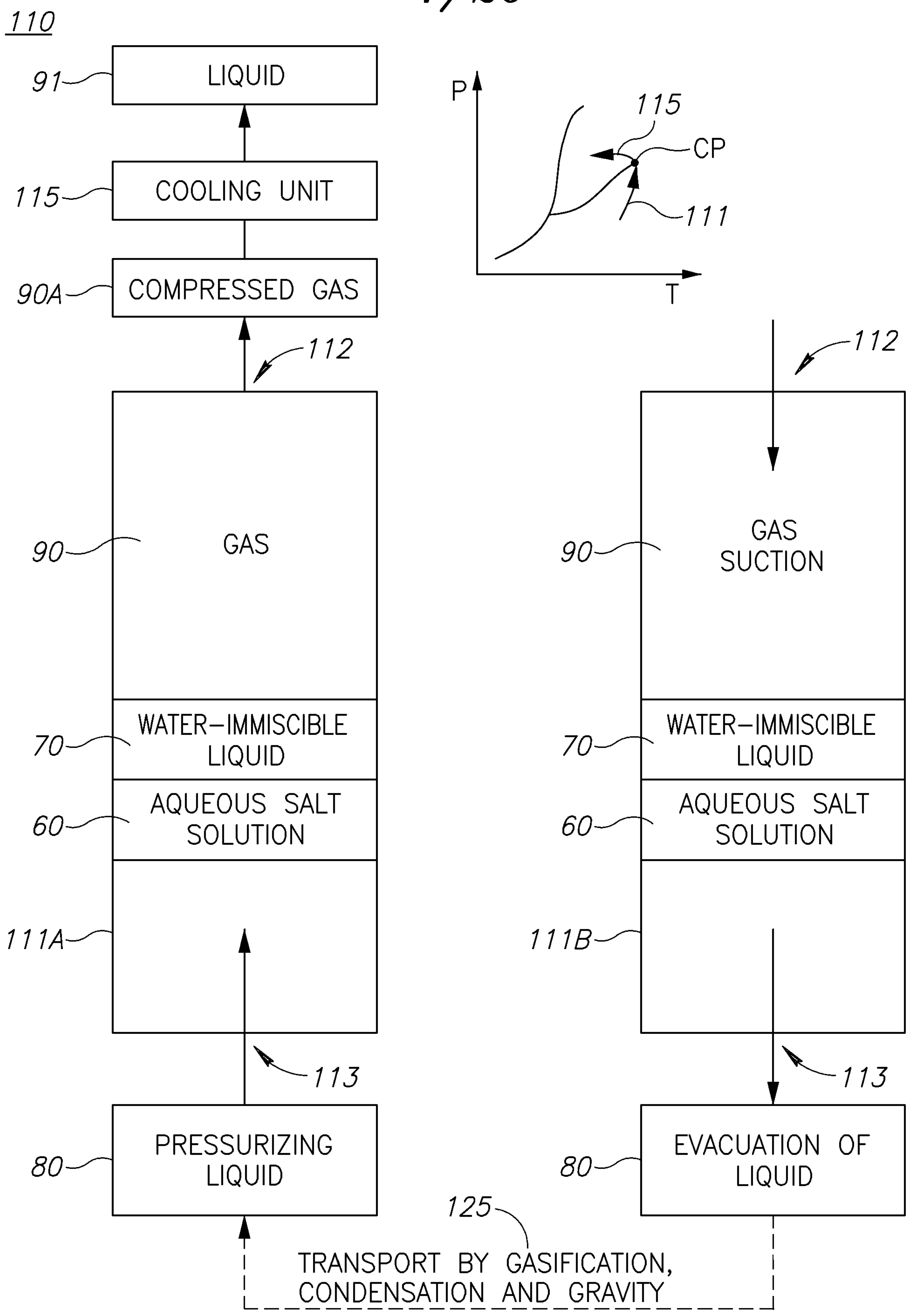
110
91
LIQUID
115
COOLING UNIT
90A
COMPRESSED GAS
112
P
T
115
CP
111
90
GAS
70
WATER–IMMISCIBLE LIQUID
60
AQUEOUS SALT SOLUTION
111A
113
80
PRESSURIZING LIQUID
112
90
GAS SUCTION
70
WATER–IMMISCIBLE LIQUID
60
AQUEOUS SALT SOLUTION
111B
113
80
EVACUATION OF LIQUID
125
TRANSPORT BY GASIFICATION, CONDENSATION AND GRAVITY

Figure 1

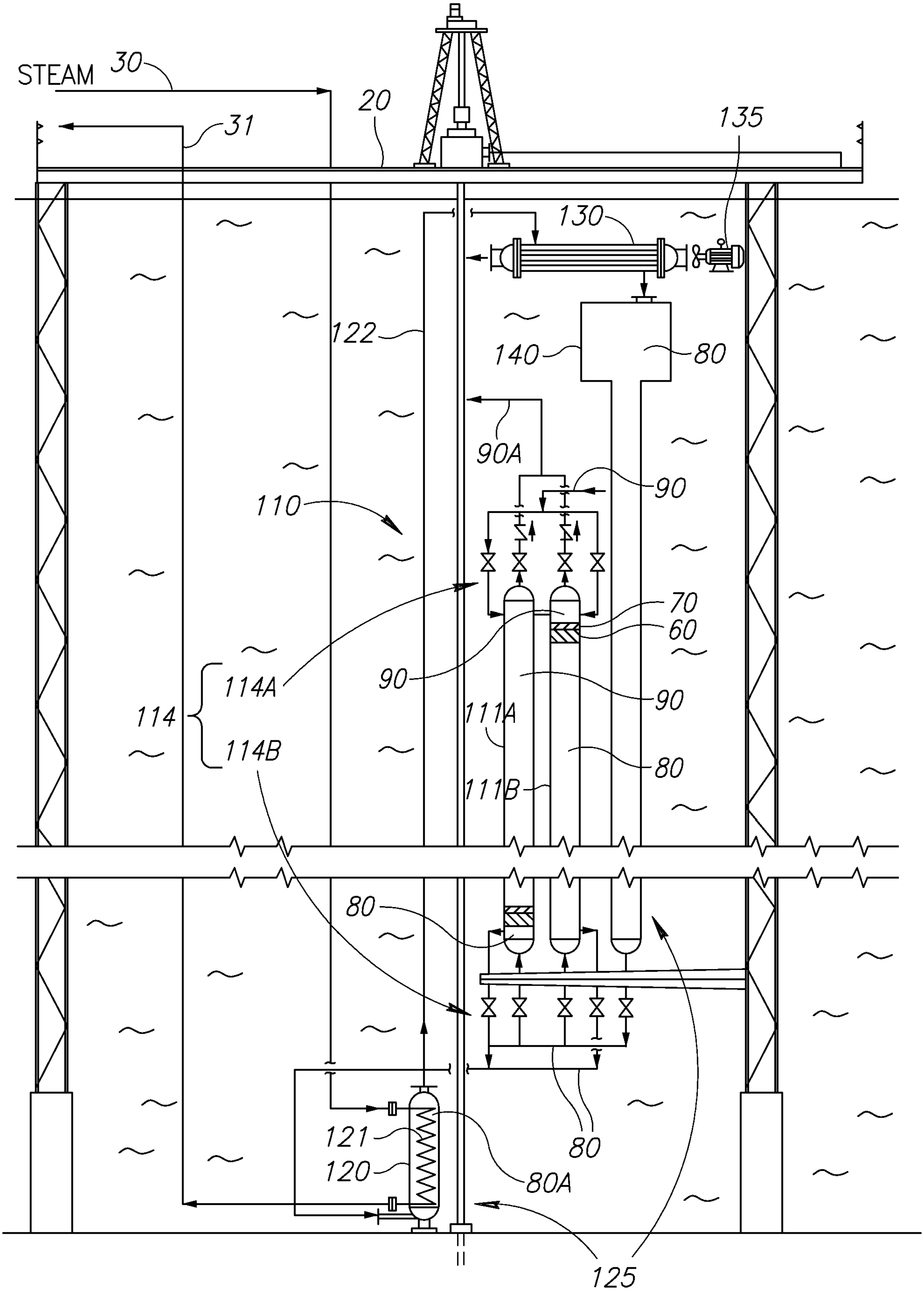
STEAM
30
31
20
135
130
122
140
80
90A
90
110
70
60
90
114A
114
114B
90
111A
111B
80
80
80
121
120
80A
80
125

