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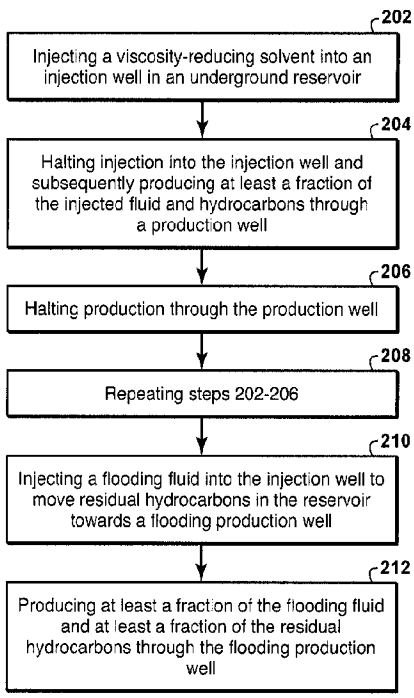


(57) Abrégé/Abstract:
A process for recovering hydrocarbons from an underground reservoir may include injecting an injected fluid into the underground reservoir; halting injection and subsequently producing at least a fraction of the injected fluid and the hydrocarbons from the underground reservoir; halting production; repeating the aforementioned steps; injecting a flooding fluid to move residual hydrocarbons towards a flooding production well for further production; and producing at least a fraction of the flooding fluid and the residual hydrocarbons.

ABSTRACT

A process for recovering hydrocarbons from an underground reservoir may include injecting an injected fluid into the underground reservoir; halting injection and subsequently producing at least a fraction of the injected fluid and the hydrocarbons from the underground reservoir; halting production; repeating the aforementioned steps; injecting a flooding fluid to move residual hydrocarbons towards a flooding production well for further production; and producing at least a fraction of the flooding fluid and the residual hydrocarbons.

RECOVERING HYDROCARBONS FROM AN UNDERGROUND RESERVOIR

BACKGROUND

Field of Disclosure

[0001] The disclosure relates generally to the recovery of hydrocarbons. More specifically, the disclosure relates to recovery hydrocarbons from an underground reservoir.

Description of Related Art

[0002] This section is intended to introduce various aspects of the art, which may be associated with the present disclosure. This discussion is believed to assist in providing a framework to facilitate a better understanding of particular aspects of the present disclosure. Accordingly, it should be understood that this section should be read in this light, and not necessarily as admissions of prior art.

[0003] Modern society is greatly dependent on the use of hydrocarbon resources for fuels and chemical feedstocks. Hydrocarbons are generally found in subsurface formations that can be termed "reservoirs." Removing hydrocarbons from the reservoirs depends on numerous physical properties of the subsurface formations, such as the permeability of the rock containing the hydrocarbons, the ability of the hydrocarbons to flow through the subsurface formations, and the proportion of hydrocarbons present, among other things. Easily harvested sources of hydrocarbons are dwindling, leaving less accessible sources to satisfy future energy needs. As the prices of hydrocarbons increase, the less accessible sources become more economically attractive.

[0004] Recently, the harvesting of oil sands to remove heavy oil has become more economical. Hydrocarbon removal from oil sands may be performed by several techniques. For example, a well can be drilled to an oil sand reservoir and steam, hot gas, solvents, or a combination thereof, can be injected to release the hydrocarbons. The released hydrocarbons may be collected by wells and brought to the surface.

[0005] At the present time, solvent-dominated recovery processes (SDRPs) are not commonly used as commercial recovery processes to produce highly viscous oil.

Solvent-dominated means that the injectant comprises greater than 50 percent (%) by mass of solvent or that greater than 50% of the produced oil's viscosity reduction is obtained by chemical solvation rather than by thermal means. Highly viscous oils are produced primarily using thermal methods in which heat, typically in the form of steam, is added to the reservoir. Cyclic solvent-dominated recovery processes (CSDRPs) are a subset of SDRPs. A CSDRP may be a non-thermal recovery method that uses a solvent to mobilize viscous oil by cycles of injection and production. One possible laboratory method for roughly comparing the relative contribution of heat and dilution to the viscosity reduction obtained in a proposed oil recovery process is to compare the viscosity obtained by diluting an oil sample with a solvent to the viscosity reduction obtained by heating the sample.

[0006] In a CSDRP, a viscosity-reducing solvent may be injected through a well into a subterranean formation, causing pressure to increase. Next, the pressure is lowered and reduced-viscosity oil is produced to the surface of the subterranean formation through the same well through which the solvent was injected. Multiple cycles of injection and production may be used.

[0007] CSDRPs may be particularly attractive for thinner or lower-oil-saturation reservoirs. In such reservoirs, thermal methods utilizing heat to reduce viscous oil viscosity may be inefficient due to excessive heat loss to the overburden and/or underburden and/or reservoir with low oil content.

[0008] References describing specific CSDRPs include: Canadian Patent No. 2,349,234 (Lim *et al.*); G. B. Lim *et al.*, "Three-dimensional Scaled Physical Modeling of Solvent Vapour Extraction of Cold Lake Bitumen", *The Journal of Canadian Petroleum Technology,* 35(4), pp. 32-40, April 1996; G. B. Lim *et al.*, "Cyclic Stimulation of Cold Lake Oil Sand with Supercritical Ethane", *SPE Paper 30298*, 1995; U.S. Patent No. 3,954,141 (Allen *et al.*); and M. Feali *et al.*, "Feasibility Study of the Cyclic VAPEX Process for Low Permeable Carbonate Systems", *International Petroleum Technology Conference Paper 12833*, 2008.

[0009] The family of processes within the *Lim et al.* references describes a particular SDRP that is also a cyclic solvent-dominated recovery process (CSDRP). These processes relate to the recovery of heavy oil and bitumen from subterranean reservoirs using cyclic injection of a solvent in the liquid state which vaporizes upon production.

[0010] With reference to Figure 1, which is a simplified diagram based on Canadian Patent No. 2,349,234 (Lim *et al.*), one CSDRP process is described as a single well method for cyclic solvent stimulation, the single well preferably having a horizontal wellbore portion and a perforated liner section. A vertical wellbore (1) driven through overburden (2) into reservoir (3) is connected to a horizontal wellbore portion (4). The horizontal wellbore portion (4) comprises a perforated liner section (5) and an inner bore (6). The horizontal wellbore portion comprises a downhole pump (7). In operation, solvent or viscosified solvent is driven down and diverted through the perforated liner section (5) where it percolates into reservoir (3) and penetrates reservoir material to yield a reservoir penetration zone (8). Oil dissolved in the solvent or viscosified solvent flows into the well and is pumped by downhole pump through an inner bore (6) through a motor at the wellhead (9) to a production tank (10) where oil and solvent are separated and the solvent is recycled.

[0011] Solvent dominated recovery processes (SDRPs) may leave valuable residual hydrocarbons in the ground. Thus, there is a need for a process that is able to to recover residual hydrocarbons.

SUMMARY

[0012] It is an object of the present disclosure to provide a process that is able to recover residual hydrocarbons.

[0013] A process for recovering hydrocarbons from an underground reservoir may comprise (a) injecting injected fluid, comprising greater than 50 mass % of a viscosity-reducing solvent, into an injection well completed in the underground reservoir; (b) halting injection into the injection well and subsequently producing at least a fraction of the injected fluid and the hydrocarbons from the underground reservoir through a production well; (c) halting production through the production well; (d) repeating steps (a) to (c); (e) injecting a flooding fluid into the injection well to move residual hydrocarbons in the underground reservoir towards a flooding production well horizontally spaced from the injection well and the production well; and (f) producing at least a fraction of the flooding fluid and at least a fraction of the residual hydrocarbons through the flooding production well.

