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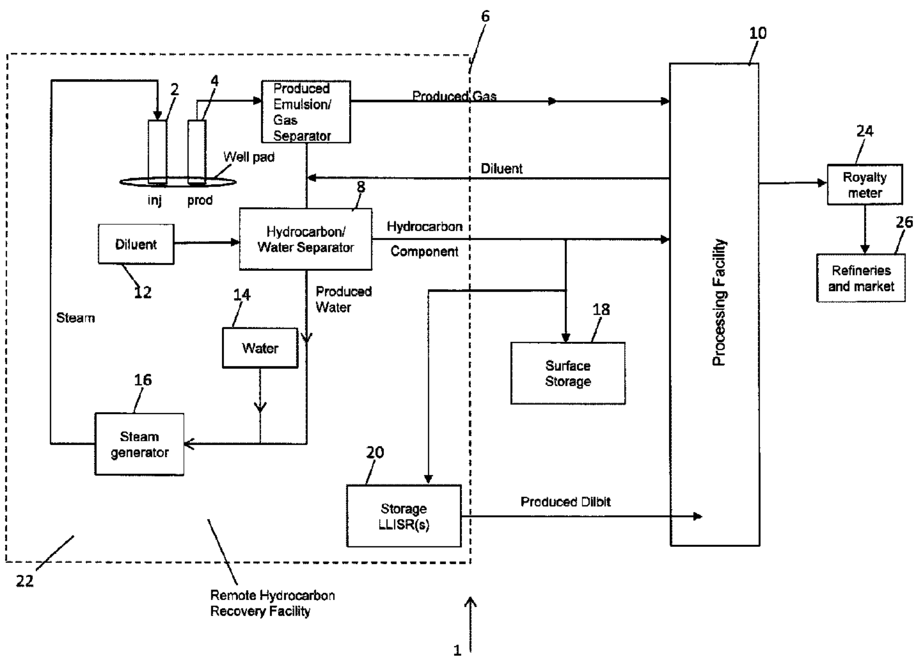
(72) **Inventeurs/Inventors:**
BEENTJES, IVAN, CA;
MCMINN, NEIL ALAN, CA;
GLOVER, ROBERT DANIEL, CA

(73) **Propriétaire/Owner:**
SUNCOR ENERGY INC., CA

(74) **Agent:** CPST INTELLECTUAL PROPERTY INC.

(54) **Titre : SYSTEME ET METHODE POUR STOCKER DU BITUME DILUE EN FIN DE VIE DANS LES RESERVOIRS SUR PLACE**
(54) **Title: SYSTEM AND METHOD FOR STORING DILUTED BITUMEN IN LATE LIFE IN SITU RESERVOIRS**



(57) **Abrégé/Abstract:**
Provided herein are systems and methods for storing hydrocarbons, such as diluted bitumen, in late life in situ reservoirs (LLISRs). One of such methods comprises injecting hydrocarbons into an LLISR to establish a quantity of stored hydrocarbons in the LLISR, and producing back at least a portion of the stored quantity. Permanent loss of hydrocarbons into the LLISR can be reduced by minimizing the time between injection and production. Containment of hydrocarbons in the LLISR can be improved by performing multiple consecutive injection/production cycles due to progressive saturation of so-called far field areas of the LLISR. When storing diluted bitumen, controlling LLISR pressure can be important to minimize vaporization of diluent from dilbit stored in the LLISR.

ABSTRACT

Provided herein are systems and methods for storing hydrocarbons, such as diluted bitumen, in late life in situ reservoirs (LLISRs). One of such methods comprises injecting hydrocarbons into an LLISR to establish a quantity of stored hydrocarbons in the LLISR, and producing back at least a portion of the stored quantity. Permanent loss of hydrocarbons into the LLISR can be reduced by minimizing the time between injection and production. Containment of hydrocarbons in the LLISR can be improved by performing multiple consecutive injection/production cycles due to progressive saturation of so-called far field areas of the LLISR. When storing diluted bitumen, controlling LLISR pressure can be important to minimize vaporization of diluent from dilbit stored in the LLISR.

SYSTEM AND METHOD FOR STORING DILUTED BITUMEN IN LATE LIFE IN SITU RESERVOIRS

TECHNICAL FIELD

[0001] The following generally relates to the storage of hydrocarbons, particularly to the storage of hydrocarbons in late life in situ reservoirs (LLISRs).

BACKGROUND

[0002] Oil sands are a natural mix of sand, clay, water, and bitumen. Bitumen is considerably viscous and does not flow like conventional crude oil. As such, bitumen is recovered from oil sands using either surface mining techniques or in situ techniques. In surface mining, overburden is removed to access the underlying bitumen reservoir, and the oil sands are transported to an extraction facility to separate the bitumen from the other components of the oil sands (i.e. tailings). For in situ techniques, the bitumen reservoir is heated and the bitumen within flows into one or more horizontal production wells, leaving the formation rock in the bitumen reservoir in place. In such techniques, the bitumen in the bitumen reservoir is often emulsified to enhance recovery. Both surface mining and in situ processes produce a bitumen product that is subsequently sent to an upgrading and/or refining facility, to be refined into one or more petroleum products.

[0003] Bitumen reservoirs that are too deep to feasibly permit bitumen recovery by mining techniques are typically accessed by drilling wellbores into the bitumen reservoir and implementing an in situ technology. There are various in situ technologies available that use thermal methods to liberate bitumen from the reservoir with heated fluids, e.g., steam, hydrocarbon solvent vapour, or steam and solvent in combination. In many conventional thermal in situ techniques, the heated fluids can be injected into the reservoir. However, in newer techniques, e.g., electric resistive heating, EM radio frequency, and induction, heated fluids can be generated from fluids present in the reservoir.

[0004] Common in situ techniques include Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS). In SAGD, a pair of horizontally oriented wells are drilled into the bitumen reservoir, such that the pair of horizontal wells are vertically aligned with respect to each other and separated by a relatively small distance, typically in the order of several meters. The well installed closer to the surface and above the other well is generally referred to as an injection well, and the well positioned below the injection well is referred to as a production well. The injection well and the production well are then connected to various subsurface equipment, such as electric submersible pumps (ESPs) and sensors, and to equipment installed at a surface site. The injection well facilitates steam injection into the reservoir. The injected steam propagates vertically and laterally into the reservoir to develop what is referred to as a steam chamber. Latent heat released by the injected steam mobilizes the bitumen by lowering its viscosity. The bitumen, in turn, drains due to gravity and is produced, along with condensed water, by the production well.

[0005] In CSS, a single, vertical, production/injection well extending into a bitumen reservoir can be used for both steam injection and production. CSS typically involves three main phases, namely an injection phase, a shut in phase, and a production phase. During the injection phase, steam is injected through the production/injection well into the bitumen reservoir. Next, the bitumen reservoir is shut in to allow heat from the steam to reduce the viscosity of the bitumen in the reservoir. The bitumen of reduced viscosity can then be produced through the production/injection well, and the three phase cycle can be repeated.

[0006] Produced bitumen typically has a considerably high viscosity and thus can be difficult to transport via pipeline. To overcome this issue, the viscosity of bitumen can be decreased by, for example, partial upgrading or dilution with light hydrocarbons such as naphtha and pentane (i.e., diluent). Diluted bitumen is commonly referred to as "dilbit".

[0007] During periods of production curtailment or other imposed restrictions or reductions, a limit is typically placed on dilbit production. In the absence of sufficient storage, it is often the case that bitumen production must significantly slow down or even stop at some point during such a curtailment period. When the curtailment period is over, it can be difficult to compensate for the financial losses incurred from not producing at full capacity.

[0008] Additionally, it is known that bitumen prices tend to decrease during the winter and increase during the summer. In response to these price fluctuations, methods have been developed for storing a portion of produced dilbit during the winter to be sold to the market in the summer. However, these methods can be limited by availability, size and economics.

[0009] Moreover, bitumen production facilities may take extended shutdowns for maintenance activities which cannot be carried out during operation. These extended maintenance or turnaround activities typically occur over a period of several weeks and can decrease upgrading and/or pipeline capacity. This, in turn, can limit bitumen production.

[0010] It would be advantageous to develop a method for storing dilbit that addresses at least one of the above noted issues or disadvantages.

SUMMARY

[0011] Provided herein are systems and methods for storing hydrocarbons, such as diluted bitumen, in late life in situ reservoirs (LLISRs). One of such methods comprises injecting hydrocarbons into an LLISR to establish a quantity of stored hydrocarbons in the LLISR, and producing back at least a portion of the stored hydrocarbons. Permanent loss of hydrocarbons into the LLISR can be reduced by minimizing the time between injection and production. Containment of hydrocarbons in the LLISR can be improved by performing multiple consecutive injection/production cycles due to progressive saturation of so-called far field areas of the LLISR. When storing diluted bitumen, controlling LLISR pressure can be important to minimize vaporization of diluent from dilbit stored in the LLISR.

[0012] In one aspect, provided herein is a method of temporarily storing hydrocarbons in a thermal, late life, in situ reservoir (LLISR), the method comprising: delivering hydrocarbons into the LLISR to establish a quantity of stored hydrocarbons in the LLISR; and producing at least a portion of the stored hydrocarbons from the LLISR to recover a quantity of produced hydrocarbons.

[0013] In an implementation of the method, the hydrocarbons are delivered into the LLISR once the LLISR has cooled to a pre-determined temperature.

[0014] In another implementation of the method, the stored hydrocarbons are produced immediately after the hydrocarbons are delivered into the LLISR.

[0015] In yet another implementation of the method, the quantity of produced hydrocarbons is less than the quantity of stored hydrocarbons delivered into the LLISR.

[0016] In yet another implementation, the method further comprises delivering additional hydrocarbons into the LLISR to increase the quantity of stored hydrocarbons remaining in the LLISR; and producing at least a portion of the stored hydrocarbons to recover another quantity of produced hydrocarbons.

[0017] In yet another implementation, the method further comprises repeating at least once the steps of delivering additional hydrocarbons into the LLISR to increase the quantity of stored hydrocarbons remaining in the LLISR; and producing at least a portion of the stored hydrocarbons to recover another quantity of produced hydrocarbons.

[0018] In yet another implementation, the method further comprises removing contaminants from the produced hydrocarbons.

[0019] In yet another implementation of the method, the contaminants comprise one or more of chlorides, solids, and water.

[0020] In yet another implementation of the method, the hydrocarbons are delivered into the LLISR by injection through a first well.

[0021] In yet another implementation of the method, at least some of the produced hydrocarbons are produced by the first well.

[0022] In yet another implementation of the method, at least some of the produced hydrocarbons are produced by a second well.

[0023] In yet another implementation of the method, a second well controls LLISR pressure by injecting an injection fluid into the LLISR.

[0024] In yet another implementation of the method, a third well provided in the LLISR controls LLISR pressure by injecting an injection fluid into the LLISR.

[0025] In yet another implementation of the method, the injection fluid creates a gas push from the second well in the direction of the first well.

[0026] In yet another implementation of the method, the injection fluid creates a gas push from the third well in the direction of the first and second wells.

[0027] In yet another implementation of the method, LLISR pressure is controlled at least in part by the second well to be approximately equal to a pressure in a nearby reservoir undergoing a thermal recovery process.

[0028] In yet another implementation of the method, LLISR pressure is controlled at least in part by the third well to be approximately equal to a pressure in a nearby reservoir undergoing a thermal recovery process.

[0029] In yet another implementation of the method, the first well is positioned in a relatively warmer region of the LLISR, and the second well is positioned in a relatively colder region of the LLISR, the warmer region being closer in proximity to the reservoir than the colder region.

[0030] In yet another implementation of the method, the first well is positioned in a relatively warmer region of the LLISR, the third well is positioned in a relatively colder region of the LLISR, the warmer region being closer in proximity to the reservoir than the colder region, and the second well is positioned intermediate the first and third wells.

[0031] In yet another implementation, the method further comprises producing through at least one other well, hydrocarbons positioned at the edge of or lost from the stored quantity, and returning the hydrocarbons to the LLISR through the first well.

[0032] In yet another implementation of the method, the at least one other well is an infill well.

[0033] In yet another implementation of the method, the hydrocarbons comprise diluted bitumen, the diluted bitumen comprising bitumen and a diluent.

[0034] In yet another implementation of the method, the diluent comprises a C_2-C_{12} alkane, C_2-C_{12} alkene, C_3-C_{12} cycloalkane, C_3-C_{12} aromatic, or a combination thereof.

[0035] In yet another implementation of the method, the diluent comprises natural-gas condensates.

[0036] In yet another implementation of the method, the diluent comprises naphtha.

[0037] In yet another implementation of the method, LLISR pressure is controlled to limit vaporization of the diluent.

[0038] In yet another implementation of the method, the injection fluid has a molecular weight similar to a molecular weight of the diluent.