Figure 2

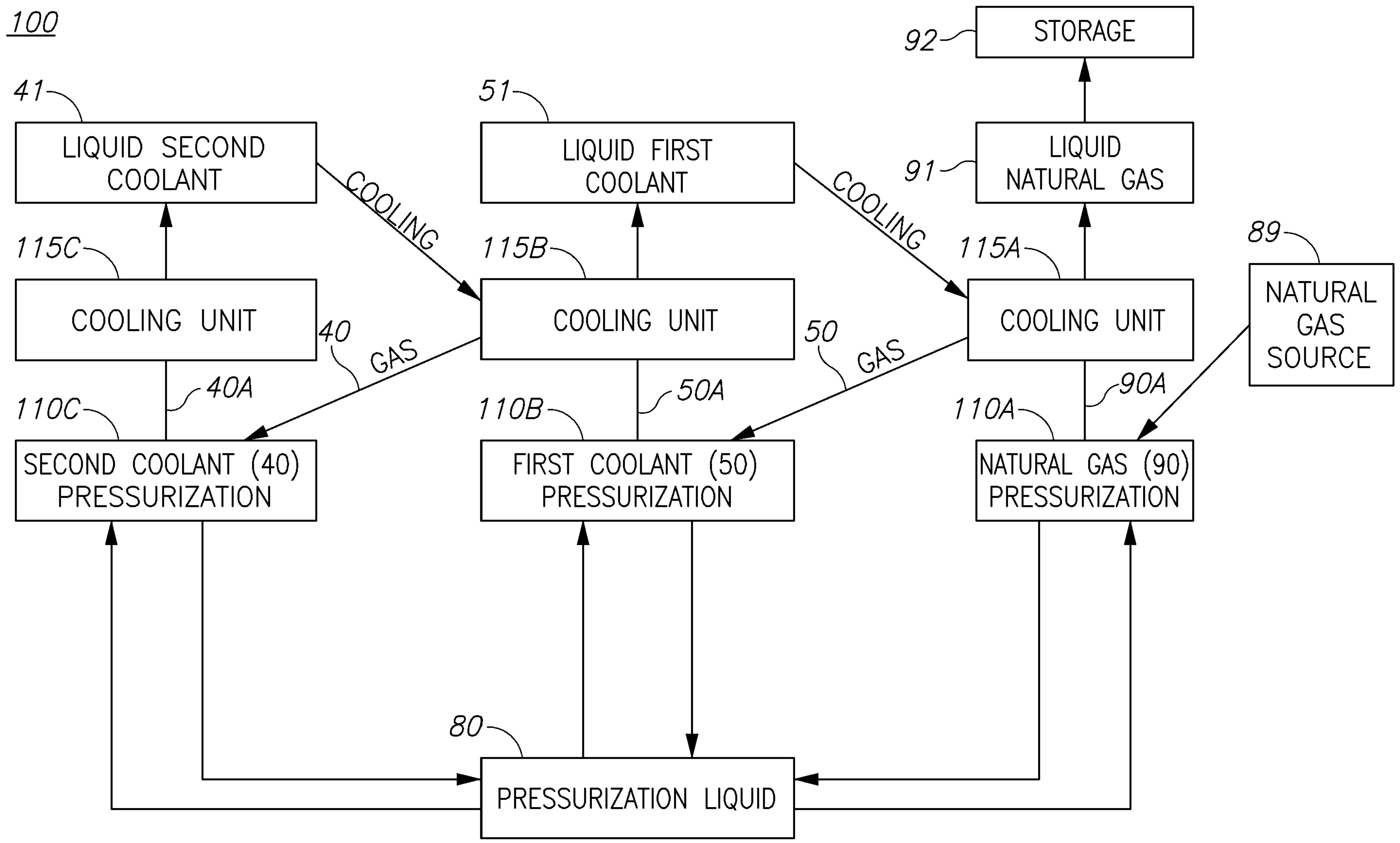
100
41
LIQUID SECOND COOLANT
51
LIQUID FIRST COOLANT
92
STORAGE
91
LIQUID NATURAL GAS
COOLING
COOLING
115C
COOLING UNIT
115B
COOLING UNIT
115A
COOLING UNIT
89
NATURAL GAS SOURCE
40
GAS
50
GAS
40A
50A
90A
110C
SECOND COOLANT (40) PRESSURIZATION
110B
FIRST COOLANT (50) PRESSURIZATION
110A
NATURAL GAS (90) PRESSURIZATION
80
PRESSURIZATION LIQUID

Figure 3

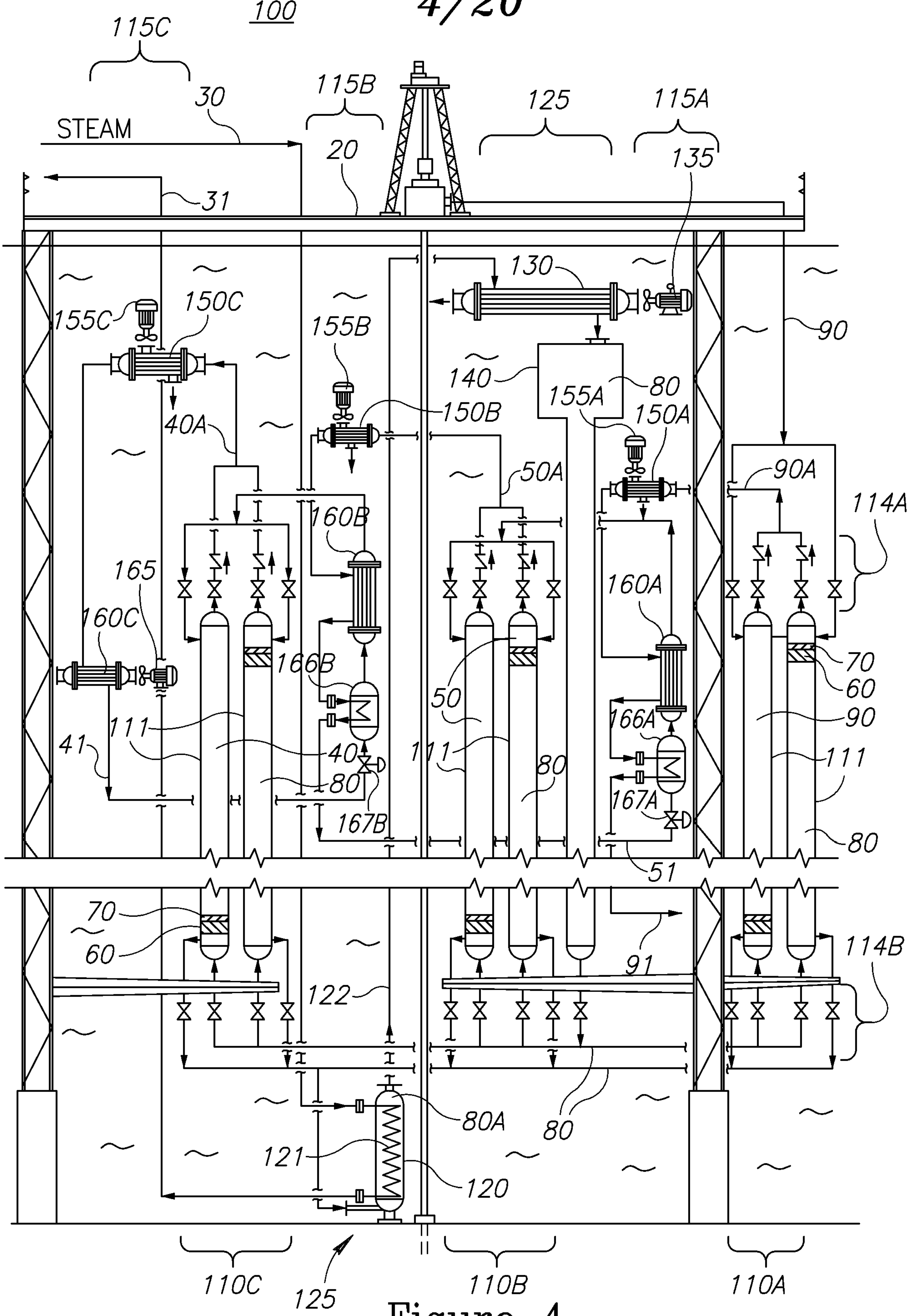
100
115C
30
STEAM
115B
20
125
115A
135
31
130
155C
150C
155B
90
140
155A
80
150B
150A
40A
50A
90A
114A
160B
165
160A
160C
70
60
166B
50
90
111
166A
111
41
40
111
80
111
80
167A
167B
80
51
70
60
91
114B
122
80A
80
121
120
110C
125
110B
110A

Figure 4

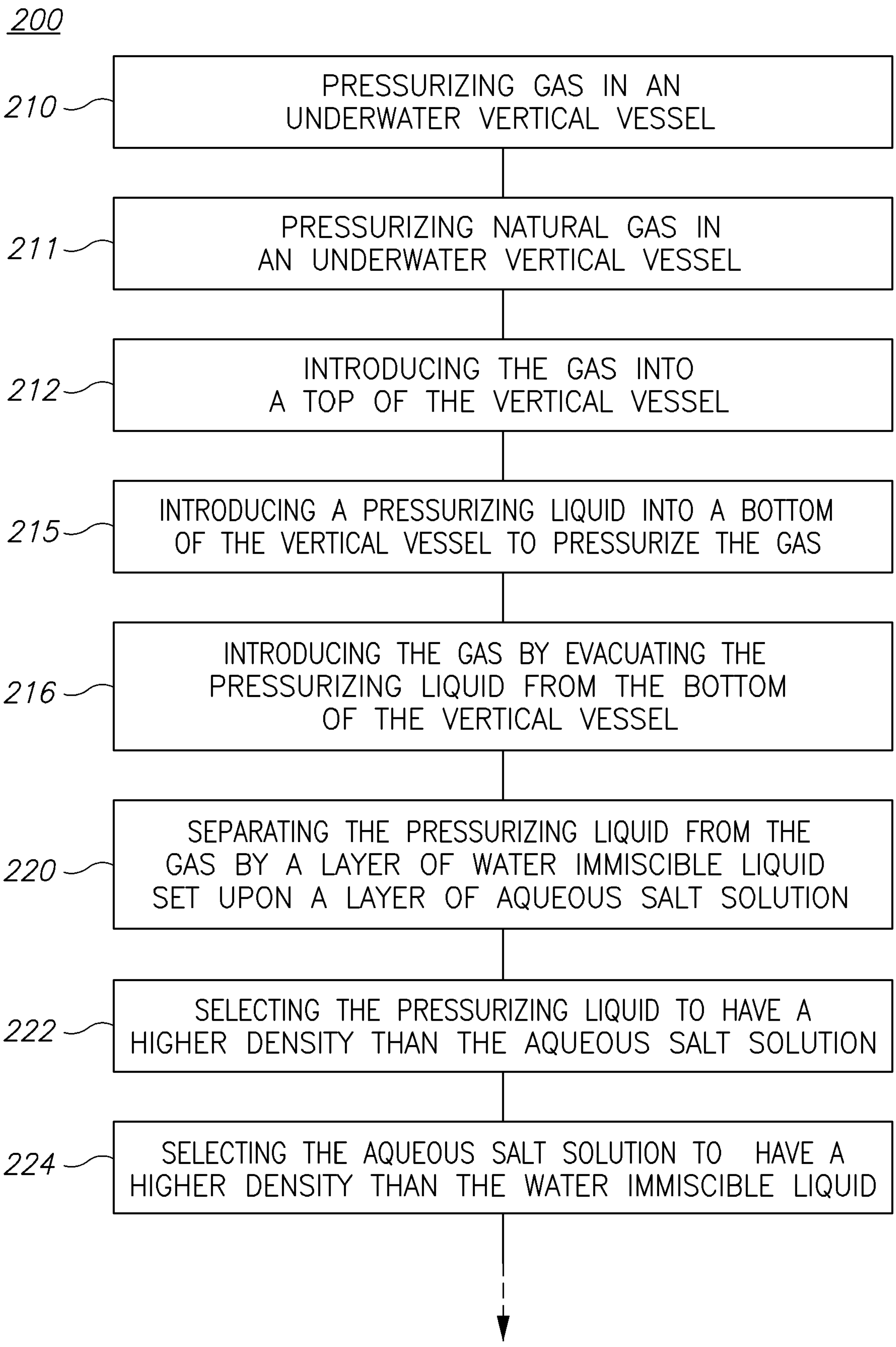
200
210
PRESSURIZING GAS IN AN UNDERWATER VERTICAL VESSEL
211
PRESSURIZING NATURAL GAS IN AN UNDERWATER VERTICAL VESSEL
212
INTRODUCING THE GAS INTO A TOP OF THE VERTICAL VESSEL
215
INTRODUCING A PRESSURIZING LIQUID INTO A BOTTOM OF THE VERTICAL VESSEL TO PRESSURIZE THE GAS
216
INTRODUCING THE GAS BY EVACUATING THE PRESSURIZING LIQUID FROM THE BOTTOM OF THE VERTICAL VESSEL
220
SEPARATING THE PRESSURIZING LIQUID FROM THE GAS BY A LAYER OF WATER IMMISCIBLE LIQUID SET UPON A LAYER OF AQUEOUS SALT SOLUTION
222
SELECTING THE PRESSURIZING LIQUID TO HAVE A HIGHER DENSITY THAN THE AQUEOUS SALT SOLUTION
224
SELECTING THE AQUEOUS SALT SOLUTION TO HAVE A HIGHER DENSITY THAN THE WATER IMMISCIBLE LIQUID