[0014] The foregoing has broadly outlined the features of the present disclosure so that the detailed description that follows may be better understood. Additional features will also be described herein.

BRIEF DESCRIPTION OF THE DRAWINGS

[0015] These and other features, aspects and advantages of the disclosure will become apparent from the following description, appending claims and the accompanying drawings, which are briefly described below.

[0016] Fig. 1 is a schematic of a cyclic solvent-dominated recovery process.

[0017] Fig. 2 is a flow chart of process for recovering hydrocarbons.

[0018] It should be noted that the figures are merely examples and no limitations on the scope of the present disclosure are intended thereby. Further, the figures are generally not drawn to scale, but are drafted for purposes of convenience and clarity in illustrating various aspects of the disclosure.

DETAILED DESCRIPTION

[0019] For the purpose of promoting an understanding of the principles of the disclosure, reference will now be made to the featůres illustrated in the drawings and specific language will be used to describe the same. It will nevertheless be understood that no limitation of the scope of the disclosure is thereby intended. Any alterations and further modifications, and any further applications of the principles of the disclosure as described herein are contemplated as would normally occur to one skilled in the art to which the disclosure relates. It will be apparent to those skilled in the relevant art that some features that are not relevant to the present disclosure may not be shown in the drawings for the sake of clarity.

[0020] At the outset, for ease of reference, certain terms used in this application and their meaning, as used in this context, are set forth below. To the extent a term used herein is not defined below, it should be given the broadest definition persons in the pertinent art have given that term as reflected in at least one printed publication or issued patent. Further, the present processes are not limited by the usage of the terms shown below, as all equivalents, synonyms, new developments and terms or processes that serve the same or a similar purpose are considered to be within the scope of the present disclosure.

[0021] A "hydrocarbon" is an organic compound that primarily includes the elements of hydrogen and carbon, although nitrogen, sulfur, oxygen, metals, or any number of other elements may be present in small amounts. Hydrocarbons generally refer to components found in heavy oil or in oil sands. Hydrocarbon compounds may be aliphatic or aromatic, and may be straight chained, branched, or partially or fully cyclic.

[0022] "Bitumen" is a naturally occurring heavy oil material. Generally, it is the hydrocarbon component found in oil sands. Bitumen can vary in composition depending upon the degree of loss of more volatile components. It can vary from a very viscous, tar-like, semi-solid material to solid forms. The hydrocarbon types found in bitumen can include aliphatics, aromatics, resins, and asphaltenes. A typical bitumen might be composed of:

19 weight (wt.) percent (%) aliphatics (which can range from 5 wt. % - 30 wt. %, or higher);

19 wt. % asphaltenes (which can range from 5 wt. % - 30 wt. %, or higher);

30 wt. % aromatics (which can range from 15 wt. % - 50 wt. %, or higher);

32 wt. % resins (which can range from 15 wt. % - 50 wt. %, or higher); and

some amount of sulfur (which can range in excess of 7 wt. %).

In addition, bitumen can contain some water and nitrogen compounds ranging from less than 0.4 wt. % to in excess of 0.7 wt. %. The percentage of the hydrocarbon found in bitumen can vary. The term "heavy oil" includes bitumen as well as lighter materials that may be found in a sand or carbonate reservoir.

[0023] "Heavy oil" includes oils which are classified by the American Petroleum Institute ("API"), as heavy oils, extra heavy oils, or bitumens. The term "heavy oil" includes bitumen. Heavy oil may have a viscosity of about 1,000 centipoise (cP) or more, 10,000 cP or more, 100,000 cP or more, or 1,000,000 cP or more. In general, a heavy oil has an API gravity between 22.3° API (density of 920 kilograms per meter cubed (kg/m3) or 0.920 grams per centimeter cubed (g/cm3)) and 10.0° API (density of 1,000 kg/m3 or 1 g/cm3). An extra heavy oil, in general, has an API gravity of less than 10.0° API (density greater than 1,000 kg/m3 or 1 g/cm3). For example, a source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, sand, water and bitumen.

[0024] The term "viscous oil" as used herein means a hydrocarbon, or mixture of hydrocarbons, that occurs naturally and that has a viscosity of at least 10 cP (centipoise) at initial reservoir conditions. Viscous oil includes oils generally defined as "heavy oil" or "bitumen". Bitumen is classified as an extra heavy oil, with an API gravity of about 10° or less, referring to its gravity as measured in degrees on the American Petroleum Institute

(API) Scale. Heavy oil has an API gravity in the range of about 22.3° to about 10°. The terms viscous oil, heavy oil, and bitumen are used interchangeably herein since they may be extracted using similar processes.

[0025] In-situ is a Latin phrase for "in the place" and, in the context of hydrocarbon recovery, refers generally to a subsurface hydrocarbon-bearing reservoir. For example, in-situ temperature means the temperature within the reservoir. In another usage, an in-situ oil recovery technique is one that recovers oil from a reservoir within the earth.

[0026] The term "subterranean formation" refers to the material existing below the Earth's surface. The subterranean formation may comprise a range of components, e.g. minerals such as quartz, siliceous materials such as sand and clays, as well as the oil and/or gas that is extracted. The subterranean formation may be a subterranean body of rock that is distinct and continuous. The terms "reservoir" and "formation" may be used interchangeably.

[0027] The terms "approximately," "about," "substantially," and similar terms are intended to have a broad meaning in harmony with the common and accepted usage by those of ordinary skill in the art to which the subject matter of this disclosure pertains. It should be understood by those of skill in the art who review this disclosure that these terms are intended to allow a description of certain features described and claimed without restricting the scope of these features to the precise numeral ranges provided. Accordingly, these terms should be interpreted as indicating that insubstantial or inconsequential modifications or alterations of the subject matter described and are considered to be within the scope of the disclosure.

[0028] The articles "the", "a" and "an" are not necessarily limited to mean only one, but rather are inclusive and open ended so as to include, optionally, multiple such elements.

[0029] "At least one," in reference to a list of one or more entities should be understood to mean at least one entity selected from any one or more of the entity in the list of entities, but not necessarily including at least one of each and every entity specifically listed within the list of entities and not excluding any combinations of entities in the list of entities. This definition also allows that entities may optionally be present other than the entities specifically identified within the list of entities to which the phrase "at least one" refers, whether related or unrelated to those entities specifically identified. Thus, as a non-limiting example, "at least one of A and B" (or, equivalently, "at least one of A or B," or, equivalently "at least one of A and/or B") may refer, to at least one, optionally including more than one, A, with no B present (and optionally including entities other than B); to at least one, optionally including more than one, B, with no A present (and optionally including entities other than A); to at least one, optionally including more than one, A, and at least one, optionally including more than one, B (and optionally including other entities). In other words, the phrases "at least one," "one or more," and "and/or" are open-ended expressions that are both conjunctive and disjunctive in operation. For example, each of the expressions "at least one of A, B and C," "at least one of A, B, or C," "one or more of A, B, and C," "one or more of A, B, or C" and "A, B, and/or C" may mean A alone, B alone, C alone, A and B together, A and C together, B and C together, A, B and C together, and optionally any of the above in combination with at least one other entity.

