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(54) **RECOVERY FROM A HYDROCARBON RESERVOIR**

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(57) **ABSTRACT**

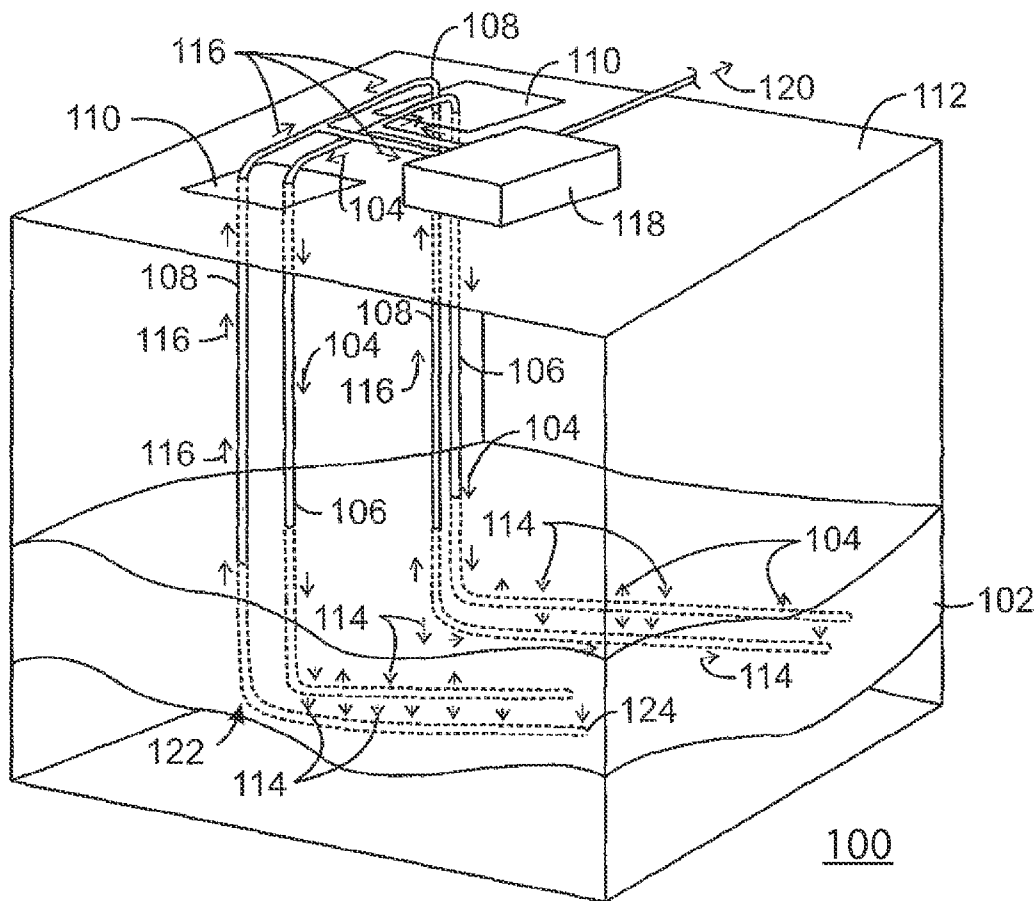
Methods and systems for recovering heavy oil, such as bitumen, by steam assisted gravity drainage (SAGD) from subterranean formations having a water and/or gas containing layer overlying a heavy oil containing layer. A fluid blocking agent is injected into the water and/or gas containing layer above at least one pair of horizontal wells. The blocking agent undergoes a change of density, viscosity or solidity when elevated to a temperature between an initial ambient reservoir temperature and 175 degrees by heat from steam used in the SAGD process, thereby creating a seal within the reservoir above the at least one pair of horizontal wells limiting or preventing movements of fluid through the seal.