Figure 5

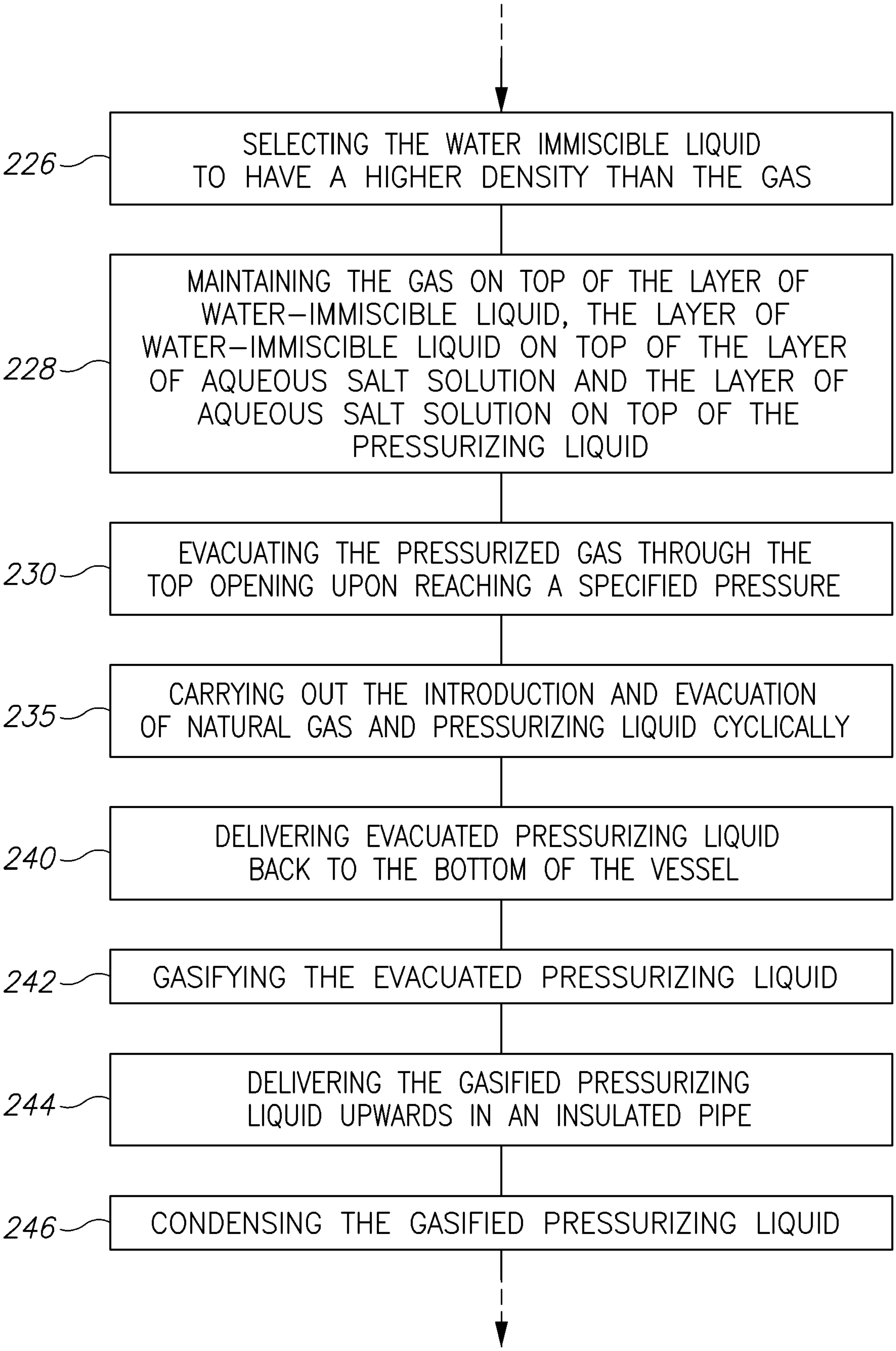

Figure 5 (cont. 1)

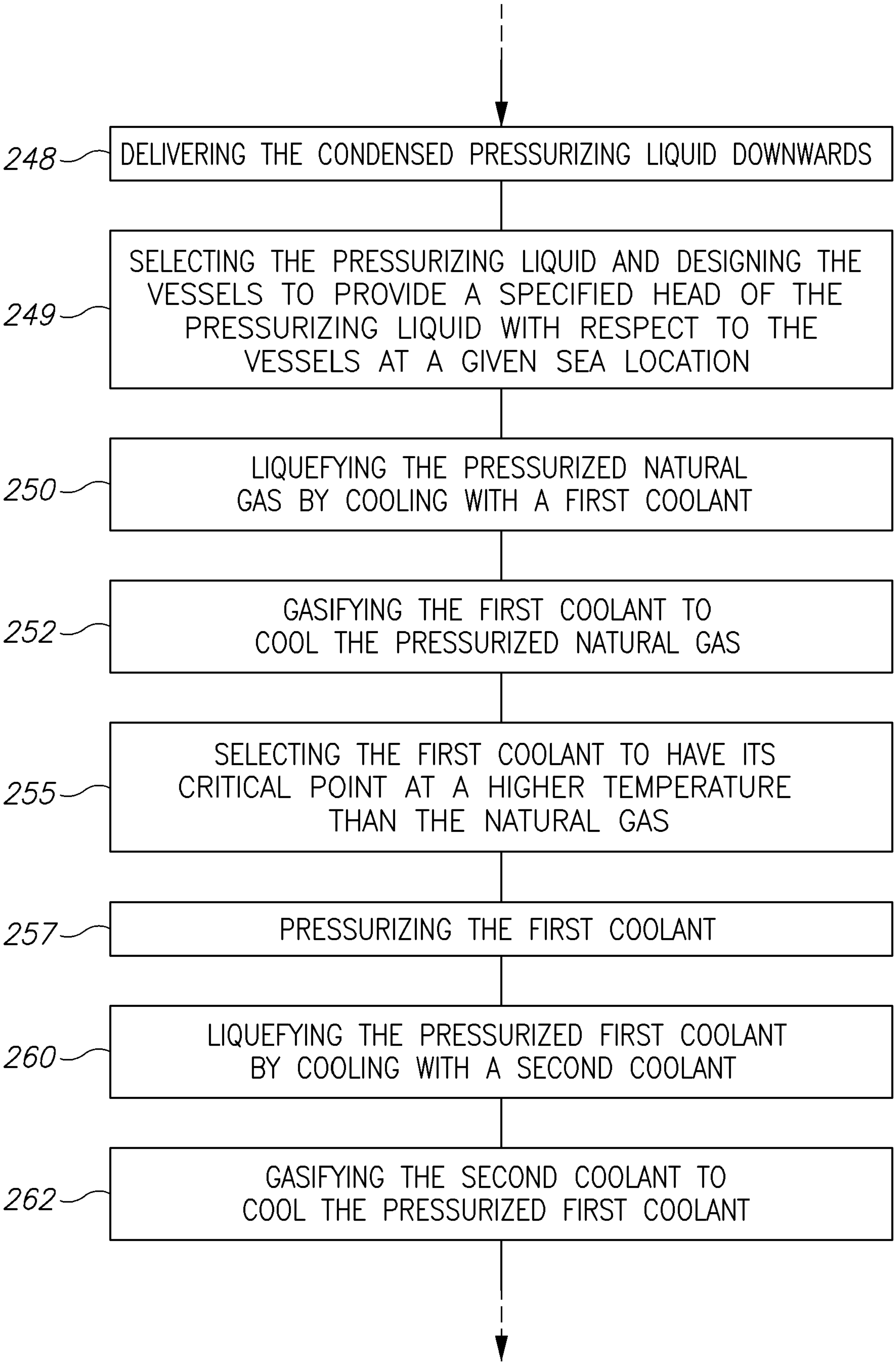

Figure 5 (cont. 2)

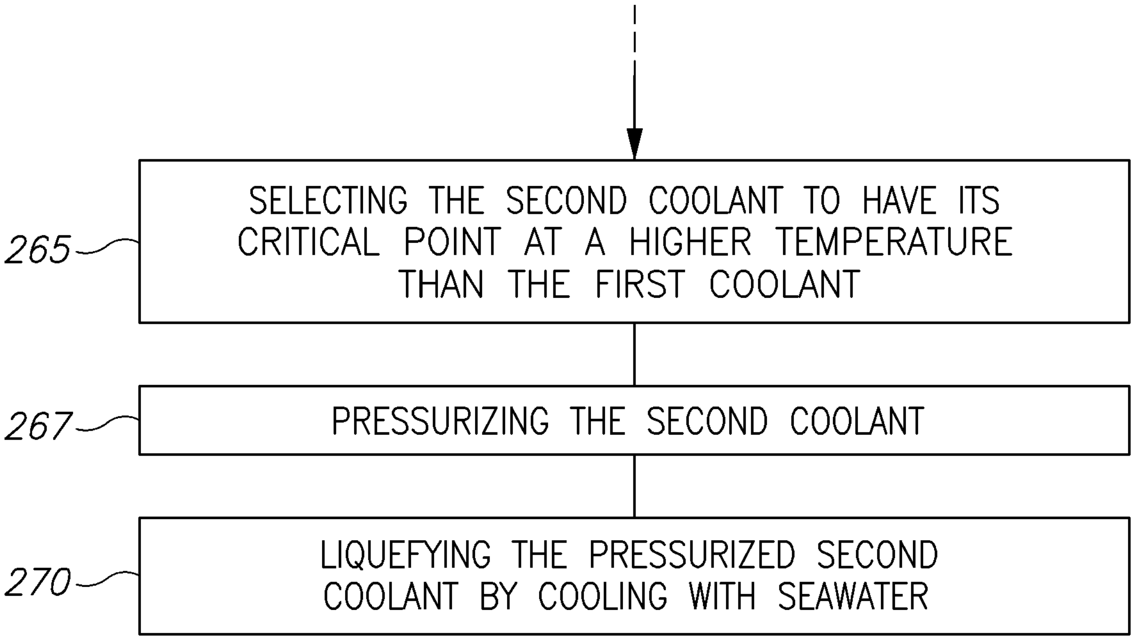

Figure 5 (cont. 3)