[0030] Where two or more ranges are used, such as but not limited to 1 to 5 or 2 to 4, any number between or inclusive of these ranges is implied.

[0031] As used herein, the phrase, "for example," the phrase, "as an example," and/or simply the term "example," when used with reference to one or more components, features, details, structures, and/or methods according to the present disclosure, are intended to convey that the described component, feature, detail, structure, and/or method is an illustrative, non-exclusive example of components, features, details, structures, and/or methods according to the present disclosure. Thus, the described component, feature, detail, structure, and/or method is not intended to be limiting, required, or exclusive/exhaustive; and other components, features, details, structures, and/or methods, including structurally and/or functionally similar and/or equivalent components, features, details, structures, and/or methods, are also within the scope of the present disclosure.

[0032] During a CSDRP, a reservoir may accommodate injected viscosity-reducing solvent and non-solvent fluid (also referred to as "additional injectants" or "non-solvent injectants") by compressing the pore fluids. During a CSDRP, a reservoir may accommodate injected viscosity-reducing solvent and non-solvent fluid (also referred to as "additional injectants" or "non-solvent injectants") by dilating a reservoir pore space by applying an injection pressure. Dilating the reservoir pore space may be any effective mechanism for permitting viscosity-reducing solvent to enter into reservoirs filled with viscous oils when the reservoir comprises unconsolidated sand grains. The viscous oils may interchangeably be referred to as hydrocarbons. Injected viscosity-reducing solvent fingers into the oil sands and mixes with the viscous oil to yield a reduced viscosity mixture with higher mobility than the native viscous oil. "Fingering" may occur when two fluids of different viscosities come in contact with one another and one fluid penetrates the other in a finger-like pattern, that is, in an uneven manner. The primary mixing mechanism may be dispersive mixing, not diffusion. Injected fluid in each cycle may replace the volume of previously recovered fluid. Injected fluid in each cycle may add additional fluid to contact previously uncontacted viscous oil. The injected fluid may comprise greater than 50% by mass of viscosity-reducing solvent. The injection well and the production well may utilize a common wellbore.

[0033] While producing hydrocarbon during the CSDRP process, pressure may be reduced and the viscosity-reducing solvent(s), non-solvent injectant, and viscous oil may flow back to the same well in which the solvent(s) and non-solvent injectant were injected and are produced to the surface of the reservoir as produced fluid. The produced fluid may be a mixture of the viscosity-reducing solvent and viscous oil. As the pressure in the reservoir falls, the produced fluid rate may decline with time. Production of the produced fluid may be governed by any of the following mechanisms: gas drive via viscosity-reducing solvent vaporization and native gas exsolution, compaction drive as the reservoir dilation relaxes, fluid expansion, and gravity-driven flow. The relative importance of the mechanisms depends on static properties such as viscosity-reducing solvent properties, native GOR (Gas to Oil Ratio), fluid and rock compressibility characteristics, and/or reservoir depth. The relative importance of the mechanism may depend on operational practices such as viscosity-reducing solvent injection volume, producing pressure, and/or viscous oil recovery to-date, among other factors.

[0034] During an injection/production cycle (i.e. a cycle comprising injecting an injected fluid followed by producing hydrocarbons), the volume of produced oil within the produced fluid may be above a minimum threshold to economically justify continuing the CSDRP process. The produced oil within the produced fluid may be recovered. One measure of the efficiency of a CSDRP is the ratio of produced oil volume to injected solvent volume over a time interval, called the OISR (produced Oil to Injected Solvent Ratio). The time interval may be one complete injection/production cycle. The time interval may be from the beginning of first injection to the present or some other time interval. When the ratio falls below a certain threshold, further viscosity-reducing solvent injection may become uneconomic, indicating the viscosity-reducing solvent should be injected into a different well operating at a higher OISR. The exact OISR threshold depends on the relative price of viscous oil and viscosity-reducing solvent, among other factors. If either the oil production rate or the OISR becomes too low, the CSDRP may be discontinued. Viscosity-reducing solvent may interchangeably be referred to as solvent. Even if oil rates are high and the solvent use is efficient, where efficiency may be measured for instance by the OISR, for instance an OISR of above 0.15, it is important to recover as much of the injected solvent as possible if it has economic value. Depending on the physical properties of the injected solvent, the remaining solvent may be recovered by producing to a low pressure to vaporize the solvent in the reservoir to aid its recovery. One measure of solvent recovery is the percentage of solvent recovered divided by the total injected. Rather than abandoning the well after the CSDRP, another recovery process may be initiated. To maximize the economic return of a producing oil well, it is desirable to maintain an economic oil production rate and OISR as long as possible and then recover as much of the solvent as possible.

[0035] The OISR may be one measure of solvent efficiency. Those skilled in the art will recognize that there are a multitude of other measures of solvent efficiency, such as the inverse of the OISR, or measures of solvent efficiency on a temporal basis that is different from the temporal basis discussed in this disclosure. Solvent recovery percentage is just one measure of solvent recovery. Those skilled in the art will recognize that there are many other measures of solvent recovery, such as the percentage loss, volume of unrecovered solvent per volume of recovered oil, or its inverse, the volume of produced oil to volume of lost solvent ratio (OLSR).

[0036] Solvent Storage Ratio (SSR) may be a common measure of solvent efficiency. The SSR is a measure of the solvent fraction unrecovered from the reservoir divided by the in-situ oil produced from the reservoir. SSR is more explicitly defined as the ratio of the cumulative solvent injected into the reservoir minus the cumulative solvent produced from the reservoir to the cumulative in-situ oil produced from the reservoir. A lower SSR indicates lower solvent losses per volume of in-situ oil recovered, and thus, better total solvent recovery per volume of in-situ oil produced. A lower SSR would indicate an improvement in solvent efficiency.

[0037] As used herein, "improving solvent efficiency" means (a) improving the OISR, or (b) improving the SSR, or (c) improving both the OISR and the SSR.

[0038] Solvent composition

[0039] The solvent may be a light, but condensable, hydrocarbon or mixture of hydrocarbons comprising ethane, propane, butane, or pentane. The solvent may comprise at least one of ethane, propane, butane, pentane, and carbon dioxide. Additional injectants may include CO_2, natural gas, C5+ hydrocarbons, ketones, and alcohols. Non-solvent injectants may include steam, water, non-condensable gas, or hydrate inhibitors. The injected fluid may comprise at least one of diesel, viscous oil, natural gas, bitumen, diluent, C5+ hydrocarbons, ketones, alcohols, non-condensable gas, water, biodegradable solid particles, salt, water soluble solid particles, and solvent soluble solid particles.

[0040] To reach a desired injection pressure of the injected fluid, a viscosifer and/or a solvent slurry may be used in conjunction with the solvent. The viscosifer may be useful in adjusting solvent viscosity to reach desired injection pressures at available pump rates. The viscosifer may include diesel, viscous oil, bitumen, and/or diluent. The viscosifier may be in the liquid, gas, or solid phase. The viscosifer may be soluble in either one of the components of the injected solvent and water. The viscosifer may transition to the liquid phase in the reservoir before or during production. In the liquid phase, the viscosifers are less likely, to increase the viscosity of the produced fluids and/or decrease the effective permeability of the formation to the produced fluids.