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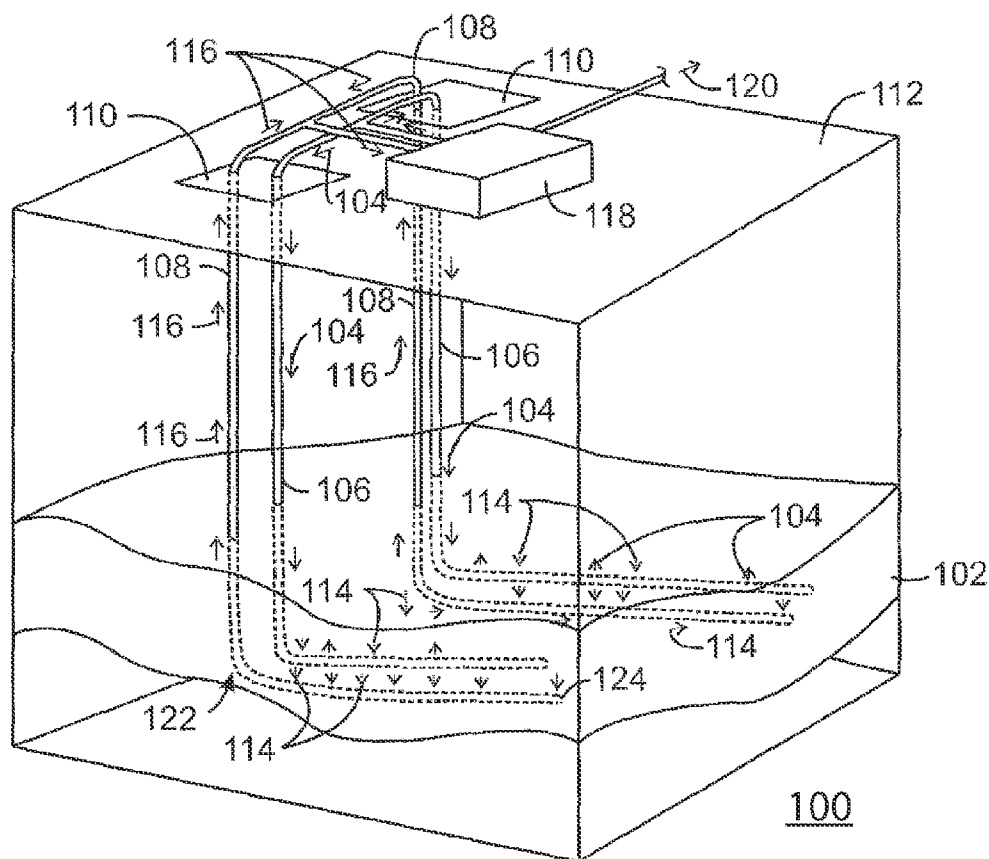