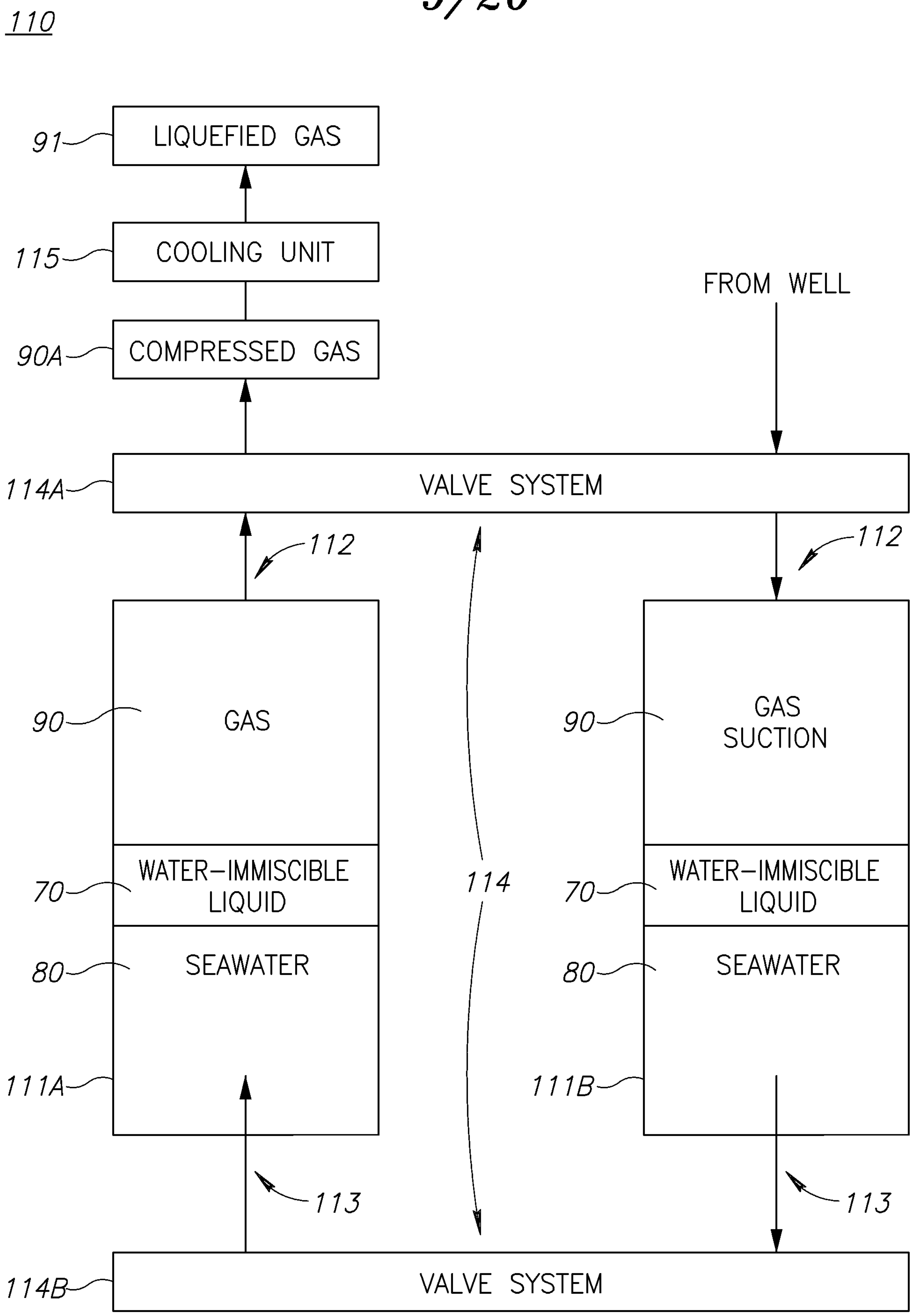
110
91
LIQUEFIED GAS
115
COOLING UNIT
FROM WELL
90A
COMPRESSED GAS
114A
VALVE SYSTEM
112
112
90
GAS
90
GAS
SUCTION
70
WATER–IMMISCIBLE
LIQUID
114
70
WATER–IMMISCIBLE
LIQUID
80
SEAWATER
80
SEAWATER
111A
111B
113
113
114B
VALVE SYSTEM

Figure 6

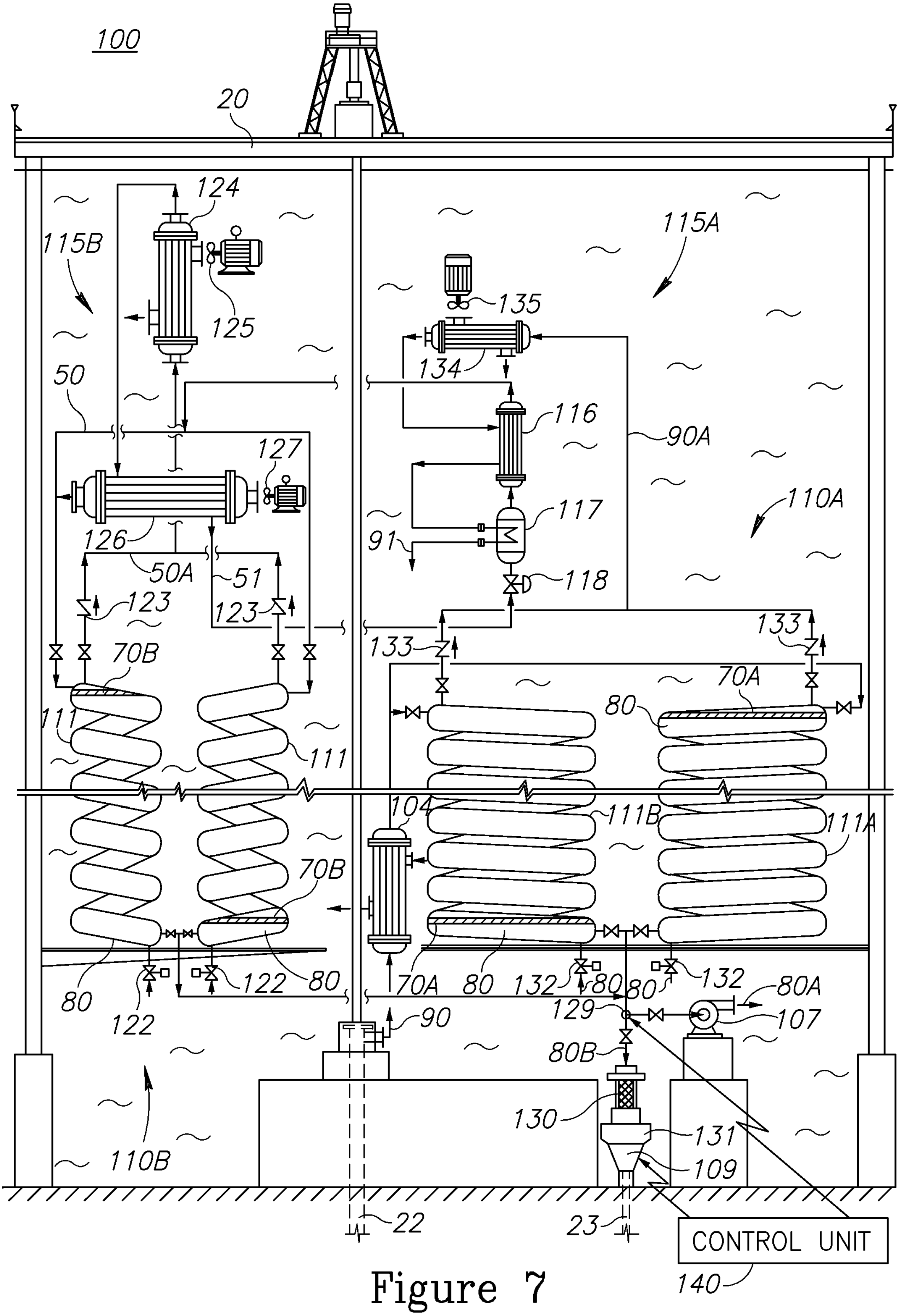
100
20
124
115B
125
115A
135
134
116
90A
50
127
110A
126
117
91
50A
51
118
123
123
133
133
70B
70A
80
111
111
104
111B
111A
70B
80
80
122
122
70A
80
132
80
80
132
80A
129
107
90
80B
130
131
110B
109
22
23
CONTROL UNIT
140