[0039] In yet another implementation of the method, the injection fluid comprises steam, naphtha, a C_2-C_{12} alkane, C_2-C_{12} alkene, C_3-C_{12} cycloalkane, C_3-C_{12} aromatic, or a combination thereof.

[0040] In yet another implementation, the injection fluid comprises a non-condensable gas (NCG). The NCG can comprise at least one of N_2, CO_2, or methane.

[0041] In yet another implementation the LLISR has been subjected to a steam assisted gravity drainage (SAGD), expanding solvent SAGD (ES-SAGD), or thermal solvent recovery process, prior to delivering the diluted bitumen into the LLISR.

[0042] In another aspect, the hydrocarbons being stored comprise diluted bitumen comprising bitumen and a diluent, and the method further comprises controlling pressure in the LLISR to limit vaporization of the diluent while delivering the diluted bitumen to, and/or while producing the stored diluted bitumen from, the LLISR.

[0043] In yet another aspect, provided is a system for storing hydrocarbons in a thermal, late life, in situ reservoir (LLISR), the system comprising: the LLISR; a source of the hydrocarbons; and a first well for injecting the hydrocarbons into the LLISR.

[0044] In an implementation, the system further comprises a reservoir undergoing a thermal recovery process, the reservoir being near the LLISR.

[0045] In another implementation, the system further comprises a second well for producing stored hydrocarbons from the LLISR and/or for pressure maintenance.

[0046] In yet another implementation, the system comprises a third well for producing stored hydrocarbons from the LLISR and/or for pressure maintenance.

[0047] In yet another implementation of the system, the second well is configured to control LLISR pressure by injecting an injection fluid.

[0048] In yet another implementation of the system, the third well is configured to control LLISR pressure by injecting an injection fluid.

[0049] In yet another implementation of the system, the first well is positioned in a relatively warmer region of the LLISR, and the second well is positioned in a relatively colder region of the LLISR, the warmer region being closer in proximity to the reservoir than the colder region.

[0050] In yet another implementation of the system, the first well is positioned in a relatively warmer region of the LLISR, the third well is positioned in a relatively colder region of the LLISR, the warmer region being closer in proximity to the reservoir than the colder region, and the second well is positioned intermediate the first and third wells.

[0051] In yet another implementation, the system further comprises at least one infill well for producing hydrocarbons.

[0052] In yet another implementation of the system, the hydrocarbons and the stored hydrocarbons comprise diluted bitumen, the diluted bitumen comprising bitumen and a diluent.

[0053] In yet another implementation of the system, the diluent comprises a C_2-C_{12} alkane, C_2-C_{12} alkene, C_3-C_{12} cycloalkane, C_3-C_{12} aromatic, or a combination thereof.

[0054] In yet another implementation of the system, the diluent comprises natural-gas condensates.

[0055] In yet another implementation of the system, the diluent comprises naphtha.

[0056] In yet another implementation of the system, the injection fluid has a molecular weight similar to a molecular weight of the diluent.

[0057] In yet another implementation of the system, the injection fluid comprises steam, naphtha, a C_2-C_{12} alkane, C_2-C_{12} alkene, C_3-C_{12} cycloalkane, C_3-C_{12} aromatic, or a combination thereof.

[0058] In yet another implementation, the injection fluid comprises a non-condensable gas (NCG). The NCG can comprise at least one of N_2, CO_2, or methane.

[0059] In yet another implementation of the system, the source of hydrocarbons is an in situ hydrocarbon recovery facility.

[0060] In yet another implementation, the system further comprises injection equipment configured to deliver the hydrocarbons into the LLISR once the LLISR has cooled to a pre-determined temperature.

[0061] In yet another implementation, the second well is configured to produce the stored hydrocarbons immediately after the hydrocarbons are delivered into the LLISR.

[0062] In yet another implementation, the quantity of produced hydrocarbons produced from the second well is less than the quantity of stored hydrocarbons delivered into the LLISR.

[0063] In yet another implementation, the system further comprises equipment to remove contaminants from the produced hydrocarbons. The contaminants can comprise one or more of chlorides, solids, and water.

[0064] In yet another implementation, the LLISR has been subjected to a steam assisted gravity drainage (SAGD), expanding solvent SAGD (ES-SAGD), or thermal solvent recovery process, prior to delivering the diluted bitumen into the LLISR.

BRIEF DESCRIPTION OF THE DRAWINGS

[0065] Embodiments will now be described with reference to the appended drawings wherein:

[0066] FIG. 1 is a system for producing, storing and shipping hydrocarbons, the system including storage LLISRs.

[0067] FIG. 2 is a flow chart illustrating a method for operating the storage aspects of the system shown in FIG. 1.

[0068] FIG. 3 is a schematic plan view of a number of SAGD well pads under which are located late life SAGD reservoirs ("LLISRs").

[0069] FIG. 4 is a schematic cross-sectional view of the LLISRs shown in FIG. 3.

[0070] FIG. 5 is a schematic cross-sectional view of another set of LLISRs.

[0071] FIG. 6 is a flow chart illustrating a method for storing dilbit in an LLISR.

[0072] FIG. 7 is a flow chart illustrating a method for controlling pressure in an LLISR.

[0073] FIG. 8 is a schematic cross-sectional view of a system for storing diluted bitumen ("dilbit") in LLISRs near an active SAGD steam chamber.

[0074] FIG. 9 is a flow chart illustrating a method for increasing the efficiency of storing dilbit in an LLISR.

[0075] FIG. 10A is a schematic cross-sectional view of the system shown in FIG. 8 after a dilbit injection cycle has been completed.

[0076] FIG. 10B is a schematic cross-sectional view of the system shown in FIGS. 8 and 10A after a production cycle in which a portion of the stored dilbit has been produced.

DETAILED DESCRIPTION

[0077] Bitumen and heavy oil are naturally occurring petroleum materials characterized by high density and high viscosity. Although bitumen is typically heavier and more viscous than heavy oil, both have a viscosity normally found to be too high for pipeline transportation at ambient temperature. It will be understood that the term "dilbit" as used herein refers to diluted bitumen and diluted heavy oil. Accordingly, the term "bitumen" as used herein refers to bitumen and heavy oil, which can also be collectively referred to as heavy hydrocarbons.

[0078] It will be understood that the term "LLISR" as used herein can mean any hydrocarbon bearing reservoir having a hydrocarbon depleted zone therein formed from a thermal recovery process. Accordingly, when it is stated that a fluid is stored in, injected into, or produced from an LLISR, it will be understood that such fluid is stored in, injected into, or produced from the hydrocarbon depleted pay zone (i.e., storage volume) in the LLISR. Accessing and utilizing this often considerably large storage volume could mitigate lost profits incurred by production curtailments, seasonal hydrocarbon price fluctuations and storage limitations in general.

[0079] The term "injection fluids" as used herein will be understood to mean fluids used to mobilize bitumen during thermal recovery processes. Such injection fluids can be, for example, steam or vaporized solvent.

[0080] The term "pressure control fluids" as used herein will be understood to refer to fluids that are injected into subsurface formations for the purposes of, e.g., pressure control or controlling hydrocarbon movement within and/or between reservoirs. Pressure control fluids can be, for example, non-condensable gases (e.g., CO_2, methane, N_2) or vaporized condensable gases (e.g., naphtha, pentane).

[0081] The following specification discusses storing dilbit in LLISRs; however, it can be appreciated that the methods and systems discussed herein can be used to store and produce back other hydrocarbons having suitable physical properties in LLISRs, such as, for example, synthetic crude oil. To be deemed suitable, the hydrocarbons are light enough (i.e., of low enough viscosity) to not require a thermal process for the hydrocarbons to be injected into or produced back from the LLISR. The hydrocarbons are also sufficiently heavy so as to not evaporate at common LLISR temperatures and pressures associated therewith (and attainable pressures). As explained in greater detail below, LLISR pressure can be increased to reduce such evaporation. Another hydrocarbon that can be stored in an LLISR is, e.g., synthetic crude oil.

[0082] Depicted in FIG. 1 is an example embodiment of a system 1 similar to that commonly seen in the Canadian oil sands for producing, treating, storing and transporting bitumen. However, in this example, the system 1 has been modified to mitigate storage limitations by incorporating at least one LLISR 20 into the system 1. The system 1 comprises an injection well 2 and a production well 4 which can produce bitumen/water emulsion and gas. A separator 6 can be positioned downstream of the production well 4 and functions to separate the produced gas from the produced emulsion. From the separator 6, which is typically located in a remote hydrocarbon recovery facility 22, the produced gas can be conveyed to a processing facility 10 such as a central processing facility (CPF), if online and available, or other pad size processing equipment, which can be connected to a number of other remote hydrocarbon recovery facilities. The produced emulsion from the separator 6 can be fed into a second separator 8 which separates the produced emulsion into produced water and a produced hydrocarbon component. The second separator 8 can include, for example, a free water knockout tank (FWKO) and a treater, or can be a high temperature separator. Diluent can be added upstream of the second separator 8 and/or within the second separator 8 to facilitate the isolation and subsequent transportation to the processing facility 10 of the hydrocarbon component (in this case, bitumen), by decreasing its density and viscosity.

[0083] The produced water from the second separator 8 can be sent to a steam generator 16, and optionally combined with additional water from a water source 14 (e.g., a tank, well or other source) located at the hydrocarbon recovery facility 22. The steam generator 16 can be part of a water treatment system wherein the produced water is further de-oiled prior to being fed through, for example, a direct or indirect fired steam generator. The generated steam can be sent to the injection well 2 to be injected into a bitumen containing formation.

[0084] After the second separator 8, the hydrocarbon component can include dilbit. From the second separator 8, the dilbit can be conveyed to the processing facility 10, surface storage and/or salt caverns 18 or the storage LLISR(s) 20. In the processing facility 10, the dilbit can be treated to remove contaminants such as those listed above. As noted above, hydrocarbon production can be quantified using what is referred to as a royalty meter 24, often positioned downstream of the processing facility 10 and between the processing facility 10 and the market 26. Produced dilbit can be diverted to storage prior to reaching the processing facility 10, or from the processing facility 10 before reaching the royalty meter 24 (not shown). In this case, dilbit production does not need to be quantified by the royalty meter 24 at this time, thereby avoiding lost profits and penalties incurred by, for example, selling dilbit at discount and overproducing during periods of curtailment, respectively. It can be appreciated that dilbit that has already passed the royalty meter 24 can also be accepted by the LLISR(s) if necessary. As indicated above, it can also be appreciated that the processing facility 10 need not apply to a single main CPF but could be an additional facility used in the event the main CPF is down for, e.g., repairs.

[0085] FIG. 2 is a flow chart illustrating a method for operating the system 1 illustrated in FIG. 1. Specifically, the flow chart provides a method of handling the produced bitumen between the second separator 8 and the refineries and market 26. Although discussed with respect to the system 1, it will be appreciated that the following method can be applied in any hydrocarbon production and storage system having LLISRs 20 suitable for storage. Characteristics that make an LLISR 20 suitable for storage are discussed further below with respect to FIGS. 4 and 5.

[0086] Continuing with FIG. 2, at step 30, the hydrocarbon component (dilbit, in this instance) is obtained from the separator 8. Next, at step 32, it is determined whether to store the dilbit. For example, if the winter season is approaching and a price decrease is expected, or if production curtailments are in effect, a decision can be made to store the dilbit and the method moves to step 36. If it is determined to not store the dilbit, the method proceeds to step 34, wherein the dilbit can be sent to the processing facility 10 to be treated and transported. At step 36, the available storage using conventional options such as surface storage tanks and/or salt caverns is determined and, if sufficient space remains, the method proceeds to step 38, wherein the dilbit can be conveyed to the processing facility 10 to be treated and stored using such conventional options. If sufficient space does not remain in surface tanks and/or salt caverns 18, the method proceeds to step 40 wherein the dilbit is injected into one of the storage LLISRs 20. At step 42 of the method, the dilbit remains in the LLISRs 20 until it is desirable to produce back the dilbit. At this point, the method proceeds to step 44 and a dilbit/water emulsion is produced. Next, at step 46, the produced dilbit/water emulsion can be separated into produced water and dilbit. The dilbit obtained at step 46 is treated at step 48 by an appropriately sized treater to remove impurities such as chlorides and solids. The required size of such a treater can be determined in advance of implementing storage in LLISRs 20 by conducting an economic analysis and/or reservoir simulation to approximate the amount of dilbit that would be stored in the LLISRs and what portion of the dilbit stored in the LLISRs 20 could permanently remain therein (i.e., after storage). After treatment, at step 50, diluent can be added to or removed from the dilbit to meet pipeline specifications for transportation to the market at step 52.