[0041] The viscosifier may reduce the average distance the solvent travels from the well during an injection period. The viscosifer may act like a solvent and provide flow assurance near the wellbore and in the surface facilities in the event of asphaltene precipitation or solvent vaporization during shut-in periods. Solids suspended in the solvent slurry may comprise biodegradable solid particles, salt, water soluble solid particles, and/or solvent soluble solid particles.

[0042] The solvent may comprise greater than 50% C2-C5 hydrocarbons on a mass basis. The solvent may be greater than 50% propane, optionally with diluent when it is desirable to adjust the properties of the injectant to improve performance. Wells may be subjected to compositions other than these main solvents to improve well pattern performance, for example CO2 flooding of a mature operation.

[0043] The solvent may be as described in Canadian Patent No. 2,645,267 (Chakrabarty, issued April 16, 2013). The solvent may comprise (i) a polar component, the polar component being a compound comprising a non-terminal carbonyl group; and (ii) a non-polar component, the non-polar component being a substantially aliphatic substantially non-halogenated alkane. The solvent may have a Hansen hydrogen bonding parameter of 0.3 to 1.7 (or 0.7 to 1.4). The solvent may have a volume ratio of the polar component to non-polar component of 10:90 to 50:50 (or 10:90 to 24:76, 20:80 to 40:60, 25:75 to 35:65, or 29:71 to 31:69). The polar component may be, for instance, a ketone or acetone. The non-polar component may be, for instance, a C2-C7 alkane, a C2-C7 n-alkane, an n-pentane, an n-heptane, or a gas plant condensate comprising alkanes, naphthenes, and aromatics.

[0044] The solvent may be as described in Canadian Patent No. 2,781,273 (Chakrabarty, issued May 20, 2014). The solvent may comprise (i) an ether with 2 to 8 carbon atoms; and (ii) a non-polar hydrocarbon with 2 to 30 carbon atoms. Ether may have 2 to 8 carbon atoms. Ether may be di-methyl ether, methyl ethyl ether, di-ethyl ether, methyl iso-propyl ether, methyl propyl ether, di-isopropyl ether, di-propyl ether, methyl iso-butyl ether, methyl butyl ether, ethyl iso-butyl ether, ethyl butyl ether, iso-propyl butyl ether, propyl butyl ether, di-isobutyl ether, or di-butyl ether. Ether may be di-methyl ether. The non-polar hydrocarbon may a C2-C30 alkane. The non-polar hydrocarbon may be a C2-C5 alkane. The non-polar hydrocarbon may be propane. The ether may be di-methyl ether and the hydrocarbon may be propane. The volume ratio of ether to non-polar hydrocarbon may be 10:90 to 90:10; 20:80 to 70:30; or 22.5:77.5 to 50:50.

[0045] Phase of injected solvent

[0046] The solvent may be injected into the well at a pressure in the underground reservoir above a liquid/vapor phase change pressure such that at least 25 mass % of the solvent enters the reservoir in the liquid phase. At least 50, 70, or even 90 mass % of the solvent may enter the reservoir in the liquid phase. The percentage of solvent that may enter the reservoir in a liquid phase may be within a range that includes or is bounded by any of the preceding examples. Injection of the solvent as a liquid may be preferred for increasing injected fluid injection pressure. When injecting the solvent as a liquid pore dilation at high pressures is thought to be a particularly effective mechanism for permitting the solvent to enter into reservoirs filled with viscous oils when the reservoir comprises largely unconsolidated sand grains. When injecting the solvent as a liquid, higher overall injection rates than injection as a gas may be allowed.

[0047] A fraction of the solvent may be injected in the solid phase in order to mitigate adverse solvent fingering, increase injection pressure, and/or keep the average distance of the solvent closer to the wellbore than in the case of pure liquid phase injection. Less than 20 mass % of the injectant may enter the reservoir in the solid phase. Less than 10 mass % or less than 50 mass % of the solvent may enter the reservoir in the solid phase. The percentage of solvent that may enter the reservoir in a solid phase may be within a range that includes or is bounded by any of the preceding examples. Once in the reservoir, the solid phase of the solvent may transition to a liquid phase before or during production to prevent or mitigate reservoir permeability reduction during production.

[0048] Injection of the solvent as a vapor may assist uniform solvent distribution along a horizontal well, particularly when variable injection rates are targeted. Vapor injection in a horizontal well may facilitate an upsize in the port size of installed inflow control devices (ICDs) that minimize the risk of plugging the ICDs. Injecting the solvent as a vapor may increase the ability to pressurize the reservoir to a desired pressure by lowering effective permeability of the injected vapor in a formation comprising liquid viscous oil.

[0049] The solvent volume may be injected into the well at rates and pressures such that immediately after completing injection into the injection well during an injection period at least 25 mass % of the injected solvent is in a liquid state in the reservoir (e.g., underground).

[0050] A non-condensable gas may be injected into the reservoir to achieve a desired pressure, followed by injection of the solvent. Alternating periods of a primarily non-condensable gas with primarily solvent injection (where primarily means greater than 50% of the mixture of non-condensable gas and solvent) may provide a way to maintain the desired injection pressure target. The primarily gas injection period may offset the pressure leak off observed during primarily solvent injection to reestablish the desired injection pressure. The alternating strategy of condensable gas to solvent injection periods may result in non-condensable gas accumulations in the previous established solvent pathways. The accumulation of non-condensable gas may divert the subsequent primarily solvent injection to bypassed viscous oil thereby increasing the mixing of solvent and oil in the producing well's drainage area.

[0051] A non-solvent injectant in the vapor phase, such as CO_2 or natural gas, may be injected, followed by injection of a solvent. Depending on the pressure of the reservoir, it may be desirable to heat the solvent in order to inject it as a vapor. Heating of injected vapor or liquid solvent may enhance production through mechanisms described by "Boberg, T.C.

and Lantz, R.B., "Calculation of the production of a thermally stimulated well", *JPT*, 1613-1623, Dec. 1966. Towards the end of the injection period, a portion of the injected solvent, perhaps 25% or more, may become a liquid as pressure rises. After the targeted injection cycle volume of solvent is achieved, no special effort may be made to maintain the injection pressure at the saturation conditions of the solvent, and liquefaction may occur through pressurization, not condensation. Downhole pressure gauges and/or reservoir simulation may be used to estimate the phase of the solvent and non-solvent injectants at downhole conditions and in the reservoir. A reservoir simulation may be carried out using a reservoir simulator, a software program for mathematically modeling the phase and flow behavior of fluids in an underground reservoir. Those skilled in the art understand how to use a reservoir simulator to determine if 25% of the solvent would be in the liquid phase immediately after the completion of an injection period. Those skilled in the art may rely on measurements recorded using a downhole pressure gauge in order to increase the accuracy of a reservoir simulator. Alternatively, the downhole pressure gauge measurements may be used to directly make the determination without the use of reservoir simulation.

[0052] Although a CSDRP may be predominantly a non-thermal process in that heat is not used principally to reduce the viscosity of the viscous oil, the use of heat is not excluded. Heating may be beneficial to improve performance, improve process start-up, or provide flow assurance during production. For start-up, low-level heating (for example, less than 100ºC) may be appropriate. Low-level heating of the solvent prior to injection may also be performed to prevent hydrate formation in tubulars and in the reservoir. Heating to higher temperatures may benefit recovery. Two non-exclusive scenarios of injecting a heated solvent are as follows. In one scenario, vapor solvent would be injected and would condense before it reaches the bitumen. In another scenario, a vapor solvent would be injected at up to 200°C and would become a supercritical fluid at downhole operating pressure.