Figure 7

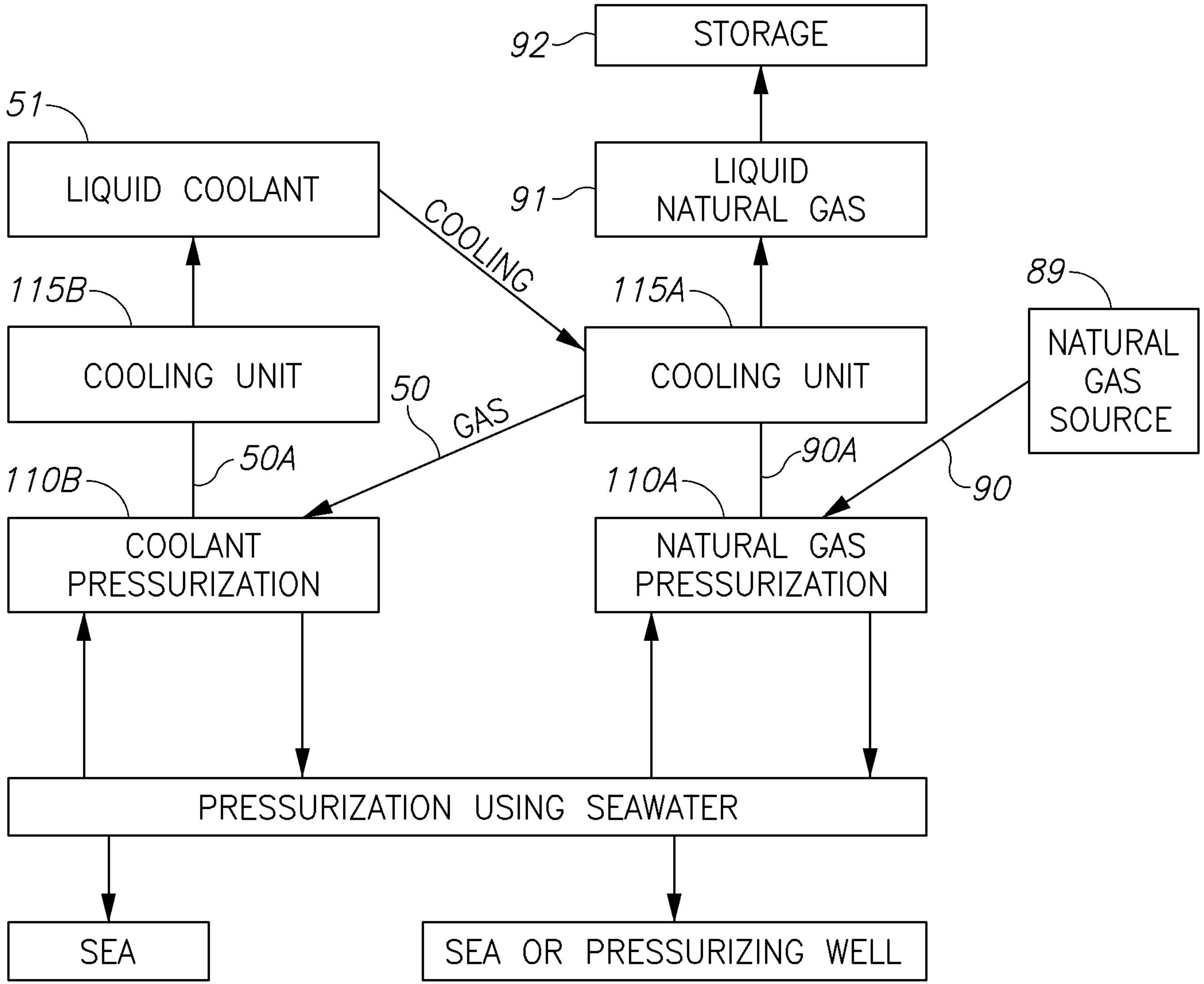
92
STORAGE
51
LIQUID COOLANT
91
LIQUID NATURAL GAS
COOLING
115B
115A
89
COOLING UNIT
COOLING UNIT
NATURAL GAS SOURCE
50
GAS
50A
90A
90
110B
110A
COOLANT PRESSURIZATION
NATURAL GAS PRESSURIZATION
PRESSURIZATION USING SEAWATER
SEA
SEA OR PRESSURIZING WELL

Figure 8

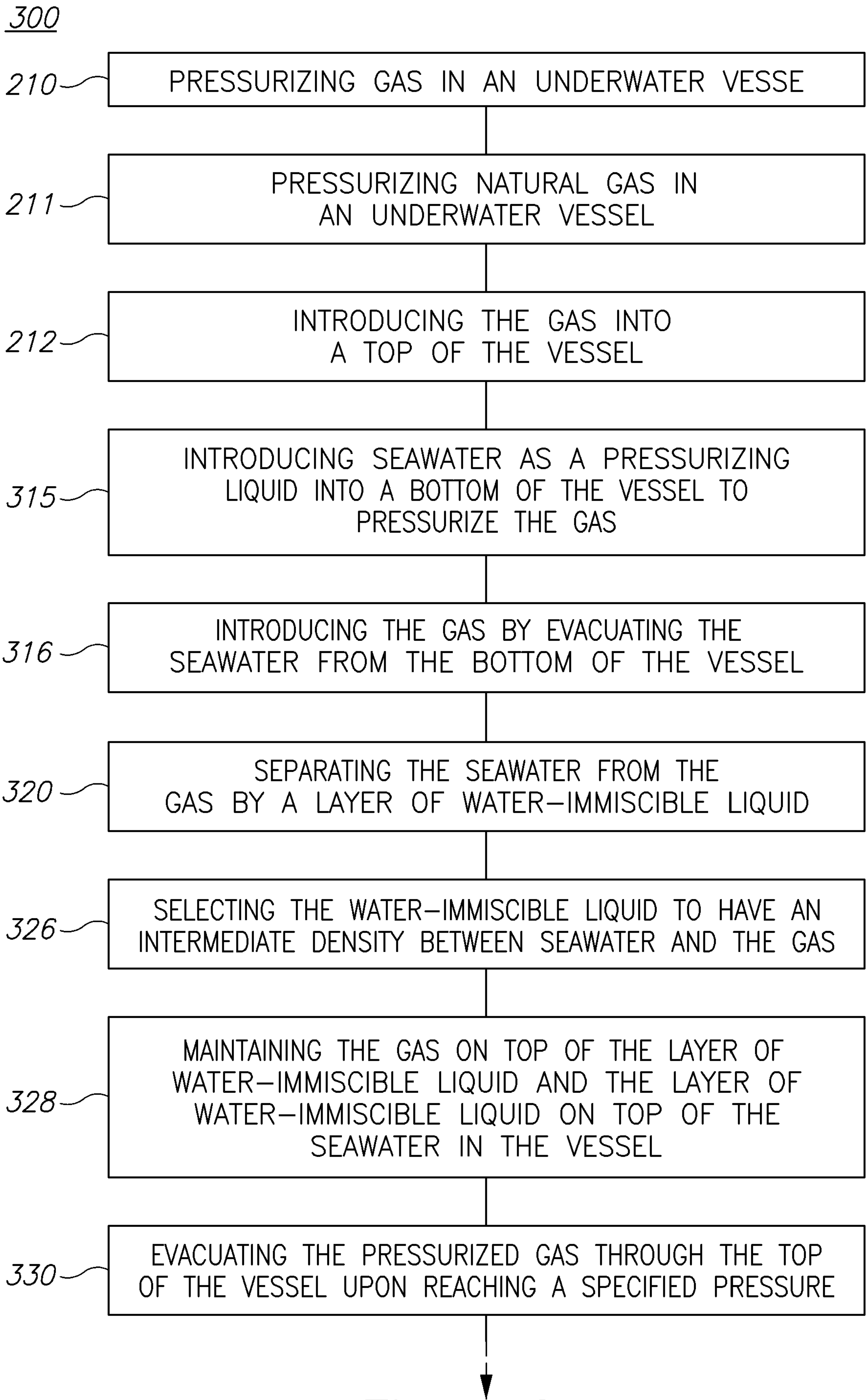
300
210
PRESSURIZING GAS IN AN UNDERWATER VESSE
211
PRESSURIZING NATURAL GAS IN AN UNDERWATER VESSEL
212
INTRODUCING THE GAS INTO A TOP OF THE VESSEL
315
INTRODUCING SEAWATER AS A PRESSURIZING LIQUID INTO A BOTTOM OF THE VESSEL TO PRESSURIZE THE GAS
316
INTRODUCING THE GAS BY EVACUATING THE SEAWATER FROM THE BOTTOM OF THE VESSEL
320
SEPARATING THE SEAWATER FROM THE GAS BY A LAYER OF WATER-IMMISCIBLE LIQUID
326
SELECTING THE WATER-IMMISCIBLE LIQUID TO HAVE AN INTERMEDIATE DENSITY BETWEEN SEAWATER AND THE GAS
328
MAINTAINING THE GAS ON TOP OF THE LAYER OF WATER-IMMISCIBLE LIQUID AND THE LAYER OF WATER-IMMISCIBLE LIQUID ON TOP OF THE SEAWATER IN THE VESSEL
330
EVACUATING THE PRESSURIZED GAS THROUGH THE TOP OF THE VESSEL UPON REACHING A SPECIFIED PRESSURE

Figure 9

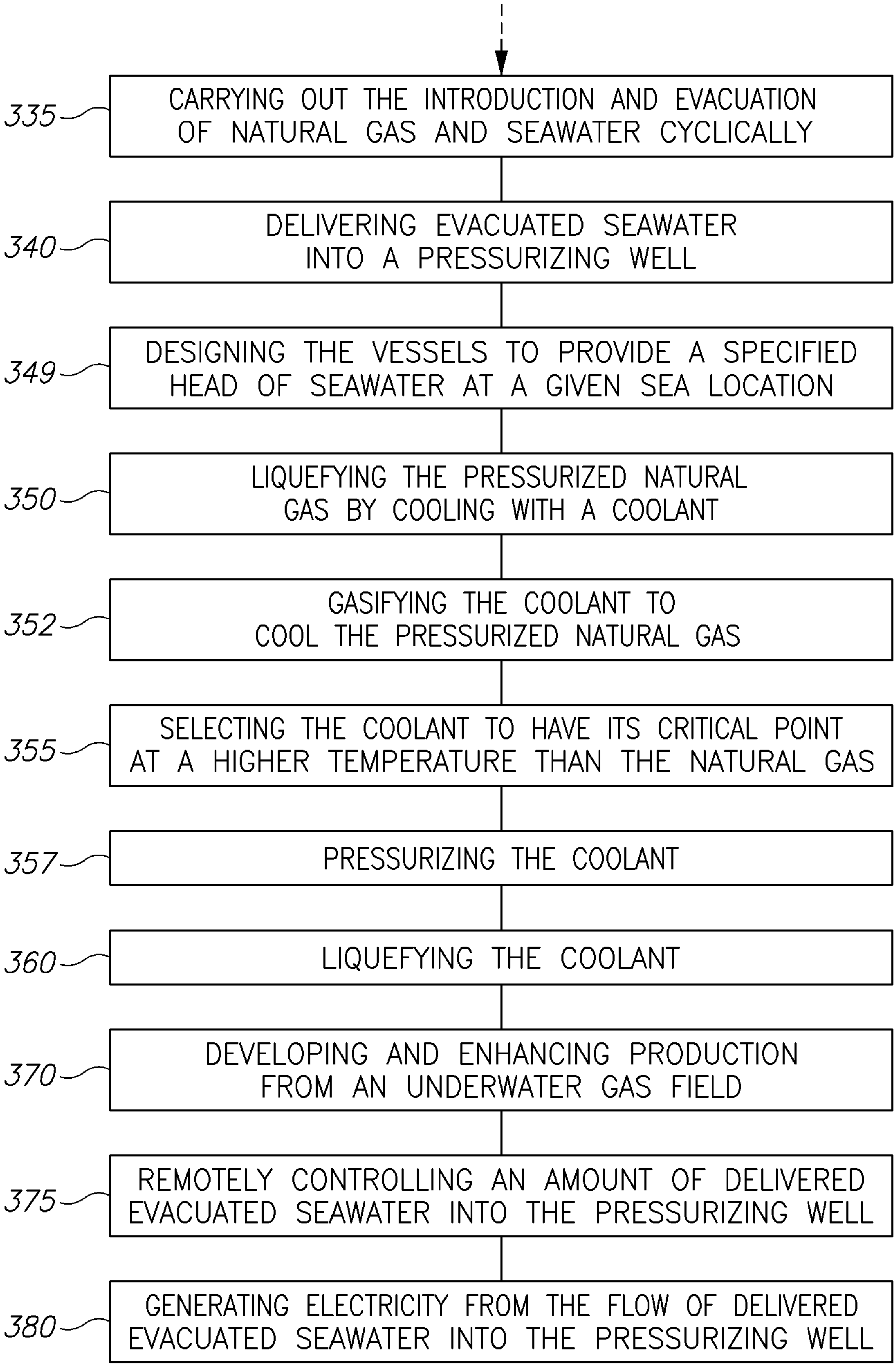

Figure 9 (cont. 1)