[0087] As mentioned, it can be desirable to utilize LLISRs 20 that can contain dilbit such that all or most of the dilbit can be produced back after being stored. For example, a good LLISR 20 for storage can have pre-existing SAGD wells positioned in a permeability trap (see, e.g., FIGS. 8A-8D). Known methods such as 4-D seismic, observation well measurements and/or reservoir simulations can be used to predict and measure the movement of fluids in an LLISR 20, and thus can aid in selecting LLISRs suitable for dilbit storage. Other characteristics of the LLISRs 20 such as maximum operating pressure (MOP) can be known and can contribute to the selection of a storage LLISR 20 for reasons discussed further below.

[0088] FIG. 3 illustrates part of an oil field 100 having a number of LLISRs 102a, 102b and 102c, collectively referred to hereinafter with reference character 102. The LLISRs 102 typically include a number of geological materials such as a rock matrix, sand, clays and any bitumen not recovered when the LLISRs 102 underwent thermal recovery processes. As shown in greater detail in FIG. 4, the oil field 100 can include an impermeable feature 104, such as a mud filled channel, which can create what is known as a stratigraphic hydrocarbon trap. The impermeable feature 104 can substantially prevent lateral migration of hydrocarbons therethrough. As shown, well pads 106a, 106b and 106c, collectively referred to as well pads 106, are positioned on the surface of the oil field 100. Well pads 106a, 106b and 106c (well pads 106, collectively) can each have at least one SAGD production/injection well pair 108a, 108b and 108c (well pairs 108, collectively), respectively, positioned thereon. These well pairs 108 can be those that were used to deplete the LLISRs 102 of bitumen by way of, for example, a SAGD process carried out earlier in the life of the LLISRs 102.

[0089] It can be appreciated that the impermeable feature 104 can alternatively be a granite formation, a shale layer, a salt dome, or another known impermeable geological feature. It can also be appreciated that the storage volume can be completely encircled by impermeable geological features. Additionally, artificial isolation barriers, which can be made by, e.g., injecting cement and/or clays, can be used alone or in combination with one or more of the above impermeable features to improve dilbit containment. The example described with respect to FIG. 4 provides various examples of LLISRs each having different geological features that can be conducive to hydrocarbon containment.

[0090] FIG. 4 is a schematic cross-sectional view of the LLISRs 102 exemplified in FIG. 3. The LLISRs 102 are overlain by overburden 110 which is beneath the surface 109. The overburden 110 includes a caprock 112, which can be impermeable to injection fluids and pressure control fluids. In this example embodiment, the LLISRs 102b and 102c are each the result of anticline structural traps formed by the caprock 112, and the LLISR 102a is the result of an anticline structural trap and a stratigraphic trap. Horizontal production wells 109a, 109b and 109c extend into bitumen LLISRs 102a, 102b and 102c, respectively. The production wells 109a, 109b and 109c have corresponding horizontal injection wells 108a, 108b and 108c, respectively. In the example shown in FIG. 4, a bottom water layer 115 underlies the bitumen LLISRs 102. Beneath the bottom water layer 115 in this example is an underlying formation 114 which can be, for example, source rock. The LLISRs 102 can contain void space into which a fluid such as dilbit can be injected. In many cases, such void space exists because as bitumen was produced from the LLISRs 102, steam and/or vaporized solvent, depending on the injection fluid used in the thermal recovery process, at least partially replaced the pore space previously occupied by the bitumen within the porous reservoir rock. For example, as the steam and/or vaporized solvent condensed, a substantial portion of the LLISRs' porosity may have become void space (i.e., space that is available for storage).

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[0091] From a thermodynamic model, it was determined that the viscosity of dilbit at a low temperature (e.g., 50ºC) can have a viscosity similar to mobilized SAGD bitumen (which is much hotter). Thus, the viscosity of stored dilbit is unlikely to be a limiting factor during back production (i.e., production of the stored dilbit). However, as noted above, dilbit comprises diluent which can vaporize and thereby exit the dilbit at temperatures commonly seen in LLISRs 20, 102 if pressure is not kept sufficiently high.

[0092] Further, simulations showed that in some reservoirs, unproduced bitumen can be converted to dilbit by injected dilbit. In such LLISRs, vaporized diluent from the dilbit can mobilize into and mix with the unproduced bitumen, thereby converting the bitumen to dilbit. However, since diluent is considered more valuable than dilbit, it is generally undesirable to lose vaporized diluent to the LLISR, even though additional dilbit can be produced as a function of vaporized diluent. That is, the simulations suggest that the production of new dilbit as a function of vaporized diluent may not be sufficient to compensate for the capital losses incurred by the vaporization (and loss) of diluent. Accordingly, pressure maintenance within the LLISRs 20, 102 to limit diluent vaporization can be important. A general method for pressure maintenance is shown in FIG. 7 and described further below.

[0093] To increase and/or maintain reservoir pressure, NCGs such as CO_2, N_2, and/or methane can be injected into an LLISR 20, 102. A vaporized diluent, such as naphtha, can be injected alone or in combination with NCGs to maintain pressure and to increase the amount of liquid diluent in the dilbit. Steam can also be considered for pressure control. Optionally, one or more vertical wells can assist in pressure control by injecting water into the LLISR 20, 102 at a point below the stored dilbit thereby creating what is known as a water drive. Injecting pressure control fluids of similar molecular weight to the diluent can limit vaporization of the diluent from the dilbit by constraining the partial pressure of the diluent. For example, a pressure control fluid comprising butane can be injected when the diluent in the dilbit comprises cyclohexane, thereby reducing vaporization of the cyclohexane.

[0094] Returning to FIG. 4, the LLISRs 102a and 102b can store dilbit injected through the production wells 109a and 109b, respectively. In the example embodiment shown, dilbit is not being injected into the reservoir 102c. The reservoir 102c can assist in pressure maintenance of the reservoir 102b by way of pressure control fluid (e.g., NCG) injection through the injection well 108c. Dilbit injected through the production well 109b can migrate into the reservoir 102c and NCGs injected through the injection well 108c can migrate into the reservoir 102b, depending on the pressure gradient therebetween.

[0095] The injection well 108a can inject NCGs into the LLISR 102a to control the pressure of the LLISR 102a. Optionally, a vertical well 113 can extend through the LLISR 102a into the bottom water layer 115. As previously noted, injection of water into the bottom water layer 115 can be initiated and/or adjusted to help control the pressure of the LLISR 102a. The impermeable feature 104 can prevent migration of injection fluids, pressure control fluids and dilbit between the LLISR 102a and 102b.

[0096] When desirable, the production wells 109a and 109b can produce back stored dilbit from the LLISRs 102a and 102b. Pumps such as ESPs, progressive cavity pumps ("PCPs"), electric submersible progressive cavity pumps ("ESPCPs"), or other lift mechanisms can be employed during back production. As dilbit is produced, one or more of the injection wells 108a, 108b and 108c can inject NCGs to control pressure. As noted above, the vertical well 113 can optionally be provided to create a water drive to increase pressure in reservoir 102a. If dilbit migrates into the reservoir 102c, the dilbit therein can be produced through the production well 109c.

[0097] FIG. 5 illustrates another example embodiment of an LLISR 203 that can be suitable for storing dilbit. The LLISR 203 is similar to those often seen in the Canadian oil sands. The LLISR 203 includes a porous storage space within a surrounding formation 202. The surrounding formation 202 can contain unproduced bitumen and/or one or more materials that can serve as a barrier to dilbit. The LLISR 203 can be substantially bitumen depleted as a result of a thermal recovery process and can contain residual heat from an injection chamber formed during the thermal recovery process. An example of an injection chamber is a steam chamber developed during a SAGD process. A caprock 212, which is part of an overburden 210, can overlie the LLISR 203. An underlying formation 210 can be situated below the surrounding formation 202.

[0098] Injection wells 208a, 208b and 208c (injection wells 208, collectively) and production wells 209a, 209b and 209c (production wells 209, collectively) can be positioned within the LLISR 203. These injection wells 208 and/or production wells 209 can optionally be those used previously used to carry out the thermal recovery process, in which case the drilling of new wells can be avoided or reduced, decreasing capital costs. One or both of the injection wells 208a and 208c can be configured to inject one or more pressure control fluids, such as, e.g., NCGs, into the LLISR 203, and the production well 209b can be configured to produce back dilbit. The injection well 208b can be configured to inject dilbit into the LLISR 203. One or both of the outer production wells 209a and 209c can be used to produce dilbit and/or cycle dilbit back to the

LLISR 203 via the injection well 208b, thereby controlling migration of the dilbit pile formed in the LLISR 203 (discussed in greater detail below). It can also be appreciated that one or both of the outer injection wells 208a and 208c can, by way of pressure control fluid injection, push dilbit toward the production well 209b.

[0099] It can be appreciated that well configurations other than those described in the above examples can be used to inject and produce dilbit, to inject pressure control fluids, and to control dilbit migration (by, e.g., dilbit cycling and/or targeted pressure control fluid injection). For example, a first well provided in an LLISR 20, 102, 203 can be used as both a dilbit injection and production well. Optionally, a second well can be provided for pressure maintenance. Alternatively, a first well can be used for injecting dilbit, and a second well can be used for producing back the stored dilbit. At least one other well can inject injection fluids, e.g., NCGs to control pressure and/or dilbit migration in the LLISR 20, 102, 203. Furthermore, it can be appreciated that one or more infill wells can be included to cycle the dilbit from the edge of the dilbit pile back into the LLISR 20, 102, 203 through the first well.

[00100] FIG. 6 depicts a flow chart of a method for storing dilbit in an LLISR 20, 102, 203. The method begins at step 504, where a desired amount of dilbit can be injected. When the desired amount of dilbit has been injected into the LLISR 20, 102, 203, injection stops (step 506). Optionally, the method can be controlled to begin only once the LLISR 20, 102, 203 reaches a target temperature (i.e., has sufficiently cooled). Such a target temperature can be determined by, e.g., carrying out simulations of storing dilbit in the subject LLISR 20, 102, 203. The target temperature could be, for example, a temperature low enough that an LLISR 20, 102, 203 pressure can be achieved that can minimize diluent vaporization while remaining below maximum operation pressure (MOP). At step 508, it is determined whether a delay before back production is required. If yes, production can be delayed until back production is desirable (step 510). If no, production can begin immediately (step 512) until a desired amount of dilbit is produced, at which point the method proceeds to step 514 where production can be stopped. It is then determined whether it is desirable to inject more dilbit (i.e., start another cycle), or to shut in the LLISR 20, 102, 203 (step 516). If so, the method can proceed to step 504 wherein dilbit injection can be restarted. If not, the LLISR 20, 102, 203 can be shut in (step 518). Throughout the method, reservoir pressure can be controlled by injecting, e.g., NCGs, to reduce vaporization of diluent from the dilbit (FIG. 7). Dilbit migration can also be monitored and controlled by way of targeted pressure control fluid injection and/or dilbit cycling, as discussed above.

[00101] FIG. 7 depicts a flow chart illustrating a general method for managing pressure in an LLISR 20, 102, 203 while dilbit is stored therein. The method begins at step 705, wherein pressure and temperature of the LLISR 20, 102, 203 are measured. The method then proceeds to step 710 wherein the measured pressure is compared to a known pressure of vaporization of diluent from dilbit ("vaporization pressure") at the measured temperature. Pressure and temperature can be measured along an instrumented wellbore through which pressure control fluids can be injected. Pressure and temperature can also be measured along an instrumented wellbore through which dilbit is being injected and/or produced. If the measured pressure is below the vaporization pressure at the measured temperature, the method proceeds to step 715, wherein reservoir pressure can be increased by increasing or starting pressure control fluid (e.g., NCG) injection. It can be appreciated that reservoir pressure can be increased (or decreased as required below) in other ways known to those skilled in the art such as, e.g., using bottom water drive. The method then returns to step 705 and begins again. If, at step 710, the measured pressure is not below the diluent vaporization pressure at the measured temperature, the method can proceed to step 720, where it is determined whether the reservoir pressure is below the MOP. If the reservoir pressure is below the MOP, the method can proceed to step 725 where NCG injection can be decreased to decrease the reservoir pressure, and the method can return to step 705. If, at step 720, it is found that the pressure is below the MOP at the measured temperature, the method can return to step 705. It can be appreciated that the "vaporization pressure" can also be a pressure at which a maximum permissible rate of diluent vaporization can occur (can be determined from, e.g., simulations and/or pilot data, combined with economic analysis).

[00102] An assumption, or starting condition for the method illustrated in FIG. 7 can be that the temperature in the LLISR 20, 102, 203 is sufficiently low (i.e., the LLISR 20, 102, 203 has been allowed to cool for long enough) that any pressure below the diluent vaporization pressure at the measured temperature is lower than the MOP of the subject LLISR 20, 102, 203.