[0053] <u>Pore Volume</u>

[0054] Pore volume is discussed herein because it will be referred to below with respect to advance-retreat injection and production volumes.

[0055] As described in Canadian Patent No. 2,734,170 (Dawson *et al.*, issued September 24, 2013), one method of managing fluid injection in a CSDRP is for the cumulative volume injected over all injection periods in a given cycle ($V_{INJECTANT}$) to equal the net reservoir voidage ($V_{VOIDAGE}$) resulting from previous injection and production cycles plus an additional volume (V $_{ADDITIONAL}$), for example approximately 2-15%, or approximately 3-8% of the pore volume (PV) of the reservoir volume associated with the well pattern. In mathematical terms, the volume (V) may be represented by:

[0056] $$V_{INJECTANT} = V_{VOIDAGE} + V_{ADDITIONAL}.$$

[0057] One way to approximate the net in-situ volume of fluids produced is to determine the total volume of non-solvent liquid hydrocarbon fraction produced (V $_{PRODUCED\ OIL}$) and aqueous fraction produced (V $_{PRODUCED\ WATER}$) minus the net injectant fractions produced (V $_{INJECTED\ SOLVENT}$ - V $_{PRODUCED\ SOLVENT}$). For example, in the case where 100% of the injectant is solvent and the reservoir contains only oil and water, an equation that represents the net in-situ volume of fluids produced (V $_{VOIDAGE}$) is:

[0058] $$V_{VOIDAGE} = V_{OIL}^{PRODUCED} + V_{WATER}^{PRODUCED} - (V_{SOLVENT}^{INJECTED} - V_{SOLVENT}^{PRODUCED}).$$

[0059] Estimates of the PV are the reservoir volume inside a unit cell of a repeating well pattern or the reservoir volume inside a minimum convex perimeter defined around a set of wells in a given cycle. Fluid volume may be calculated at in-situ conditions, which take into account reservoir temperatures and pressures. If the application is for a single well, the "pore volume of the reservoir" is defined by an inferred drainage radius region around the well which is approximately equal to the distance that solvent fingers are expected to travel during the injection cycle (for example, about 30-200m). Such a distance may be estimated by reservoir surveillance activities, reservoir simulation or reference to prior observed field performance. In this approach, the pore volume may be estimated by direct calculation using the estimated distance, and injection ceased when the associated injection volume (2-15% PV) has been reached.

[0060] As described in the aforementioned Canadian Patent No. 2,734,170, rather than measuring pore volume directly, indirect measurements can be made of other parameters and used as a proxy for pore volume.

[0061] Diluent

[0062] In the context of this specification, diluent means a liquid compound that can be used to dilute the solvent and can be used to manipulate the viscosity of any resulting solvent-bitumen mixture. By such manipulation of the viscosity of the solvent-bitumen (and diluent) mixture, the invasion, mobility, and distribution of solvent in the reservoir can be controlled so as to increase viscous oil production.

[0063] The diluent is typically a viscous hydrocarbon liquid, especially a C4 to C20 hydrocarbon, or mixture thereof, may be locally produced and may be used to thin bitumen to pipeline specifications. Pentane, hexane, and heptane may be components of such diluents. Bitumen itself can be used to modify the viscosity of the injected fluid, often in conjunction with ethane solvent.

[0064] The diluent may have an average initial boiling point close to the boiling point of pentane (36°C) or hexane (69°C) though the average boiling point (defined further below) may change with reuse as the mix changes (some of the solvent originating among the recovered viscous oil fractions). More than 50% by volume of the diluent has an average boiling point lower than the boiling point of decane (174°C). More than 75% by volume, such as more than 80% by volume or more than 90% by weight of the diluent, may have an average boiling point between the boiling point of pentane and the boiling point of decane. The diluent may have an average boiling point close to the boiling point of hexane (69°C) or heptane (98°C), or even water (100°C).

[0065] More than 50% by weight of the diluent (such as more than 75% or 80% by weight or more than 90% by weight) may have a boiling point between the boiling points of pentane and decane. More than 50% by weight of the diluent may have a boiling point between the boiling points of hexane (69°C.) and nonane (151°C), particularly between the boiling points of heptane (98°C) and octane (126°C).

[0066] By average boiling point of the diluent, we mean the temperature at which half (by volume) of a starting amount of diluent has been boiled off as described in section 15.1 and shown in Table 6 of ASTM D7096-10 (Standard Test Method for Determination of the Boiling Range Distribution of Gasoline by Wide-Bore Capillary Gas Chromatography). The average boiling point can be determined by gas chromatographic methods or more tediously by distillation. Boiling points are defined as the boiling points at atmospheric pressure.

[0067] Table 2 outlines the operating ranges for certain CSDRPs. The present disclosure is not intended to be limited by such operating ranges.

[0001] Table 2. Operating Ranges for a CSDRP.

Parameter	Broader Option	Narrower Option
Cumulative injectant volume per cycle	Fill-up estimated pattern pore volume plus a cumulative 3-8% of estimated pattern pore volume; or inject, beyond a primary pressure threshold, for a cumulative period of time (e.g. days to months); or inject, beyond a primary pressure threshold, a cumulative of 3-8% of estimated pore volume.	Inject a cumulative volume in a cycle, beyond a primary pressure threshold, of 3-8% of estimated pore volume.
Injectant composition, main	Main solvent (>50 mass%) C_2-C_5. Alternatively, wells may be subjected to compositions other than main solvents to improve well pattern performance (i.e. CO_2 flooding of a mature operation or altering *in-situ* stress of reservoir). CO_2	Main solvent (>50 mass%) is propane (C_3).
Injectant composition, additive	Additional injectants may include CO_2 (up to about 30 mass%), C_{3+}, viscosifiers (e.g. diesel, viscous oil, bitumen, diluent), ketones, alcohols, sulphur dioxide, hydrate inhibitors, steam, non-condensable gas, biodegradable solid particles, salt, water soluble solid particles, or solvent soluble solid particles.	Only diluent, and only when needed to achieve adequate injection pressure. Or, a polar compound having a non-terminal carbonyl group (e.g. a ketone, for instance acetone).

Injectant phase & Injection pressure	Solvent injected such that at the end of the injection cycle, greater than 25% by mass of the solvent exists as a liquid and less than 50% by mass of the injectant exists in the solid phase in the reservoir, with no constraint as to whether most solvent is injected above or below dilation pressure or fracture pressure.	Solvent injected as a liquid, and most solvent injected just under fracture pressure and above dilation pressure, $P_{fracture} > P_{injection} > P_{dilation} > P_{vapor}$.
Injectant temperature	Enough heat to prevent hydrates and locally enhance wellbore inflow consistent with Boberg-Lantz mode	Enough heat to prevent hydrates with a safety margin, $T_{hydrate}$ + 5°C to $T_{hydrate}$ +50°C.
Injection rate during continuous injection	0.1 to 10 m^3/day per meter of completed well length (rate expressed as volumes of liquid solvent at reservoir conditions).	0.2 to 6 m^3/day per meter of completed well length (rate expressed as volumes of liquid solvent at reservoir conditions). Rates may also be designed to allow for limited or controlled fracture extent, at fracture pressure or desired solvent conformance depending on reservoir properties.
Threshold pressure (pressure at which solvent continues to be injected for either a period of time or in a volume amount)	Any pressure above initial reservoir pressure.	A pressure between 90% and 100% of fracture pressure.