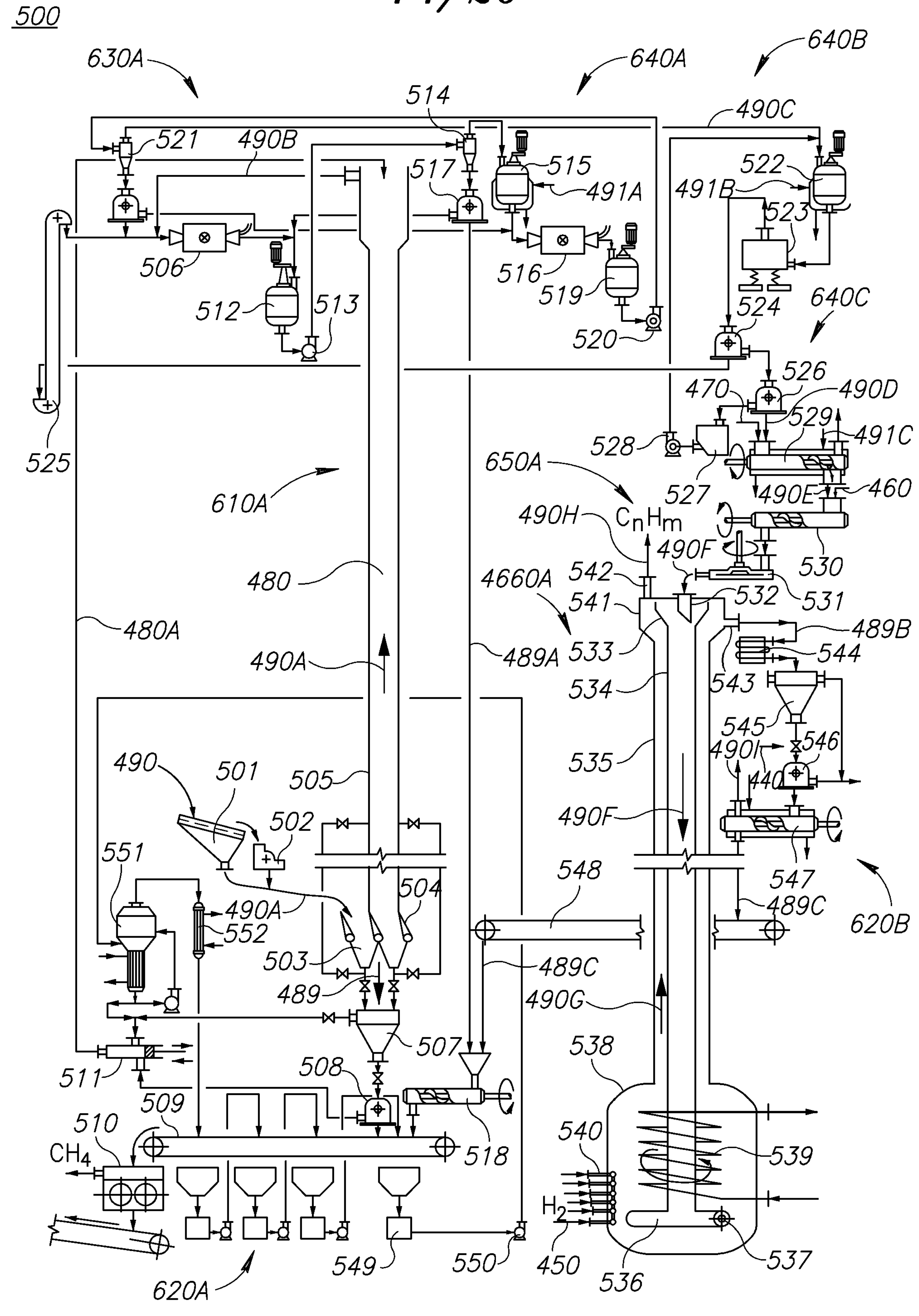
500
630A
640A
640B
514
490C
521
490B
515
517
491A
522
491B
523
506
516
512
513
519
520
524
640C
525
526
470
490D
528
529
491C
650A
527
490E
460
610A
490H
C_nH_m
490F
530
480
542
531
4660A
541
532
533
489B
480A
544
490A
489A
543
534
545
490I
546
440
535
490
501
505
502
490F
547
551
548
504
490A
489C
620B
552
503
489C
489
490G
507
538
508
511
518
509
510
540
539
CH_4
H_2
537
549
550
450
536
620A

Figure 10A

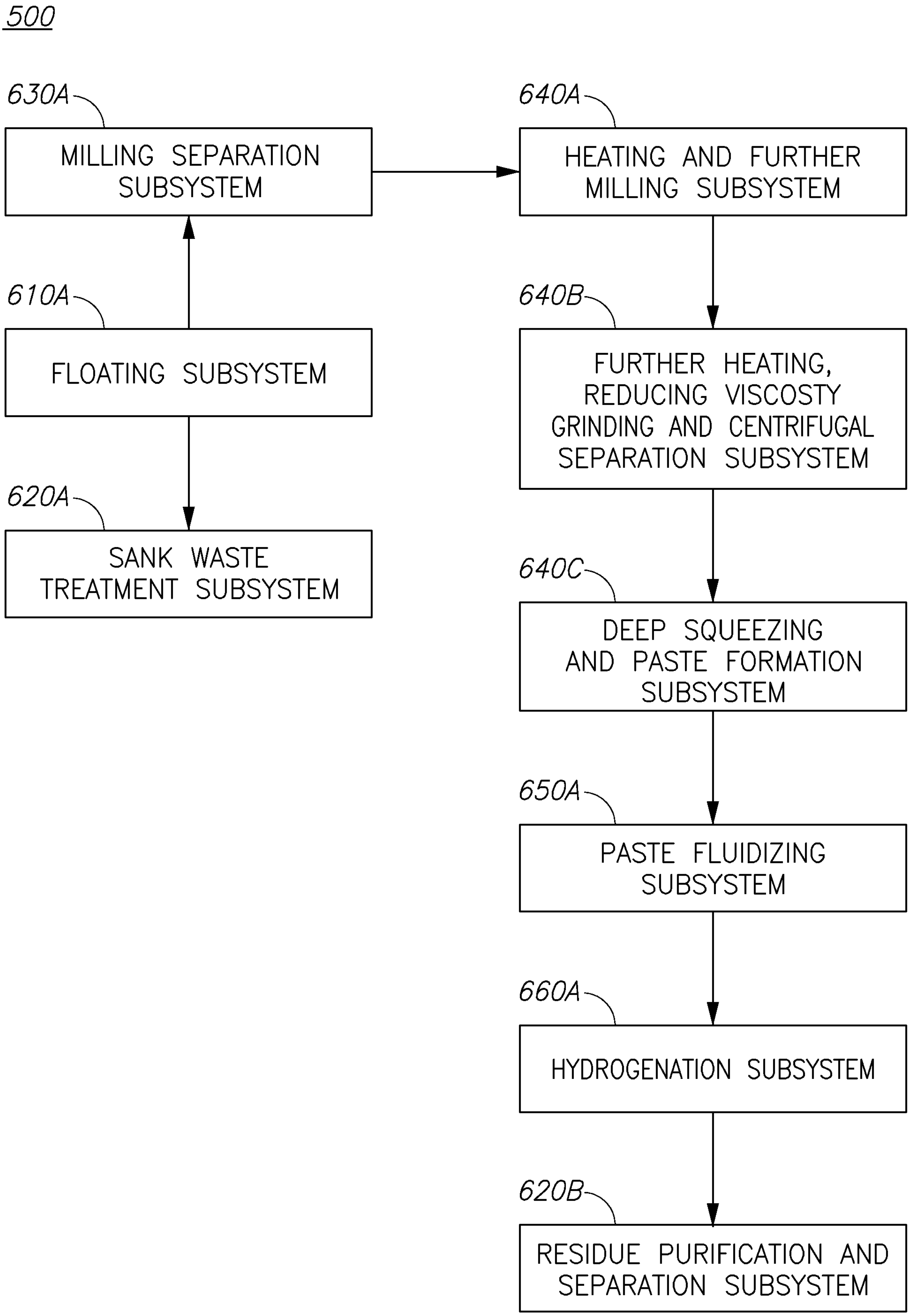
500
630A
MILLING SEPARATION SUBSYSTEM
640A
HEATING AND FURTHER MILLING SUBSYSTEM
610A
FLOATING SUBSYSTEM
640B
FURTHER HEATING, REDUCING VISCOSTY GRINDING AND CENTRIFUGAL SEPARATION SUBSYSTEM
620A
SANK WASTE TREATMENT SUBSYSTEM
640C
DEEP SQUEEZING AND PASTE FORMATION SUBSYSTEM
650A
PASTE FLUIDIZING SUBSYSTEM
660A
HYDROGENATION SUBSYSTEM
620B
RESIDUE PURIFICATION AND SEPARATION SUBSYSTEM