[00103] FIG. 8 illustrates an example embodiment of an LLISR 303 that can be used for storing dilbit. Like the LLISR 203 discussed above, the LLISR 303 shown in FIG. 8 is a porous storage space within a surrounding formation 302. The surrounding formation 302 can contain unproduced bitumen and/or one or more materials that serve as a barrier to dilbit. However, in this example embodiment, an active SAGD steam chamber 305 is present within the surrounding formation 302, and near the LLISR 303. As a result, the surrounding formation 302 can have a warmer zone 302a and a colder zone 302b. It can be important to control the pressure in the LLISR 303 to prevent migration of steam from the steam chamber 305 into the storage space 303, or of stored hydrocarbons and/or pressure control fluids from the storage space 303 into the steam chamber 305. As will be appreciated, the steam chamber 305 can be a different active injection chamber, such as an injection chamber containing vaporized solvent.

[00104] Simulations have shown that areas in close proximity to wells injecting pressure maintenance gases can cool relatively quickly. Thus, it can important to control injection rates to avoid LLISR overcooling. Moreover, positioning one or more pressure maintenance wells to inject gas near the warmer bitumen zone 302a (and near the steam chamber 305) can cause cooling in the warmer bitumen zone 203a.. This, in turn, can reduce the energy efficiency of the hydrocarbon recovery process with which the steam chamber 305 (or a solvent chamber) is associated. The hydrocarbon recovery process can comprise, for example, SAGD, expanding solvent SAGD (ES-SAGD), and solvent-based recovery processes. Positioning pressure maintenance wells near the colder bitumen zone 302b can mitigate heat loss from the steam chamber 305 by acting as a buffer between the zones 302a, 302b. Moreover, such a configuration can enable a more efficient gas push, since colder bitumen can be a more effective barrier than warmer bitumen to pressure control fluids. It will be appreciated, however, that if the steam chamber 305 and the LLISR 303 are in fluid communication, positioning a pressure maintenance well relatively near the point of communication may be implemented to limit steam ingress.

[00105] It can be appreciated that the above principles can be applied in other LLISRs, such as, e.g., LLISRs (not shown) that are close to more than one injection chamber containing steam and/or solvent.

[00106] Continuing with FIG. 8, three injection wells 308a, 308b and 308c, and three production wells 309a, 309b, and 309c are provided in the LLISR 303. The injection well 308a and the production well 309a can optionally be shut in. The injection well 308b can be utilized to inject dilbit into the LLISR 303, and the production well 309b can be utilized to produce dilbit from the LLISR 303. The injection well 308c and/or the production well 309c can be configured to inject pressure control fluids such as, for example, NCGs.

[00107] A dilbit storage method in an LLISR 303 having an equipment configuration similar to that shown in FIG. 8 has been simulated, and is broadly described below. The example discussed is a storage method that can reduce dilbit and/or diluent losses when storing dilbit in an LLISR 303.

[00108] FIG. 9 is a flow chart illustrating a general method for increasing the efficiency of storing dilbit in an LLISR 20, 102, 203, 303. At step 800, an initial quantity of dilbit can injected into an LLISR 20, 102, 203, 303. Preferably immediately after injection is complete, a portion of the initial quantity can be produced (step 802). Next, the method can proceed to step 804, wherein a quantity of dilbit that is less than the initial volume can be injected to increase or "top up" the quantity of dilbit stored in the LLISR 20, 102, 203, 303. After step 804, the method can return to step 802.

[00109] Turning to FIG. 10A, the LLISR 303 is depicted as it can appear at the end of a first injection phase (i.e., after step 800). Dilbit and/or diluent can be lost from the stored volume 320 in, e.g., the direction of the arrows extending from the stored volume 320. Illustrated in FIG. 10B is the LLISR 303 after a production phase (802). As shown, a portion of the stored volume 320 has been produced, leaving a smaller stored volume 320a. This portion can be produced through the production well 309b. After producing the portion, if storage is still required, a quantity of dilbit that can be less than the initial stored volume 320 can be injected again to be stored (step 840). In this way, the smaller stored volume 320a can be increased, or "topped up".

[00110] As noted above, it has been shown that initially creating a dilbit storage volume, and then repeatedly at least partially draining and at least partially refilling same can increase the efficiency of the dilbit storage, particularly with respect to diluent and/or dilbit loss. This can occur because during each injection cycle, the area surrounding the storage volume ("far field") can become more saturated with dilbit lost from the initial volume. The at least partially saturated far field area can serve as a barrier to help contain the dilbit (and diluent that can evaporate therefrom) injected in each cycle following the first, thereby reducing the loss of diluent and/or dilbit. It can be appreciated that one or more wells, such as "infill" wells (i.e., one or more additional wells positioned between existing wells), can be provided in the LLISR 20, 102, 203, 303 to collect dilbit migrating in undesired directions, such that the dilbit can be returned to the LLISR 20, 102, 203, 303 through the dilbit injector. For example, the infill wells could be positioned where far field saturation or other barriers are not sufficiently containing the dilbit.

[00111] For simplicity and clarity of illustration, where considered appropriate, reference numerals may be repeated among the figures to indicate corresponding or analogous elements. In addition, numerous specific details are set forth in order to provide a thorough understanding of the examples described herein. However, it will be understood by those of ordinary skill in the art that the examples described herein may be practiced without these specific details. In other instances, well-known methods, procedures and components have not been described in detail so as not to obscure the examples described herein. Also, the description is not to be considered as limiting the scope of the examples described herein.

[00112] The examples and corresponding diagrams used herein are for illustrative purposes only. Different configurations and terminology can be used without departing from the principles expressed herein. For instance, components and modules can be added, deleted, modified, or arranged with differing connections without departing from these principles.

[00113] The steps or operations in the flow charts and diagrams described herein are just for example. There may be many variations to these steps or operations without departing from the principles discussed above. For instance, the steps may be performed in a differing order, or some steps may be added, deleted, or modified.

[00114] Although the above principles have been described with reference to certain specific examples, various modifications thereof will be apparent to those skilled in the art as outlined in the appended claims.

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Claims:

1. A method of temporarily storing hydrocarbons in a thermal, late life, in situ reservoir (LLISR), the method comprising:

delivering hydrocarbons into the LLISR to establish a quantity of stored hydrocarbons in the LLISR; and

producing at least a portion of the stored hydrocarbons from the LLISR to recover a quantity of produced hydrocarbons.

2. The method of claim 1, wherein the hydrocarbons are delivered into the LLISR once the LLISR has cooled to a pre-determined temperature.

3. The method of claim 1 or claim 2, wherein the stored hydrocarbons are produced immediately after the hydrocarbons are delivered into the LLISR.

4. The method of any one of claims 1-3, wherein the quantity of produced hydrocarbons is less than the quantity of stored hydrocarbons delivered into the LLISR.

5. The method of claim 4, wherein delivering the hydrocarbons into the LLISR comprises increasing an existing quantity of stored hydrocarbons in the LLISR; and the method further comprising:

producing additional stored hydrocarbons from the LLISR.

6. The method of any one of claims 1-4, further comprising:

delivering additional hydrocarbons into the LLISR to increase the quantity of stored hydrocarbons remaining in the LLISR; and

producing at least a portion of the stored hydrocarbons to recover another quantity of produced hydrocarbons.

7. The method of claim 6, wherein the method is repeated at least once.

8. The method of any one of claims 1-7, further comprising removing contaminants from the produced hydrocarbons.

9. The method of claim 8, wherein the contaminants comprise one or more of chlorides, solids, and water.

10. The method of any one of claims 1-9, wherein the hydrocarbons are delivered into the LLISR by injection through a first well.

11. The method of claim 10, wherein at least some of the produced hydrocarbons are produced by the first well.

12. The method of claim 10 or claim 11, wherein at least some of the produced hydrocarbons are produced by a second well.

13. The method of claim 11, wherein a second well controls LLISR pressure by injecting an injection fluid into the LLISR.

14. The method of claim 12, wherein a third well provided in the LLISR controls LLISR pressure by injecting an injection fluid into the LLISR.

15. The method of claim 12, wherein the injection fluid creates a gas push from the second well in the direction of the first well.

16. The method of claim 14, wherein the injection fluid creates a gas push from the third well in the direction of the first and second wells.

17. The method of claim 13 or claim 15, wherein LLISR pressure is controlled at least in part by the second well to be approximately equal to a pressure in a nearby reservoir undergoing a thermal recovery process.

18. The method of claim 14 or claim 16, wherein LLISR pressure is controlled at least in part by the third well to be approximately equal to a pressure in a nearby reservoir undergoing a thermal recovery process.

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19. The method of claim 17, wherein the first well is positioned in a relatively warmer region of the LLISR, and the second well is positioned in a relatively colder region of the LLISR, the warmer region being closer in proximity to the reservoir than the colder region.

20. The method of claim 18, wherein the first well is positioned in a relatively warmer region of the LLISR, the third well is positioned in a relatively colder region of the LLISR, the warmer region being closer in proximity to the reservoir than the colder region, and the second well is positioned intermediate the first and third wells.

21. The method of any one of claims 10-20, further comprising producing through at least one other well, hydrocarbons positioned at the edge of or lost from the stored quantity, and returning the hydrocarbons to the LLISR through the first well.

22. The method of claim 21, wherein the at least one other well is an infill well.

23. The method of any one of claims 1-22, wherein the hydrocarbons comprise diluted bitumen, the diluted bitumen comprising bitumen and a diluent.

24. The method of claim 23, wherein the diluent comprises a C_2-C_{12} alkane, C_2-C_{12} alkene, C_3-C_{12} cycloalkane, C_3-C_{12} aromatic, or a combination thereof.

25. The method of claim 23 or claim 24, wherein the diluent comprises natural-gas condensates.

26. The method of any one of claims 23-25, wherein the diluent comprises naphtha.

27. The method of any one of claims 23-26, wherein LLISR pressure is controlled to limit vaporization of the diluent.

28. The method of any one of claims 13-27, wherein the injection fluid has a molecular weight similar to a molecular weight of the diluent.

29. The method of any one of claims 13-28, wherein the injection fluid comprises steam, naphtha, a C_2-C_{12} alkane, C_2-C_{12} alkene, C_3-C_{12} cycloalkane, C_3-C_{12} aromatic, or a combination thereof.

30. The method of any one of claims 13-28, wherein the injection fluid comprises a non-condensable gas (NCG).

31. The method of claim 30, wherein the NCG comprises at least one of N_2, CO_2, or methane.

32. The method of any one of claims 1-31, wherein the LLISR has been subjected to a steam assisted gravity drainage (SAGD) process prior to delivering the hydrocarbons into the LLISR.

33. The method of any one of claims 1-31, wherein the LLISR has been subjected to an expanding solvent SAGD (ES-SAGD) process prior to delivering the hydrocarbons into the LLISR.

34. The method of any one of claims 1-31, wherein the LLISR has been subjected to a thermal solvent recovery process prior to delivering the hydrocarbons into the LLISR.

35. A method of temporarily storing diluted bitumen in a thermal, late life, in situ reservoir (LLISR), the diluted bitumen comprising bitumen and a diluent, the method comprising:

delivering diluted bitumen into the LLISR to establish a quantity of stored diluted bitumen in the LLISR;

producing at least a portion of the stored diluted bitumen from the LLISR to recover a quantity of produced diluted bitumen; and

controlling pressure in the LLISR to limit vaporization of the diluent while delivering the diluted bitumen to, and/or while producing the stored diluted bitumen from, the LLISR.

36. The method of claim 35, wherein the diluted bitumen is delivered into the LLISR once the LLISR has cooled to a pre-determined temperature.

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37. The method of claim 35 or claim 36, wherein the stored diluted bitumen is produced immediately after the diluted bitumen is delivered into the LLISR.

38. The method of any one of claims 35-37, wherein the quantity of produced diluted bitumen is less than the quantity of stored diluted bitumen delivered into the LLISR.

39. The method of claim 38, wherein delivering the diluted bitumen into the LLISR comprises increasing an existing quantity of stored diluted bitumen in the LLISR; and the method further comprising:

producing additional stored diluted bitumen from the LLISR.

40. The method of any one of claims 35-39, further comprising:

delivering additional diluted bitumen into the LLISR to increase the quantity of stored diluted bitumen remaining in the LLISR; and

producing at least a portion of the stored diluted bitumen to recover another quantity of produced diluted bitumen.

41. The method of claim 40, wherein the method is repeated at least once.

42. The method of any one of claims 35-41, further comprising removing contaminants from the produced diluted bitumen.

43. The method of claim 42, wherein the contaminants comprise one or more of chlorides, solids, and water.

44. The method of any one of claims 35-43, wherein the diluted bitumen is delivered into the LLISR by injection through a first well.

45. The method of claim 44, wherein at least some of the produced diluted bitumen is produced by the first well.

46. The method of claim 44 or claim 45, wherein at least some of the produced diluted bitumen is produced by a second well.