FIG. 1

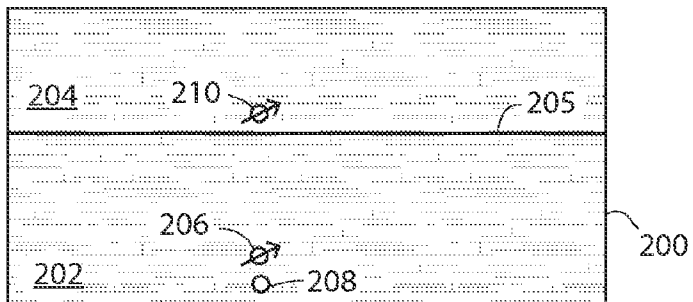


Fig. 2A

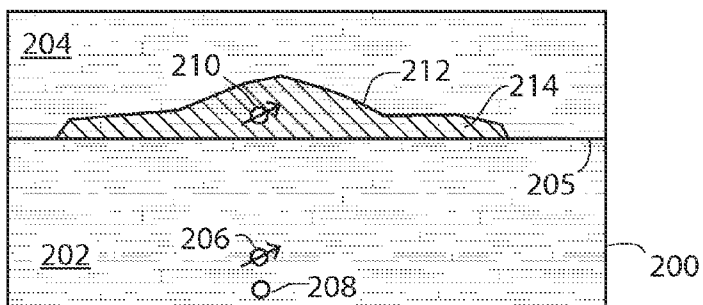


Fig. 2B

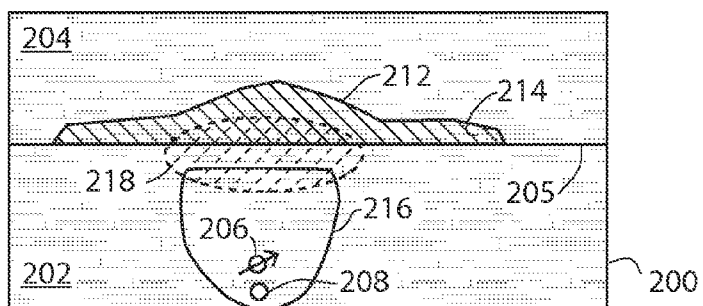


Fig. 2C

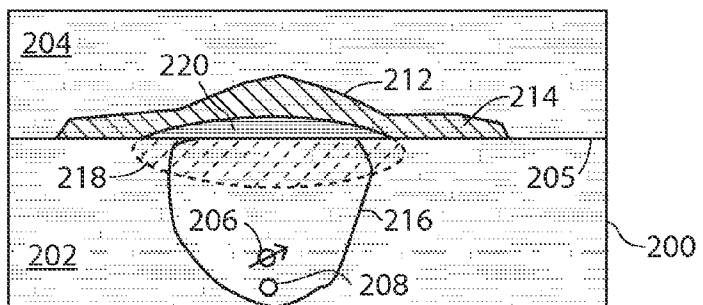


Fig. 2D

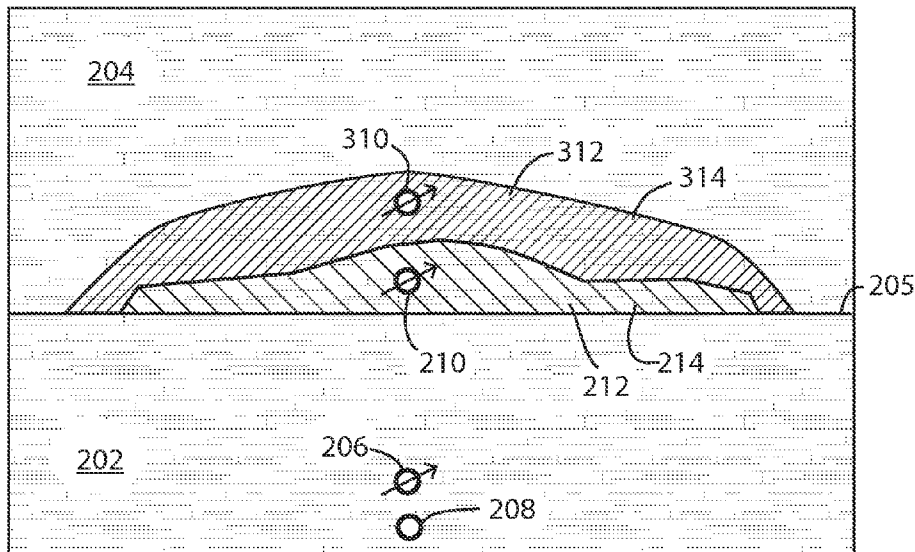


Fig. 3A

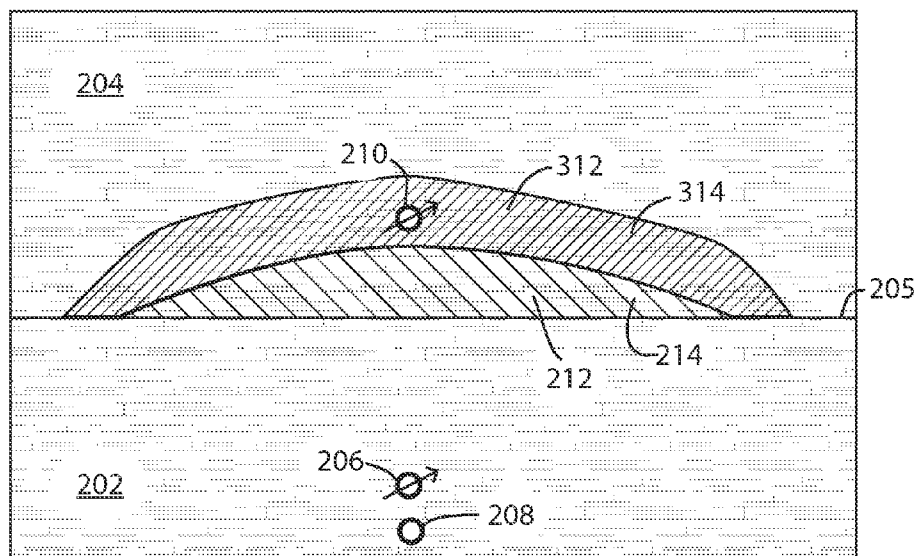


Fig. 3B

RECOVERY FROM A HYDROCARBON RESERVOIR

CROSS REFERENCE TO RELATED APPLICATIONS

[0001] This application claims the priority benefit of Canadian Patent Application number 2,830,741 filed Oct. 23, 2013 entitled IMPROVING RECOVERY FROM A HYDROCARBON RESERVOIR, the entirety of which is incorporated by reference herein.

FIELD

[0002] The present disclosure relates to harvesting hydrocarbon resources using gravity drainage processes. Specifically, improved methods are disclosed involving steam assisted gravity drainage of heavy oil from underground reservoirs.

BACKGROUND

[0003] 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.

[0004] Modern society is greatly dependent on the use of hydrocarbons for fuels and chemical feedstocks. Hydrocarbons are generally found in subsurface rock formations that can be termed "reservoirs." Removing hydrocarbons from the reservoirs depends on numerous physical properties of the rock formations, such as the permeability of the rock, sand or soil containing the hydrocarbons, the ability of the hydrocarbons to flow through the rock, sand or soil formations, and the proportion of hydrocarbons present, among other things.

[0005] Easily harvested sources of hydrocarbon are dwindling, leaving less-accessible sources to satisfy future energy needs. However, as the costs of hydrocarbons increase, these less-accessible sources become more economically attractive. For example, the harvesting of oil sands to remove hydrocarbons has become more extensive as it has become more economical. The hydrocarbons harvested from these reservoirs may have relatively high viscosities, for example, ranging from 8 degrees API, or lower, up to 20 degrees API, or higher. Accordingly, the hydrocarbons may include heavy oils, bitumen, or other carbonaceous materials, collectively referred to herein as "heavy oil," which are difficult to recover using standard techniques.