Figure 10B

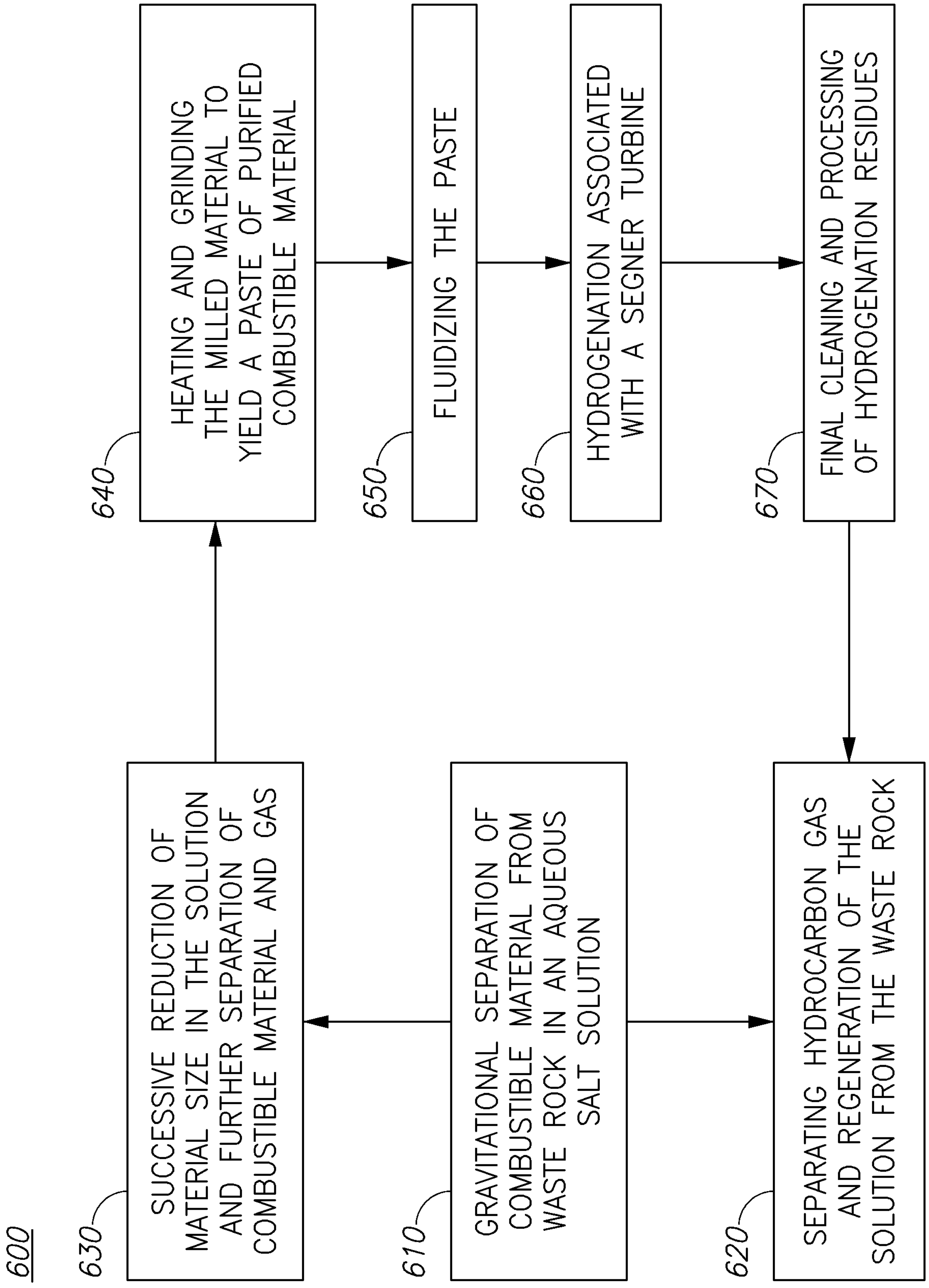
600
610
GRAVITATIONAL SEPARATION OF COMBUSTIBLE MATERIAL FROM WASTE ROCK IN AN AQUEOUS SALT SOLUTION
620
SEPARATING HYDROCARBON GAS AND REGENERATION OF THE SOLUTION FROM THE WASTE ROCK
630
SUCCESSIVE REDUCTION OF MATERIAL SIZE IN THE SOLUTION AND FURTHER SEPARATION OF COMBUSTIBLE MATERIAL AND GAS
640
HEATING AND GRINDING THE MILLED MATERIAL TO YIELD A PASTE OF PURIFIED COMBUSTIBLE MATERIAL
650
FLUIDIZING THE PASTE
660
HYDROGENATION ASSOCIATED WITH A SEGNER TURBINE
670
FINAL CLEANING AND PROCESSING OF HYDROGENATION RESIDUES

Figure 11A

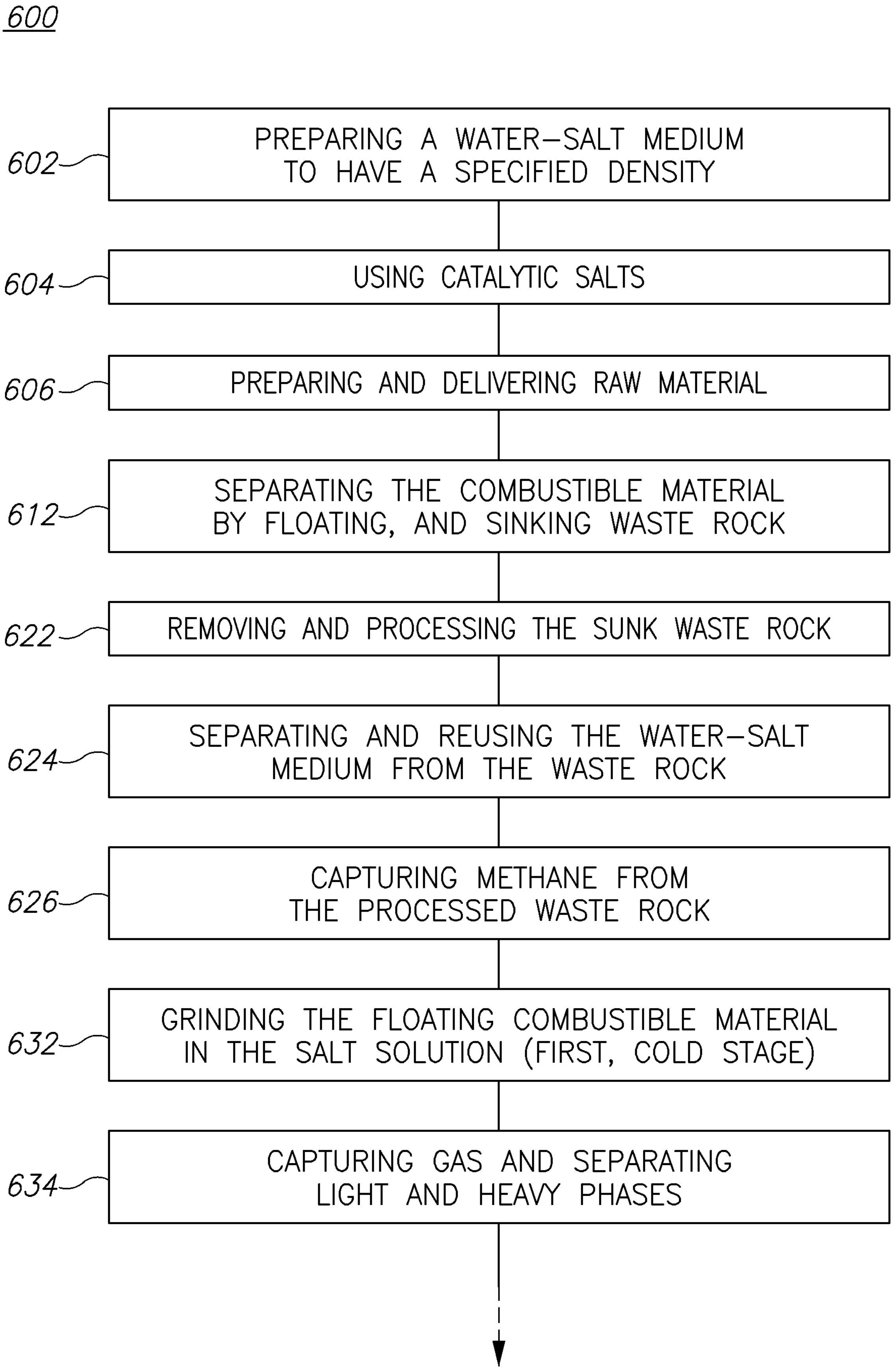
600
602
PREPARING A WATER–SALT MEDIUM TO HAVE A SPECIFIED DENSITY
604
USING CATALYTIC SALTS
606
PREPARING AND DELIVERING RAW MATERIAL
612
SEPARATING THE COMBUSTIBLE MATERIAL BY FLOATING, AND SINKING WASTE ROCK
622
REMOVING AND PROCESSING THE SUNK WASTE ROCK
624
SEPARATING AND REUSING THE WATER–SALT MEDIUM FROM THE WASTE ROCK
626
CAPTURING METHANE FROM THE PROCESSED WASTE ROCK
632
GRINDING THE FLOATING COMBUSTIBLE MATERIAL IN THE SALT SOLUTION (FIRST, COLD STAGE)
634
CAPTURING GAS AND SEPARATING LIGHT AND HEAVY PHASES