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47. The method of claim 45, wherein a second well controls the LLISR pressure by injecting an injection fluid into the LLISR.

48. The method of claim 46, wherein a third well provided in the LLISR controls the LLISR pressure by injecting an injection fluid into the LLISR.

49. The method of claim 46, wherein the injection fluid creates a gas push from the second well in the direction of the first well.

50. The method of claim 48, wherein the injection fluid creates a gas push from the third well in the direction of the first and second wells.

51. The method of claim 47 or claim 49, wherein the LLISR pressure is controlled at least in part by the second well to be approximately equal to a pressure in a nearby reservoir undergoing a thermal recovery process.

52. The method of claim 48 or claim 50, wherein the LLISR pressure is controlled at least in part by the third well to be approximately equal to a pressure in a nearby reservoir undergoing a thermal recovery process.

53. The method of claim 51, wherein the first well is positioned in a relatively warmer region of the LLISR, and the second well is positioned in a relatively colder region of the LLISR, the warmer region being closer in proximity to the reservoir than the colder region.

54. The method of claim 52, wherein the first well is positioned in a relatively warmer region of the LLISR, the third well is positioned in a relatively colder region of the LLISR, the warmer region being closer in proximity to the reservoir than the colder region, and the second well is positioned intermediate the first and third wells.

55. The method of any one of claims 44-54, further comprising producing through at least one other well, diluted bitumen positioned at the edge of or lost from the stored quantity, and returning the diluted bitumen to the LLISR through the first well.

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56. The method of claim 55, wherein the at least one other well is an infill well.

57. The method of any one of claims 35 to 56, wherein the diluent comprises a C_2-C_{12} alkane, C_2-C_{12} alkene, C_3-C_{12} cycloalkane, C_3-C_{12} aromatic, or a combination thereof.

58. The method of claim 57, wherein the diluent comprises natural-gas condensates.

59. The method of claim 57 or claim 58, wherein the diluent comprises naphtha.

60. The method of any one of claims 47-59, wherein the injection fluid has a molecular weight similar to a molecular weight of the diluent.

61. The method of any one of claims 47-60, wherein the injection fluid comprises steam, naphtha, a C_2-C_{12} alkane, C_2-C_{12} alkene, C_3-C_{12} cycloalkane, C_3-C_{12} aromatic, or a combination thereof.

62. The method of any one of claims 47-60, wherein the injection fluid comprises a non-condensable gas (NCG).

63. The method of claim 62, wherein the NCG comprises at least one of N_2, CO_2, or methane.

64. The method of any one of claims 35-63, wherein the LLISR has been subjected to a steam assisted gravity drainage (SAGD) process prior to delivering the diluted bitumen into the LLISR.

65. The method of any one of claims 35-63, wherein the LLISR has been subjected to an expanding solvent SAGD (ES-SAGD) process prior to delivering the diluted bitumen into the LLISR.

66. The method of any one of claims 35-63, wherein the LLISR has been subjected to a thermal solvent recovery process prior to delivering the diluted bitumen into the LLISR.

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67. The method of any one of claims 35-66, wherein the LLISR has been subjected to a start-up process using diluent as a start-up fluid, prior to delivering the diluted bitumen into the LLISR.

68. The method of claim 67, wherein the diluent making up the diluted bitumen is substantially the same as the start-up fluid.

69. The method of any one of claims 35-66, wherein the LLISR has been subjected to a hydrocarbon production process using diluent as a production fluid, prior to delivering the diluted bitumen into the LLISR.

70. The method of claim 69, wherein the diluent making up the diluted bitumen is substantially the same as the production fluid.

71. A system for storing hydrocarbons in a thermal, late life, in situ reservoir (LLISR), the system comprising:

the LLISR;

a source of the hydrocarbons; and

a first well for injecting the hydrocarbons into the LLISR.

72. The system of claim 71, further comprising a reservoir undergoing a thermal recovery process, the reservoir being near the LLISR.

73. The system of claim 71 or claim 72, further comprising a second well for producing stored hydrocarbons from the LLISR and/or for pressure maintenance.

74. The system of claim 73, further comprising a third well for producing stored hydrocarbons from the LLISR and/or for pressure maintenance.

75. The system of claim 74, wherein the second well is configured to control LLISR pressure by injecting an injection fluid.

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76. The system of claim 74, wherein the third well is configured to control LLISR pressure by injecting an injection fluid.

77. The system of claim 75, wherein the first well is positioned in a relatively warmer region of the LLISR, and the second well is positioned in a relatively colder region of the LLISR, the warmer region being closer in proximity to the reservoir than the colder region.

78. The system of claim 76, wherein the first well is positioned in a relatively warmer region of the LLISR, the third well is positioned in a relatively colder region of the LLISR, the warmer region being closer in proximity to the reservoir than the colder region, and the second well is positioned intermediate the first and third wells.

79. The system of any one of claims 71-76, further comprising at least one infill well for producing hydrocarbons.

80. The system of any one of claims 71-77, wherein the hydrocarbons and the stored hydrocarbons comprise diluted bitumen, the diluted bitumen comprising bitumen and a diluent.

81. The system of claim 80, wherein the diluent comprises a C_2-C_{12} alkane, C_2-C_{12} alkene, C_3-C_{12} cycloalkane, C_3-C_{12} aromatic, or a combination thereof.

82. The system of claim 80 or claim 81, wherein the diluent comprises natural-gas condensates.

83. The system of any one of claims 80-82, wherein the diluent comprises naphtha.

84. The system of any one of claims 75-83, wherein the injection fluid has a molecular weight similar to a molecular weight of the diluent.

85. The system of any one of claims 75-84, wherein the injection fluid comprises steam, naphtha, a C_2-C_{12} alkane, C_2-C_{12} alkene, C_3-C_{12} cycloalkane, C_3-C_{12} aromatic, or a combination thereof.

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86. The system of any one of claims 75-85, wherein the injection fluid comprises a non-condensable gas (NCG).

87. The system of claim 86, wherein the NCG comprises at least one of N_2, CO_2, or methane.

88. The system of any one of claims 71-87, wherein the source of hydrocarbons is an in situ hydrocarbon recovery facility.

89. The system of claim 71, further comprising injection equipment configured to deliver the hydrocarbons into the LLISR once the LLISR has cooled to a pre-determined temperature.

90. The system of claim 73, wherein the second well is configured to produce the stored hydrocarbons immediately after the hydrocarbons are delivered into the LLISR.

91. The system of claim 73, wherein the quantity of produced hydrocarbons produced from the second well is less than the quantity of stored hydrocarbons delivered into the LLISR.

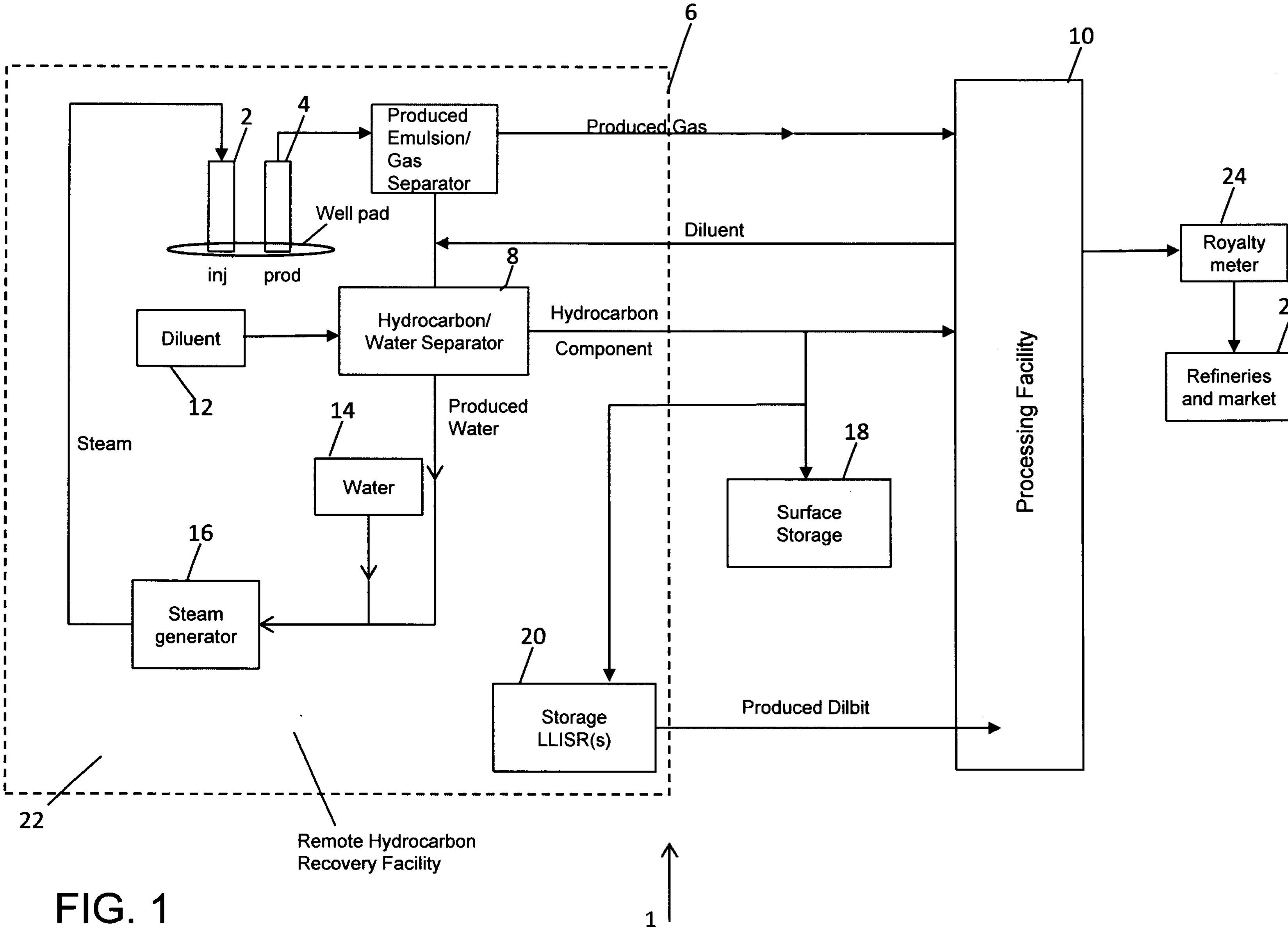
92. The system of any one of claims 71-91, further comprising equipment to remove contaminants from the produced hydrocarbons.

93. The system of claim 92, wherein the contaminants comprise one or more of chlorides, solids, and water.

94. The system of any one of claims 71-93, wherein the LLISR has been subjected to a steam assisted gravity drainage (SAGD) process, prior to delivering the diluted bitumen into the LLISR.

95. The system of any one of claims 71-93, wherein the LLISR has been subjected to an expanding solvent SAGD (ES-SAGD), prior to delivering the diluted bitumen into the LLISR.

96. The system of any one of claims 71-93, wherein the LLISR has been subjected to a thermal solvent recovery process, prior to delivering the diluted bitumen into the LLISR.