[0006] Several methods have been developed to remove hydrocarbons from reservoirs oil sands. For example, strip or surface mining may be performed to access the oil sands, which can then be treated with hot water or steam to extract the oil. However, deeper formations may not be accessible using a strip mining approach. For these formations, a well can be drilled into the reservoir and steam, hot air, solvents, or combinations thereof, can be injected to release the hydrocarbons. The released hydrocarbons may then be collected by the injection well or by other wells (i.e. production wells) and brought to the surface.

[0007] A number of techniques have been developed for harvesting heavy oil from subsurface formations using well-based recovery techniques. These operations include a suite of steam based in-situ thermal recovery techniques, such as

cyclic steam stimulation (CSS), steam flooding and steam assisted gravity drainage (SAGD) as well as surface mining and their associated thermal based surface extraction techniques.

[0008] Various embodiments of the SAGD process are described in Canadian Patent No. 1,304,287 to Butler and U.S. Pat. No. 4,344,485. In SAGD, two horizontal wells are completed into the reservoir. The two wells are first drilled vertically to different depths within the reservoir. Thereafter, using directional drilling technology, the two wells are extended in the horizontal direction that result in two horizontal wells, vertically spaced from, but otherwise vertically aligned with the other. Ideally, the production well is located above the base of the reservoir but as close as practical to the bottom of the reservoir, and the injection well is located vertically 10 to 30 feet (3 to 10 meters) above the horizontal well used for production.