Well length	As long of a horizontal well as can practically be drilled; or the entire pay thickness for vertical wells.	500m – 1500m (commercial well).
Well configuration	Horizontal wells parallel to each other, separated by some regular spacing of 20 – 1000m. Also vertical wells, high angle slant wells & multi-lateral wells. Also infill injection and/or production wells (of any type above) targeting bypassed hydrocarbon from surveillance of pattern performance.	Horizontal wells parallel to each other, separated by some regular spacing of 50 – 600m.
Well orientation	Orientated in any direction.	Horizontal wells orientated perpendicular to (or with less than 30 degrees of variation) the direction of maximum horizontal *in-situ* stress.
Minimum producing pressure (MPP)	Generally, the range of the MPP should be, on the low end, a pressure significantly below the vapor pressure, ensuring vaporization; and, on the high-end, a high pressure near the native reservoir pressure. For example, perhaps 0.1 MPa (megapascals)– 5 MPa, depending on depth and mode of operation (all-liquid or limited vaporization).	A low pressure below the vapor pressure of the main solvent, ensuring vaporization, or, in the limited vaporization scheme, a high pressure above the vapor pressure. At 500m depth with pure propane, 0.5 MPa (low) – 1.5 MPa (high), values that bound the 800 kPa vapor pressure of propane.

Oil rate	Switch to injection when rate equals 2 to 50% of the max rate obtained during the cycle; Alternatively, switch when absolute rate equals a pre-set value. Alternatively, well is unable to sustain hydrocarbon flow (continuous or intermittent) by primary production against backpressure of gathering system or well is "pumped off" unable to sustain flow from artificial lift. Alternatively, well is out of sync with adjacent well cycles.	Switch when the instantaneous oil rate declines below the calendar day oil rate (CDOR) (e.g. total oil/total cycle length). Likely most economically optimal when the oil rate is at about 0.8 x CDOR. Alternatively, switch to injection when rate equals 20-40% of the max rate obtained during the cycle.
Gas rate	Switch to injection when gas rate exceeds the capacity of the pumping or gas venting system. Well is unable to sustain hydrocarbon flow (continuous or intermittent) by primary production against backpressure of gathering system with/or without compression facilities.	Switch to injection when gas rate exceeds the capacity of the pumping or gas venting system. During production, an optimal strategy is one that limits gas production and maximizes liquid from a horizontal well.
Oil to Solvent Ratio	Begin another cycle if the OISR of the just completed cycle is above 0.15 or economic threshold.	Begin another cycle if the OISR of the just completed cycle is above 0.3.

Abandonment pressure (pressure at which well is produced after CSDRP cycles are completed)	Atmospheric or a value at which all of the solvent is vaporized. Steps e) and f) (described below) may start from this point at the same or higher pressure.	For propane and a depth of 500m, about 340 kPa, the likely lowest obtainable bottomhole pressure at the operating depth and well below the value at which all of the propane is vaporized. Steps e) and f) (described below) may start from this point at the same or higher pressure.

[0068] In Table 2, the options may be formed by combining two or more parameters and, for brevity and clarity, each of these combinations will not be individually listed.

[0069] Recovering Residual Hydrocarbons

[0070] The foregoing has described a process for recovering hydrocarbons that may comprise (a) injecting (202) injected fluid comprising greater than 50 mass % of a viscosity-reducing solvent into an injection well completed in the underground reservoir; (b) halting injection (204) into the injection well and subsequently producing at least a fraction of the injected fluid and the hydrocarbons from the underground reservoir through a production well; (c) halting production (206) through the production well; and (d) repeating (208) the cycle of steps (a) to (c).

[0071] The foregoing process may leave valuable residual hydrocarbons in the ground. To recover residual hydrocarbons, a process in addition to steps (a) to (d) may comprise (e) injecting (210) a flooding fluid into the injection well to move residual hydrocarbons in the underground reservoir towards a flooding production well horizontally spaced form the injection and productions wells.

[0072] Injecting the flooding fluid may begin after any suitable number of cycles of steps (a) to (c), for instance at least 3, or 3 to 10. The cycle number after which a given well is subjected to step (e) may be determined by the percentage (%) of cumulative volume of the hydrocarbons produced relative to original hydrocarbons in place (OHIP) surrounding the well, for instance at 15, 20, 25, 30, 35, or 40 volume % of OHIP. The cycle number after which a given well is subjected to step (e) may be the cycle at which the solvent injected to hydrocarbons produced ratio makes any more cycles of (a) to (c) uneconomic, for instance at an injected solvent to hydrocarbons produced ratio of 2.5, 3, 3.5, or 4. The cycle number after which a given well is subjected to step (e) may be the cycle after which the ratio of the volume of hydrocarbons produced to solvent lost in the reservoir is less than a certain value, for instance less than 2. The cycle number after which a given well is subjected to step (e) may be the cycle at which the cumulative hydrocarbons produced from the injection well and its partner production well for flooding is high enough to indicate flooding is possible without exceeding the allowable injection pressure, which may be determined by a maximum operating pressure rating of a pump, or related to the reservoir pressure.

[0073] In addition to using cumulative hydrocarbons as an indicator to initiate injecting the flooding fluid, other reservoir surveillance techniques, including 4-D seismic may be used. 4-D seismic uses sound waves to form three-dimensional images of an underground reservoir over different time periods to locate bypassed oil by step (a) to (c).

[0074] The flooding fluid may be any suitable flooding fluid. The flooding fluid may comprise at least one of ethane, propane, butane, pentane, carbon dioxide, dimethyl ether, propyl acetate ester, acetone, and steam.

[0075] The flooding fluid may be injected at any suitable temperature. For example, the flooding fluid may be injected at reservoir temperature (for instance 10°C) to about 311°C. 311°C is steam temperature at 10 MPa (megapascals).

[0076] The flooding fluid may comprise steam in any suitable amount, for instance 2-98 weight % steam. The steam may be any suitable quality, for instance from 0 to100% vapor. The steam proportion in the flooding fluid may be determined by the viscosity of the bypassed hydrocarbons and the amount of bypassed hydrocarbons before step (e) is initiated. The higher the viscosity of the hydrocarbons and/or the higher the amount of bypassed hydrocarbons, the higher the steam content may be. The steam may be injected at a pressure of about 10 MPaa (megapascal absolute) or lower.

[0077] The flooding fluid may comprise non-condensable gases that do not condense to liquid in the reservoir in order to provide drive energy or maintain pressure. The non-condensable gases may be any suitable non-condensable gases, for instance at least one of nitrogen, carbon dioxide, air, natural gas, methane, ethane, and propane.

[0078] The production flooding well(s) may be at the same depth or at a greater depth than the injection well(s). In this way, gravity may assist the flooding. The injection well(s) may be at the same depth or at a greater depth than production flooding well(s). The flooding production well may be at approximately the same depth as the injection well, for instance within 10 vertical meters of the injection well, or at an angle of less than 10 degrees from horizontal from the injection well (where 0 degrees indicates equal depth). In order to use the effect of gravity, the flooding production well may be 10 to 100 meters deeper than the injection well, or deeper than the injection well by an angle of greater than 10 degrees from horizontal (where 0 degrees indicates equal depth).