6
10
2
4
Produced Emulsion/ Gas Separator
Produced Gas
Well pad
inj
prod
Diluent
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Royalty meter
8
26
Hydrocarbon/ Water Separator
Hydrocarbon
Component
Diluent
12
Refineries and market
14
Produced Water
Steam
Processing Facility
18
Water
Surface Storage
16
Steam generator
20
Storage LLISR(s)
Produced Dilbit
22
Remote Hydrocarbon Recovery Facility
1

FIG. 1

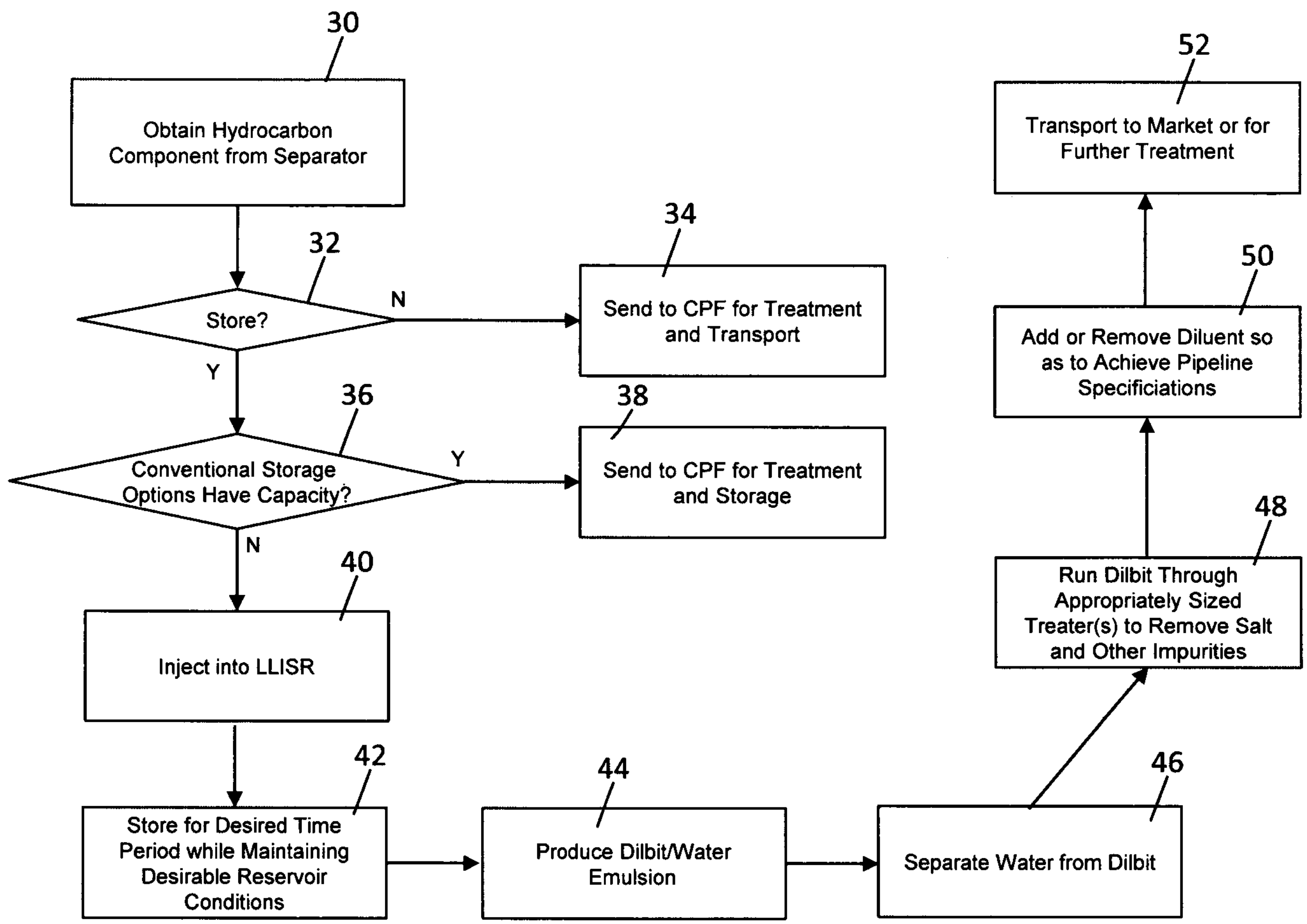
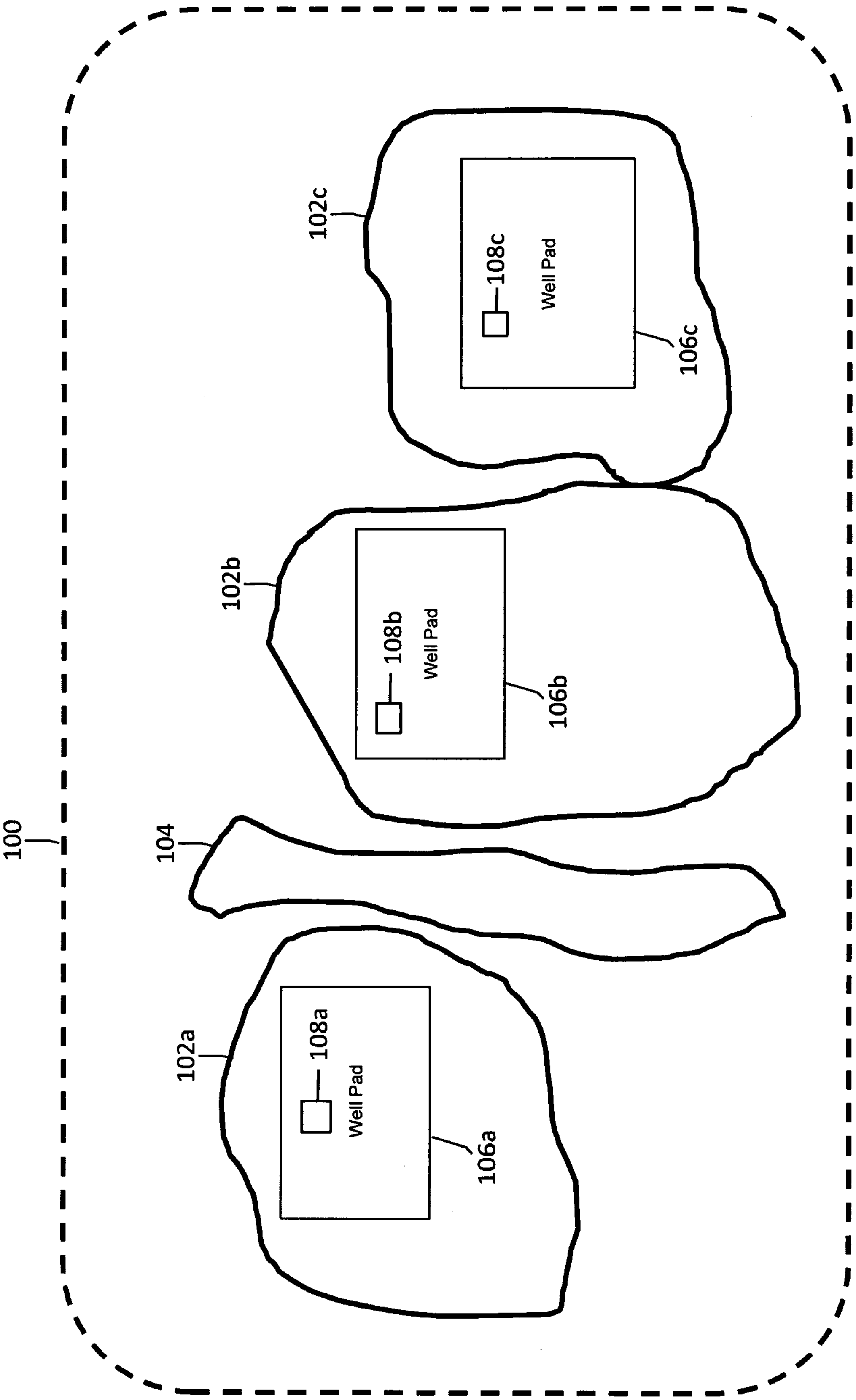

30
Obtain Hydrocarbon Component from Separator
32
Store?
N
Y
34
Send to CPF for Treatment and Transport
36
Conventional Storage Options Have Capacity?
Y
N
38
Send to CPF for Treatment and Storage
40
Inject into LLISR
42
Store for Desired Time Period while Maintaining Desirable Reservoir Conditions
44
Produce Dilbit/Water Emulsion
46
Separate Water from Dilbit
48
Run Dilbit Through Appropriately Sized Treater(s) to Remove Salt and Other Impurities
50
Add or Remove Diluent so as to Achieve Pipeline Specifications
52
Transport to Market or for Further Treatment

FIG. 2



100
104
102a
108a
Well Pad
106a
102b
108b
Well Pad
106b
102c
108c
Well Pad
106c

FIG. 3

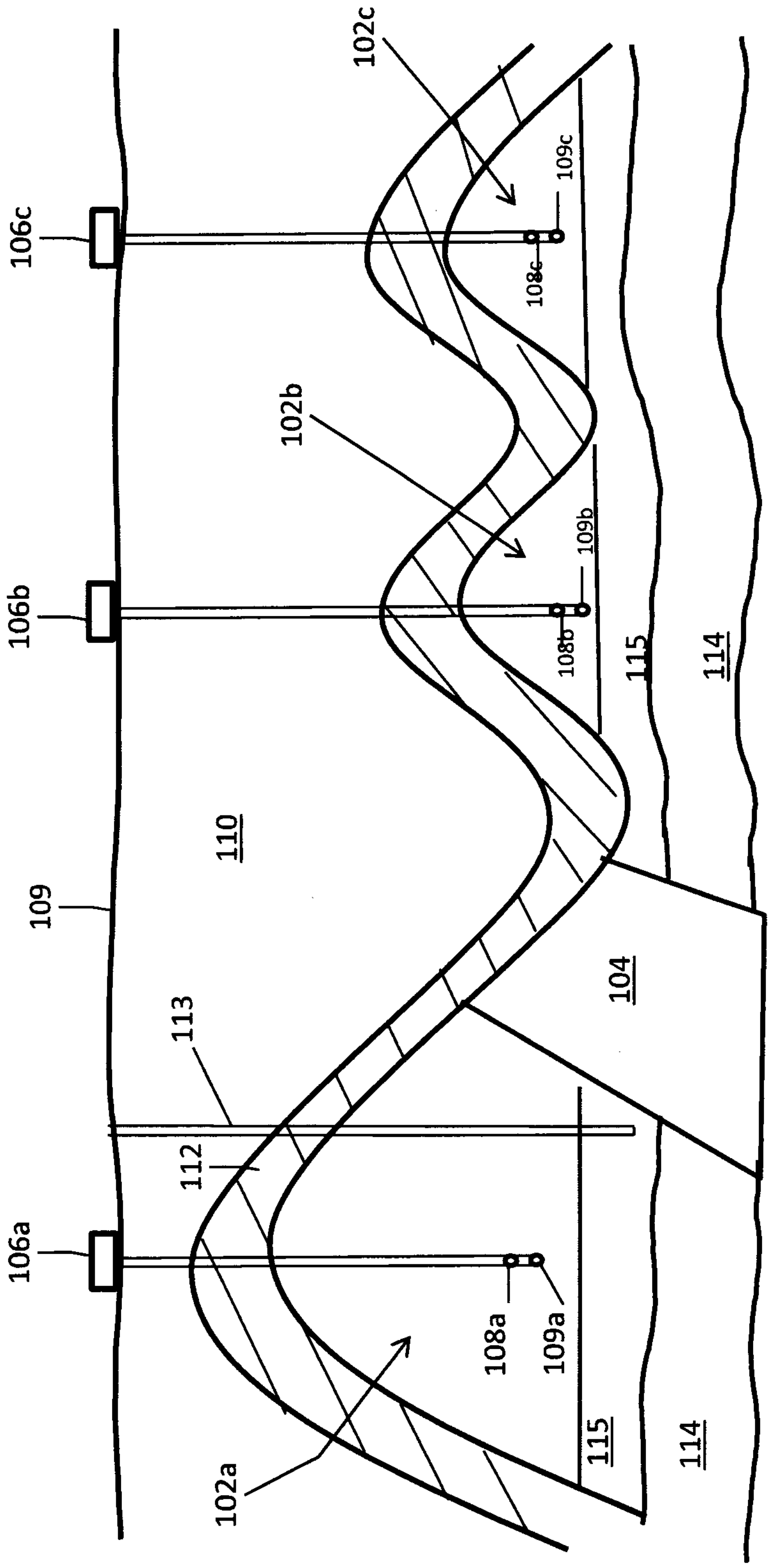

106a
106b
106c
109
110
113
112
102a
102b
102c
104
108a
109a
108b
109b
108c
109c
115
115
114
114