Figure 11B

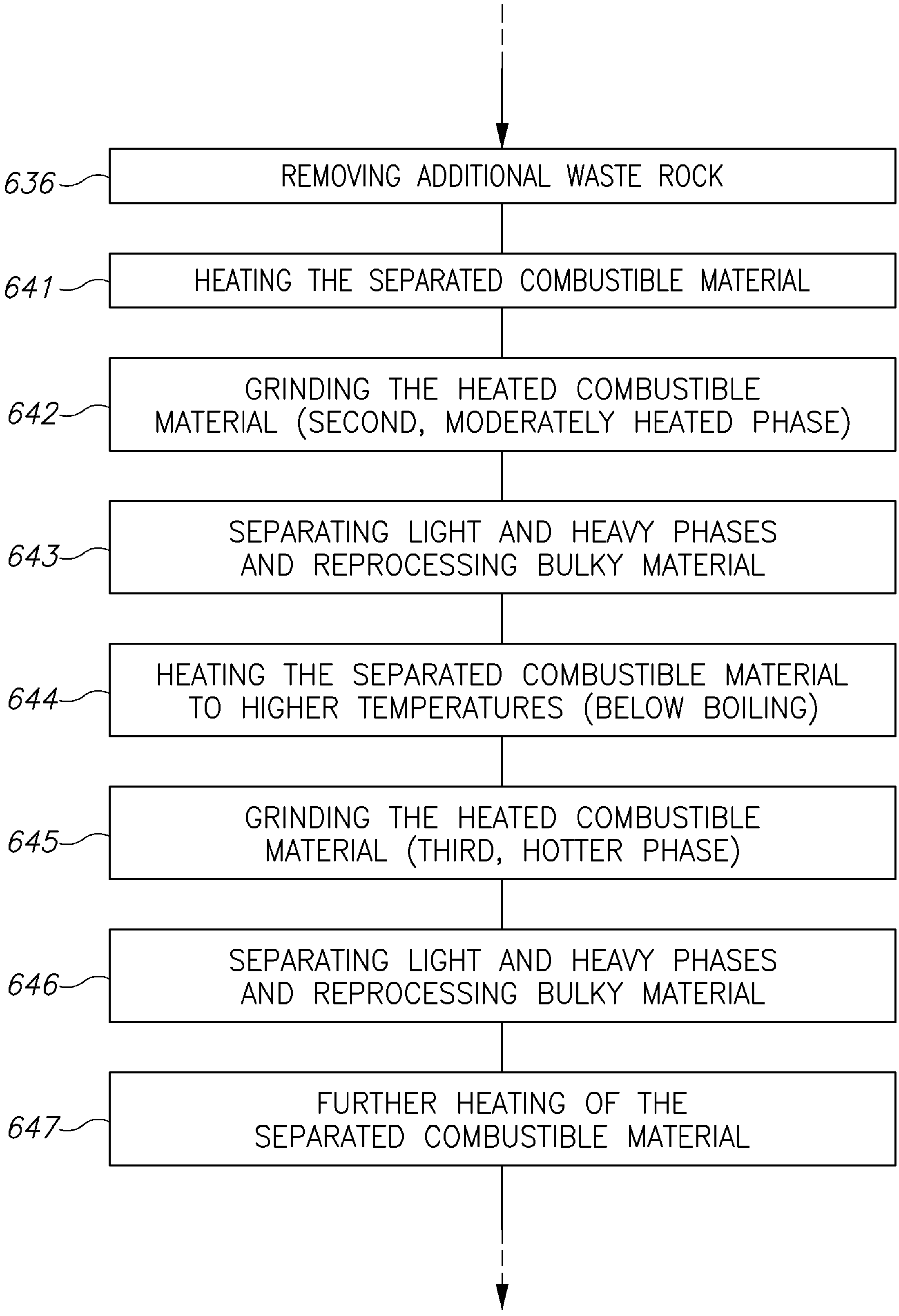

Figure 11B (cont. 1)

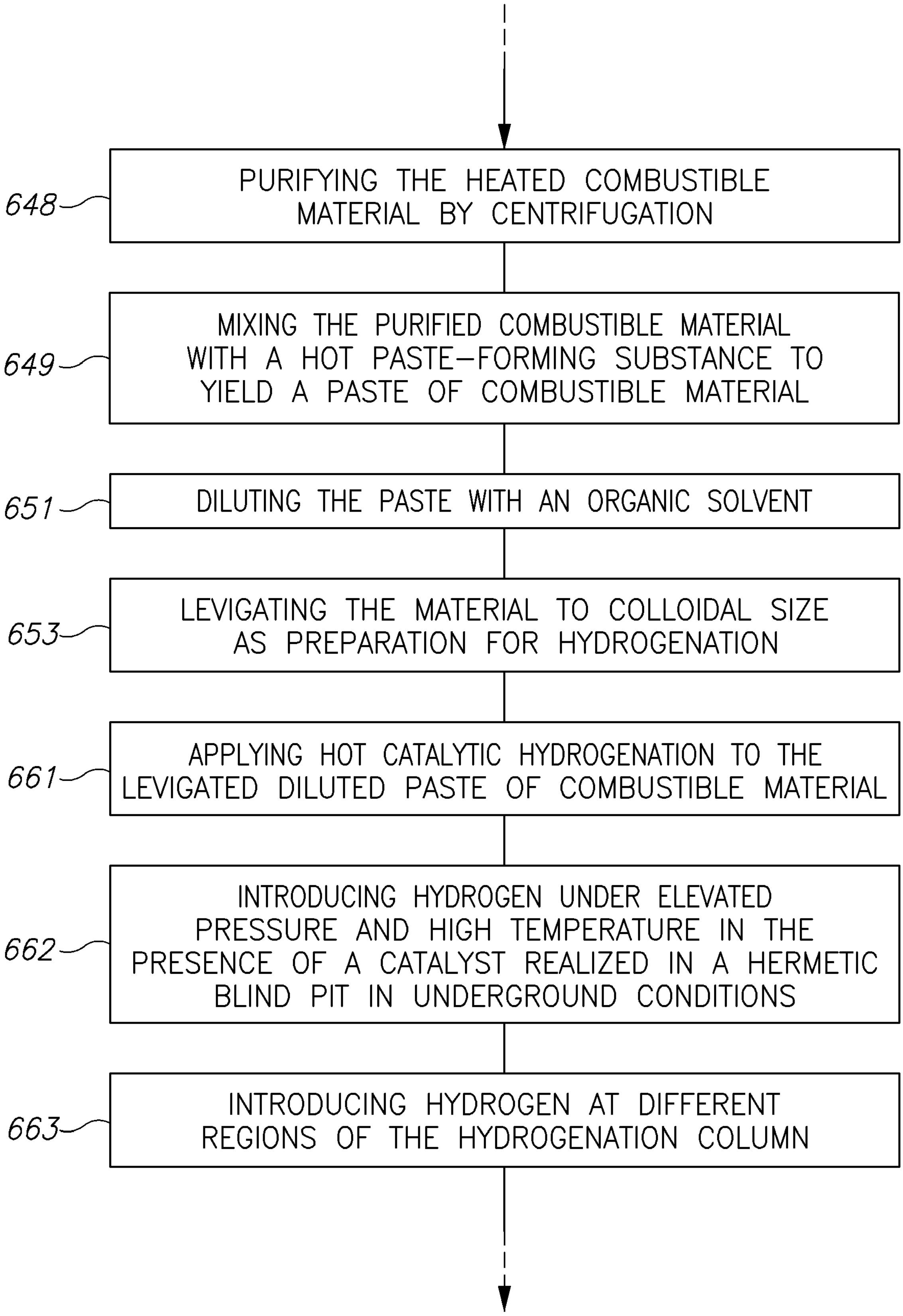

Figure 11B (cont. 2)

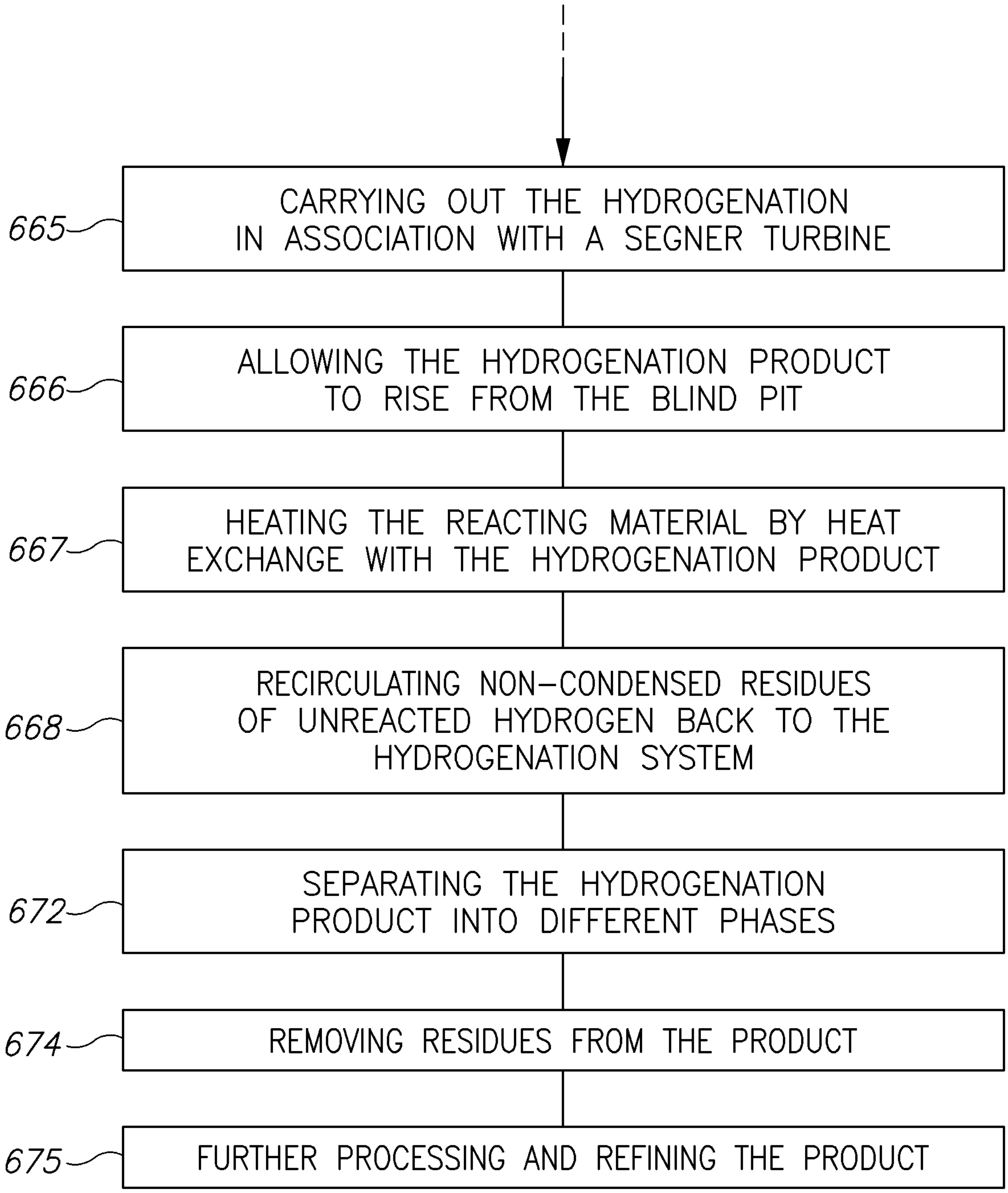

Figure 11B (cont. 3)