[0079] The flooding production well may be horizontally spaced from the injection well and the productions well by 50 to 200 meters. The distance may allow for fluid communication between the injection well and the flooding production well.

[0080] The flooding production well may be a production well of a CSDRP for instance as described above with steps (a) to (d). The CSDRP may be a process including steps (a) to (d) described above.

[0081] To recover residual hydrocarbons, a process in addition to steps (a) to (e) may comprise (f) producing (212) at least a fraction of the flooding fluid and at least a fraction of the residual hydrocarbons through the production flooding well. The injection well and the flooding production well need not be matched in a one to one relationship. For instance, a flooding fluid may be injected into one injection well and flood to two or more flooding production wells. Conversely, a flooding fluid may be injected into two or more injection wells and flood to one flooding production well.

[0082] All the wells in a given location may be converted to flooding at one time. Alternatively, for instance, certain well pairs on steps (a) to c) may be on flooding steps (e) and (f), while others may remain on steps (a) to (d). That is, steps (e) and (f) may be performed simultaneously on two or more well pairs or sequentially on two of more well pairs.

[0083] It may be desirable that the injected flooding fluid contacts bypassed hydrocarbons rather than simply being produced in order to recover hydrocarbons. Certain wells may therefore be shut-in or choked to increase contact with bypassed hydrocarbons.

[0084] It should be understood that numerous changes, modifications, and alternatives to the preceding disclosure can be made without departing from the scope of the disclosure. The preceding description, therefore, is not meant to limit the scope of the disclosure. Rather, the scope of the disclosure is to be determined only by the appended claims and their equivalents. It is also contemplated that structures and features in the present examples can be altered, rearranged, substituted, deleted, duplicated, combined, or added to each other.

CLAIMS:

1. A process for recovering hydrocarbons from an underground reservoir, the process comprising:

(a) injecting injected fluid, comprising greater than 50 mass % of a viscosity-reducing solvent, into an injection well completed in the underground reservoir;

(b) halting injection into the injection well and subsequently producing at least a fraction of the injected fluid and the hydrocarbons from the underground reservoir through a production well;

(c) halting production through the production well;

(d) repeating steps (a) to (c);

(e) injecting a flooding fluid into the injection well to move residual hydrocarbons in the underground reservoir towards a flooding production well horizontally spaced from the injection well and the production well; and

(f) producing at least a fraction of the flooding fluid and at least a fraction of the residual hydrocarbons through the flooding production well;

wherein step (e) begins after 15 volume % of hydrocarbons in place have been produced.

2. The process of claim 1, wherein the flooding fluid comprises at least one of ethane, propane, butane, pentane, carbon dioxide, dimethyl ether, propyl acetate ester, acetone, and steam.

3. The process of claim 1 or 2, wherein the flooding fluid is injected at a temperature of reservoir temperature to 311°C.

4. The process of claim 2 or 3, wherein the flooding fluid comprises steam.

5. The process of any one of claims 2 to 4, wherein the flooding fluid comprises 2-98 weight % steam.

6. The process of any one of claims 2 to 5, wherein the steam is injected at a pressure below 10 MPa.

Date Reçue/Date Received 2021-05-31

7. The process of claim 5, wherein the flooding fluid further comprises non-condensable gases that do not condense to liquid in the underground reservoir.

8. The process of claim 7, wherein the non-condensable gases comprise at least one of nitrogen, carbon dioxide, air, natural gas, methane, ethane, and propane.

9. The process of any one of claims 1 to 8, wherein the flooding production well is 10 to 100 meters deeper than the injection well.

10. The process of any one of claims 1 to 8, wherein the flooding production well is 0 to 10 meters deeper than the injection well.

11. The process of any one of claims 1 to 10, wherein the flooding production well is horizontally spaced from the injection well and the production well by 50 to 200 meters.

12. The process of any one of claims 1 to 10, wherein the flooding production well is a production well of a cyclic solvent solvent-dominated recovery process.

13. The process of claim 12, wherein the cyclic solvent solvent-dominated recovery process is a process including steps (a) to (d).

14. The process of any one of claims 1 to 13, wherein steps (e) and (f) are performed simultaneously in two or more well pairs.

15. The process of any one of claims 1 to 13, wherein steps (e) and (f) are performed sequentially in two or more well pairs.

16. The process of any one of claims 1 to 15, wherein step (e) begins after at least 3 cycles of steps (a) to (c).

17. The process of any one of claims 1 to 15, wherein step (e) begins after 3 to 10 cycles of steps (a) to (c).

Date Reçue/Date Received 2021-05-31

18. The process of any one of claims 1 to 17, wherein step (e) begins after a ratio of injected viscosity-reducing solvent to produced hydrocarbons reaches 2.5.

19. The process of any one of claims 1 to 17, wherein step (e) begins after a ratio of produced hydrocarbons to viscosity-reducing solvent lost in the underground reservoir is less than 2.

20. The process of any one of claims 1 to 19, wherein the injection well and the production well utilize a common wellbore.

21. The process of any one of claims 1 to 20, wherein the hydrocarbons are a viscous oil having a viscosity of at least 10 cP at initial reservoir conditions.

22. The process of any one of claims 1 to 21, wherein the viscosity-reducing solvent comprises at least one of ethane, propane, butane, pentane, and carbon dioxide.

23. The process of any one of claims 1 to 22, wherein the injected fluid comprises at least one of diesel, viscous oil, natural gas, bitumen, diluent, C5+ hydrocarbons, ketones, alcohols, non-condensable gas, water, biodegradable solid particles, salt, water soluble solid particles, and solvent soluble solid particles.

24. The process of any one of claims 1 to 23, wherein the injected fluid comprises at least 25 mass % liquid at the end of an injection cycle.

25. The process of any one of claims 1 to 24, wherein the injected fluid comprises less than 50 mass % solid at the end of an injection cycle.

26. The process of any one of claims 1 to 25, wherein at least 25 mass % of the viscosity-reducing solvent in an injection cycle enters the reservoir as a liquid.

27. The process of any one of claims 1 to 26, wherein at least 25 mass % of the viscosity-reducing solvent at the end of an injection cycle is a liquid.

Date Reçue/Date Received 2021-05-31

28. The process of any one of claims 1 to 27, wherein an in-situ volume of fluid injected over a cycle is equal to a net in-situ volume of fluids produced from the production well summed over all preceding cycles plus an additional in-situ volume of fluid.

29. The process of claim 28, wherein the additional in-situ volume of fluid is, at reservoir conditions, equal to 2% to 15% of a pore volume within a reservoir zone around the injection well within which solvent fingers are expected to travel during the cycle.