FIG. 4

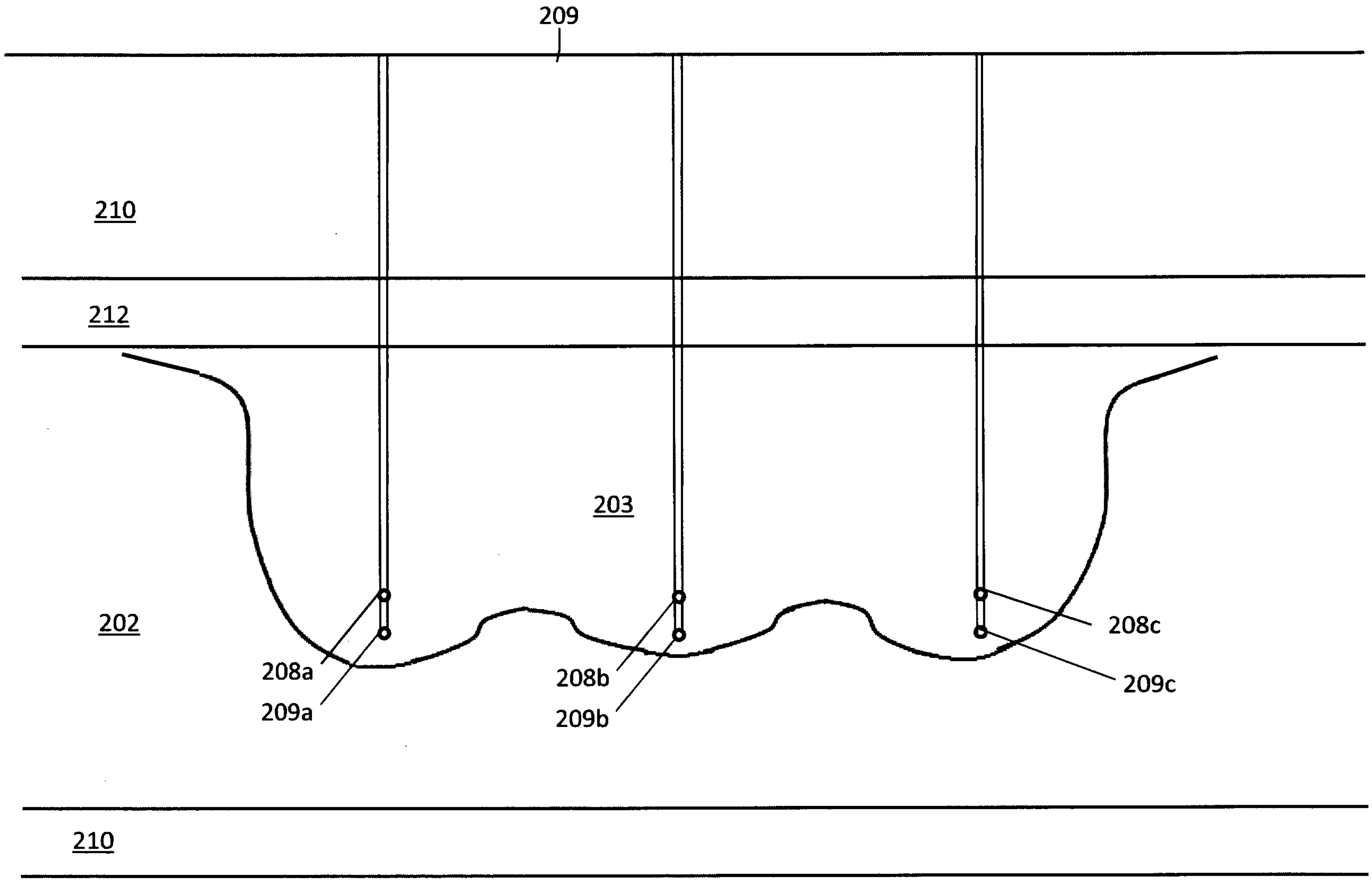


FIG. 5

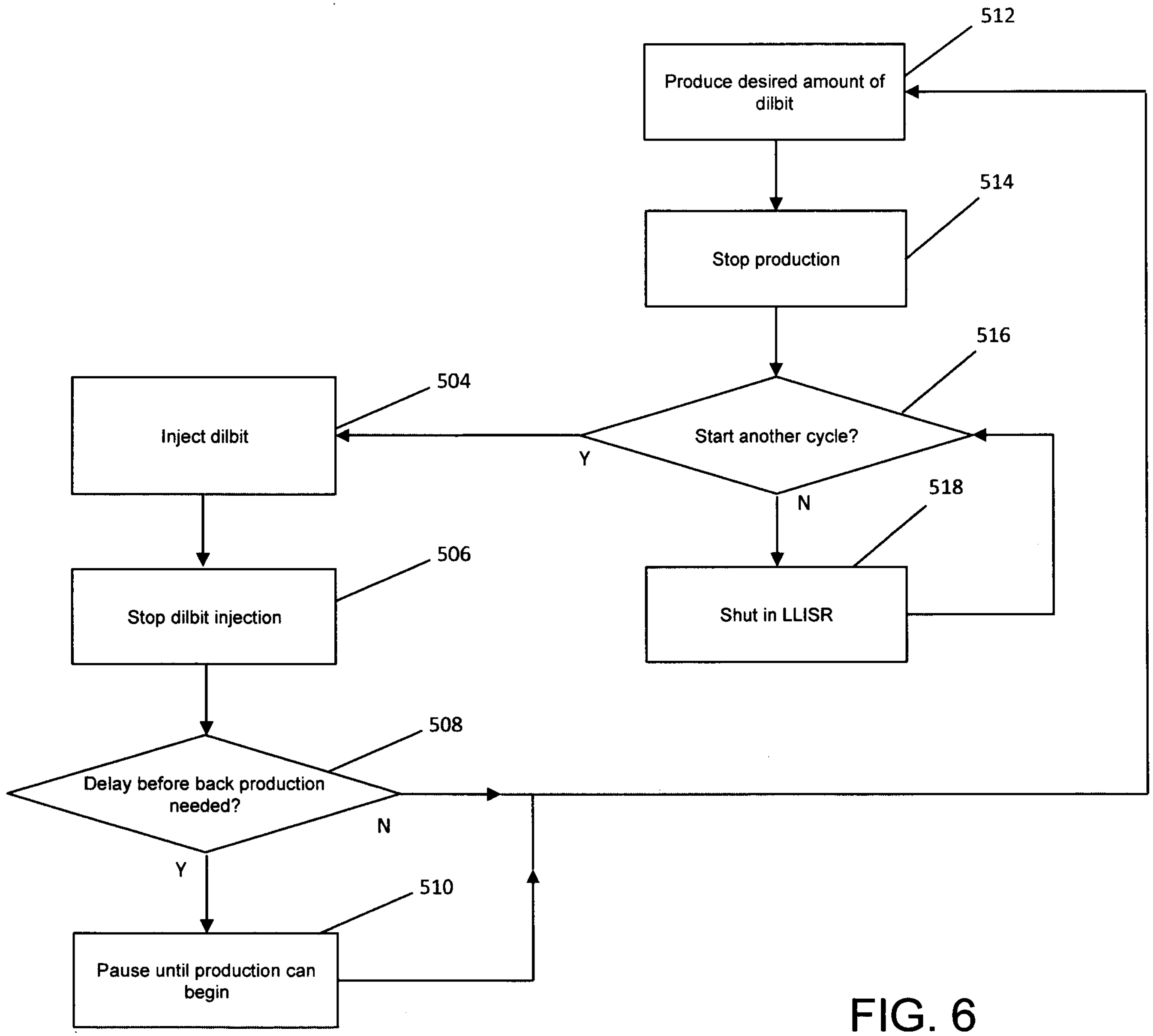

512
Produce desired amount of dilbit
514
Stop production
516
Start another cycle?
Y
N
518
Shut in LLISR
504
Inject dilbit
506
Stop dilbit injection
508
Delay before back production needed?
N
Y
510
Pause until production can begin

FIG. 6

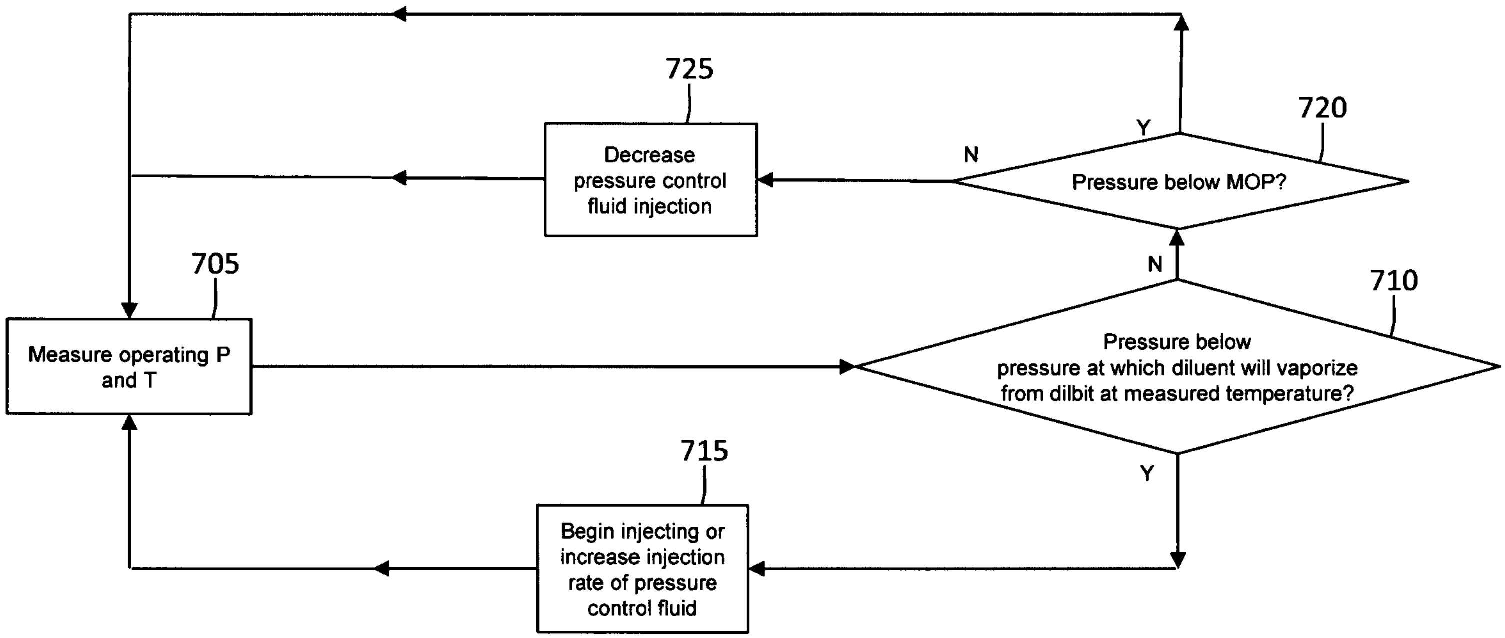

725
720
Decrease
pressure control
fluid injection
Y
N
Pressure below MOP?
705
N
710
Measure operating P
and T
Pressure below
pressure at which diluent will vaporize
from dilbit at measured temperature?
715
Y
Begin injecting or
increase injection
rate of pressure
control fluid