Date Reçue/Date Received 2021-05-31

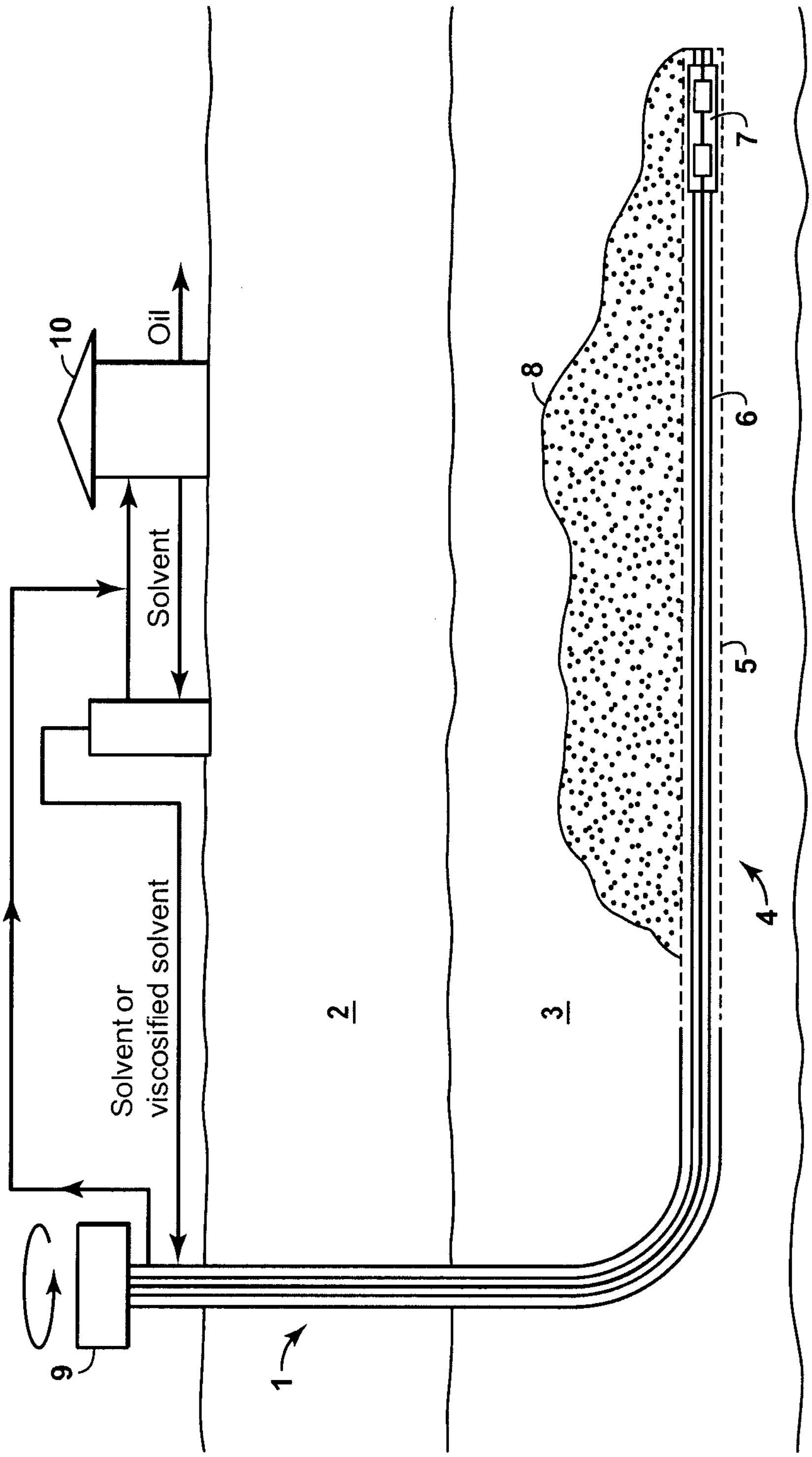


FIG. 1
(Prior Art)

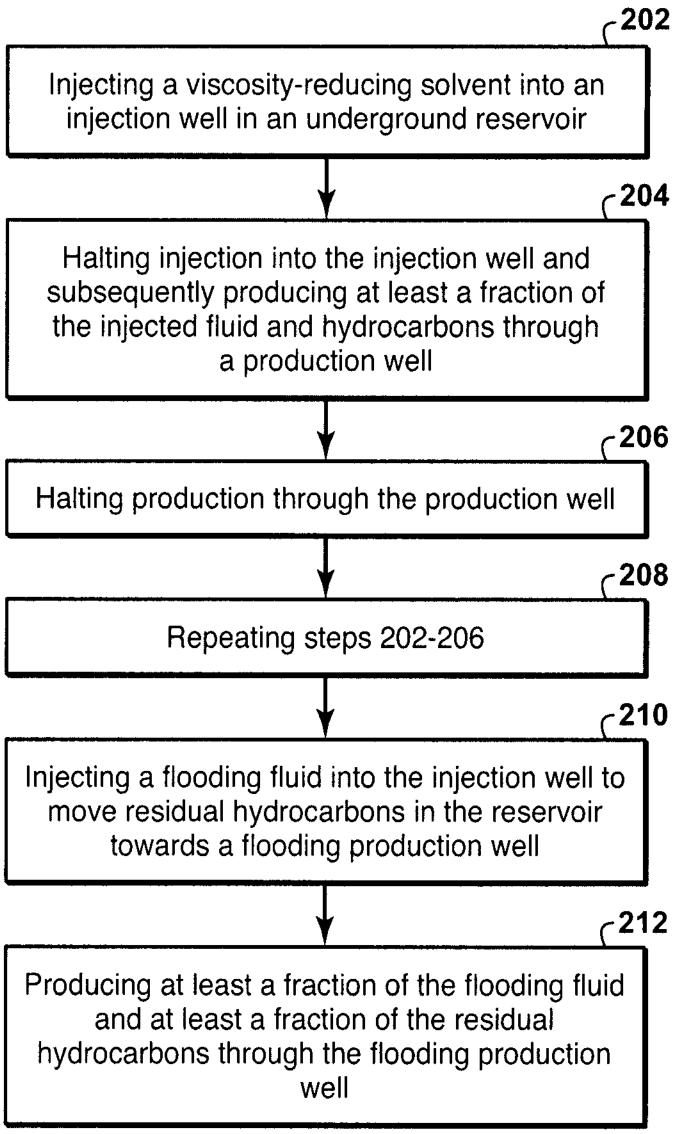
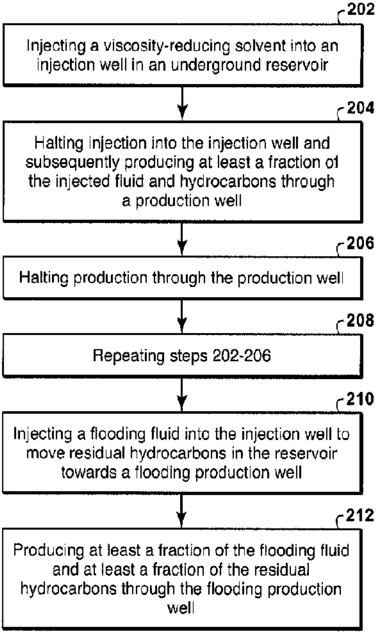

202
Injecting a viscosity-reducing solvent into an injection well in an underground reservoir
204
Halting injection into the injection well and subsequently producing at least a fraction of the injected fluid and hydrocarbons through a production well
206
Halting production through the production well
208
Repeating steps 202-206
210
Injecting a flooding fluid into the injection well to move residual hydrocarbons in the reservoir towards a flooding production well
212
Producing at least a fraction of the flooding fluid and at least a fraction of the residual hydrocarbons through the flooding production well

FIG. 2


202
Injecting a viscosity-reducing solvent into an injection well in an underground reservoir
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Halting injection into the injection well and subsequently producing at least a fraction of the injected fluid and hydrocarbons through a production well
206
Halting production through the production well
208
Repeating steps 202-206
210
Injecting a flooding fluid into the injection well to move residual hydrocarbons in the reservoir towards a flooding production well
212
Producing at least a fraction of the flooding fluid and at least a fraction of the residual hydrocarbons through the flooding production well