FIG. 7

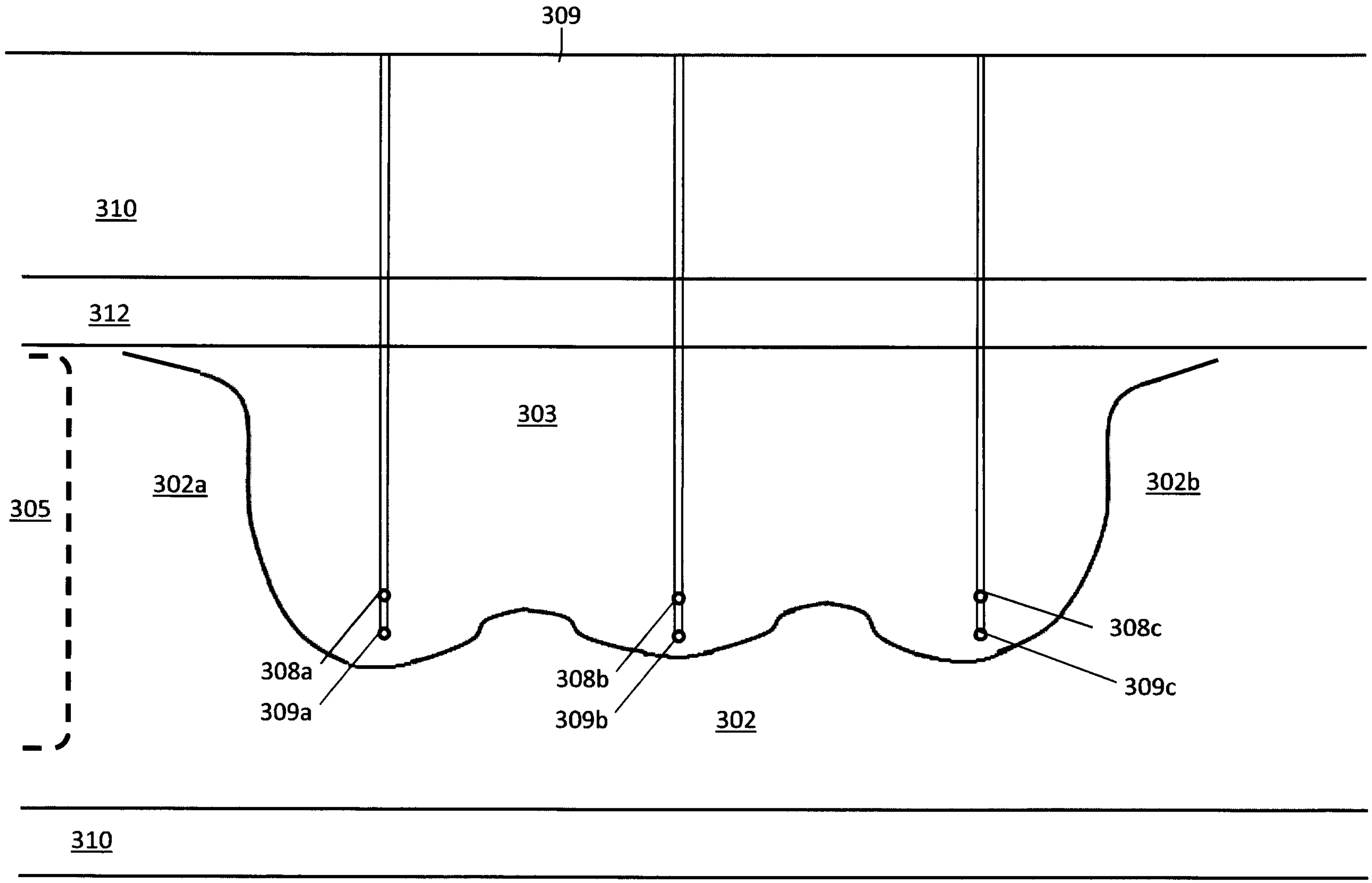

309
310
312
303
305
302a
302b
308a
309a
308b
309b
302
308c
309c
310

FIG. 8

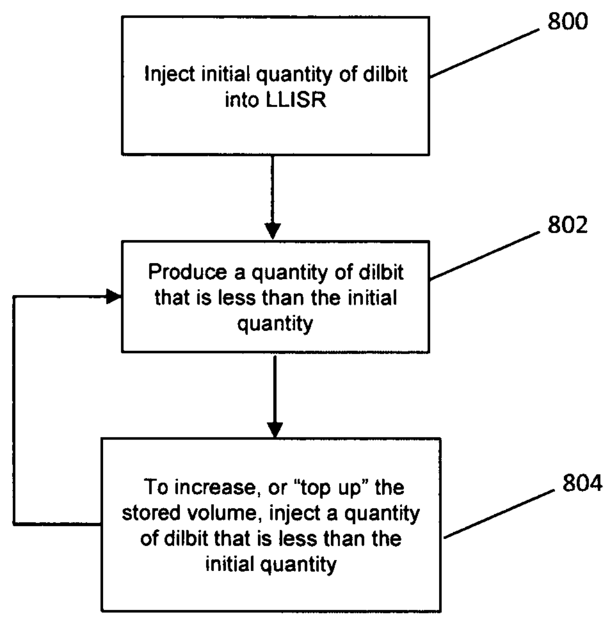

Inject initial quantity of dilbit into LLISR
800
Produce a quantity of dilbit that is less than the initial quantity
802
To increase, or "top up" the stored volume, inject a quantity of dilbit that is less than the initial quantity
804

FIG. 9

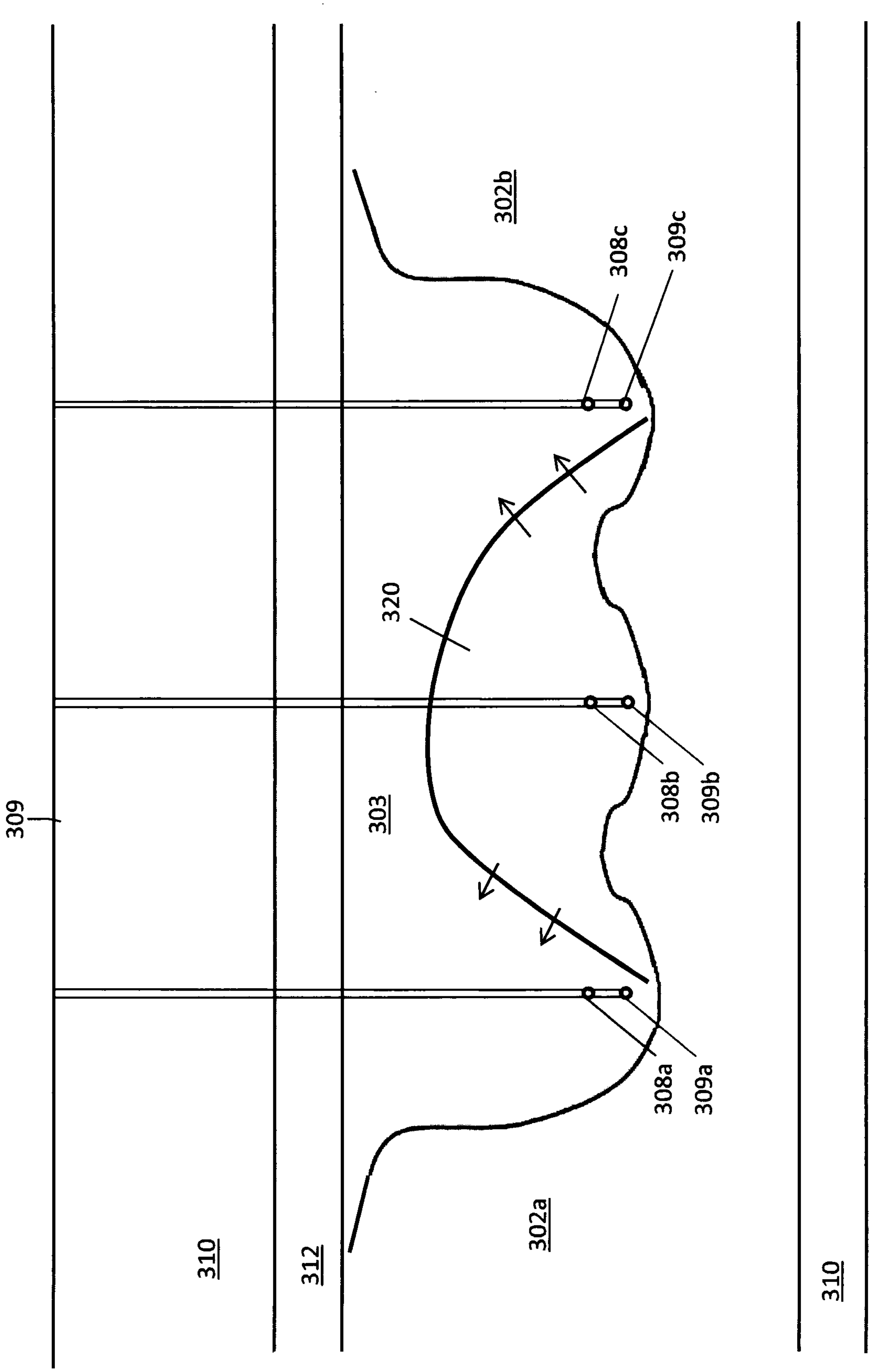

309
310
312
303
302a
302b
320
308a
309a
308b
309b
308c
309c
310

FIG. 10A

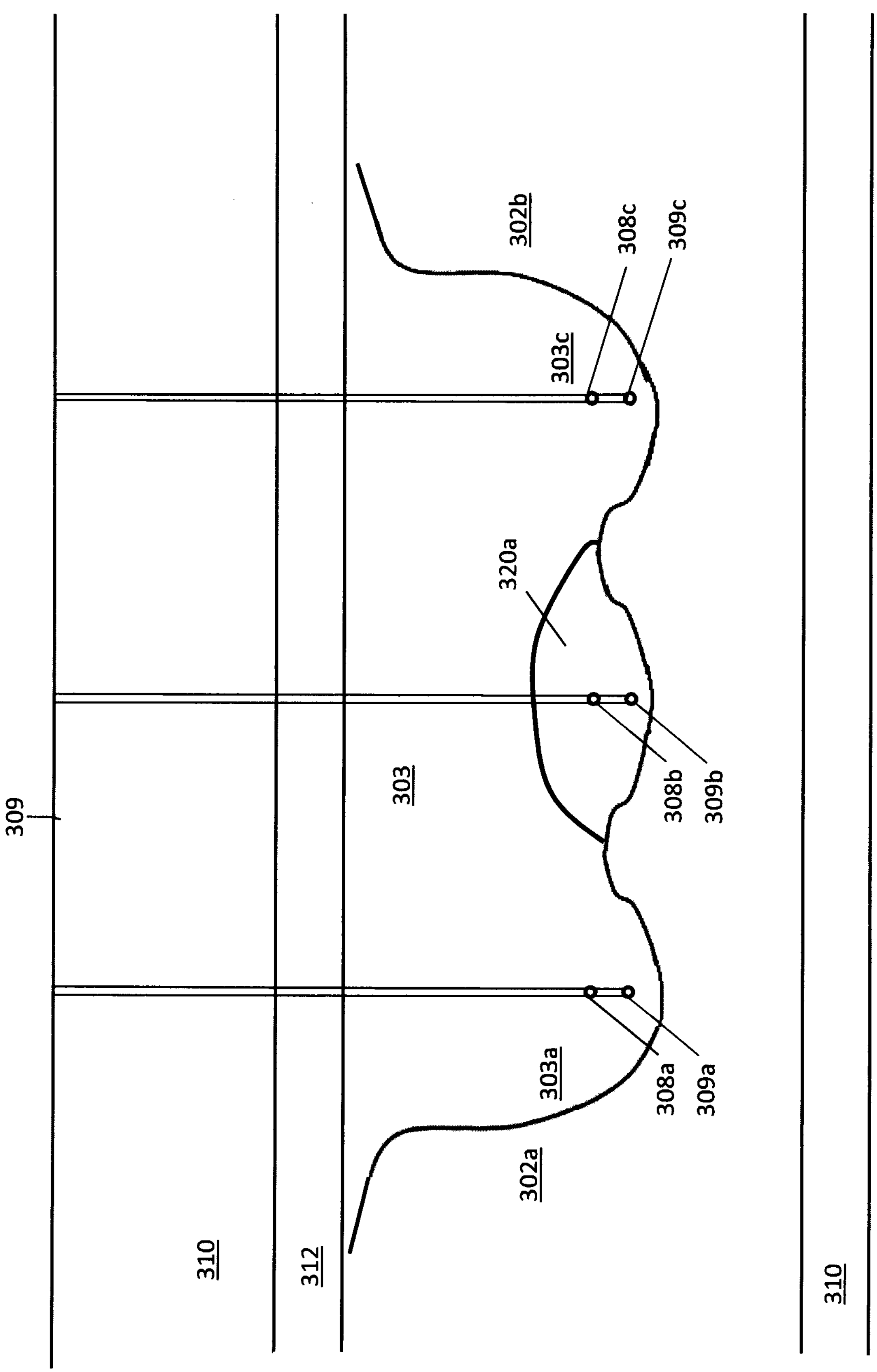
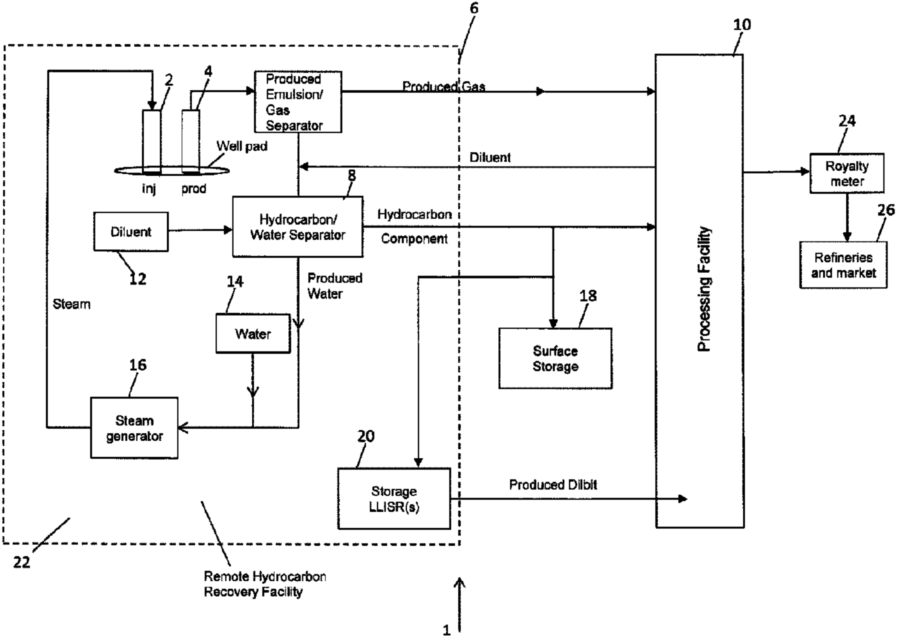

309
310
312
303
302a
303a
302b
303c
320a
308a
309a
308b
309b
308c
309c
310

FIG. 10B



6
10
2
4
Produced Emulsion/ Gas Separator
Produced Gas
Well pad
Diluent
24
Royalty meter
inj
prod
8
Diluent
Hydrocarbon/ Water Separator
Hydrocarbon
Component
26
Refineries and market
12
14
Produced Water
Steam
18
Water
Surface Storage
Processing Facility
16
Steam generator
20
Storage LLISR(s)
Produced Dilbit
22
Remote Hydrocarbon Recovery Facility
1