[0009] The upper horizontal well is utilized as an injection well and is supplied with steam from the surface. The steam rises from the injection well, permeating the reservoir to form a vapor chamber (steam chamber) that grows over time towards the top of the reservoir, thereby increasing the temperature within the reservoir. The steam, and its condensate, raise the temperature of the reservoir and consequently reduce the viscosity of the heavy oil in the reservoir. The heavy oil and condensed steam will then drain downwardly through the reservoir under the action of gravity and may flow into the lower production well, from which these liquids can be pumped to the surface. At the surface of the well, the condensed steam and heavy oil are separated, and the heavy oil may be diluted with appropriate light hydrocarbons for transport by pipeline.

[0010] Significant portions of oil sands, at least in the Athabasca region of Canada, have either water zones (water-containing sands) positioned on top of the heavy oil bearing sands or have gas caps (zones of gas-containing ground overlying the heavy oil bearing sands), or combinations of the two (layers containing both water and gas). These zones may act as "thief zones" into which steam can be lost or channeled away from the target depletion zone (the heavy oil bearing layers), or they may cause cold water to permeate the heavy oil-bearing layers, thus reducing the reservoir temperature. This can severely degrade the performance of SAGD processes and may be detrimental to the economics of the development project. Where there is a top water zone, steam will rise up into the water zone and cold water from the top water zone may drain down into the well. Where there is a gas cap, if the gas cap is at low pressure, this will limit the pressure of the SAGD process, and it may not be economical to operate SAGD at such a low pressure due to consequent lower production rates.

SUMMARY

[0011] A method of recovering heavy oil from a hydrocarbon reservoir in which a water and/or gas containing layer overlies a heavy oil containing layer, may comprise providing an injection well in the water and/or gas containing layer above at least one pair of horizontal wells in the heavy oil containing layer for heavy oil recovery by a steam assisted gravity drainage process, injecting a blocking agent into the water and/or gas containing layer via the injection well to form a region of the water and/or gas containing layer containing the blocking agent adjacent an interface between the water and/or gas containing layer and the heavy oil containing

layer above the at least one pair of horizontal wells, and operating the steam assisted gravity drainage process via the at least one pair of wells by injecting steam into the heavy oil containing layer and recovering heavy oil from the heavy oil containing layer. The blocking agent is injected into the water and/or gas containing layer before operating the steam assisted gravity drainage process or before heat generated by the steam assisted gravity drainage process reaches the region of the water and/or gas containing layer that will contain the blocking agent. The blocking agent, when present in the region, undergoes a change of viscosity, density or solidity when elevated to a temperature between an initial ambient reservoir temperature in the region and 175° C. by heat from steam used in the process, and thereby creates a seal within the reservoir above the at least one pair of horizontal wells limiting or preventing movements of fluid through the seal.

[0012] 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.

DESCRIPTION OF THE DRAWINGS

[0013] These and other features, aspects and advantages of the present disclosure will become apparent from the following description, appending claims and the accompanying drawings, which are briefly discussed below.

[0014] FIG. 1 is a drawing of a steam assisted gravity drainage process.

[0015] FIGS. 2A to 2D illustrate steps in a method of heavy oil recovery.

[0016] FIGS. 3A and 3B illustrate steps in a method of heavy oil recovery.

[0017] 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 the purpose of convenience and clarity in illustrating various aspects of the disclosure.

DETAILED DESCRIPTION

[0018] For the purpose of promoting an understanding of the principles of the disclosure, reference will now be made to the features 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.

[0019] At the outset, for ease of reference, certain terms used in this application and their meanings as used in this context are set forth. 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. Further, the present techniques are not limited by the usage of the terms shown below, as all equivalents, synonyms, new developments, and terms or techniques that serve the same or a similar purpose are considered to be within the scope of the present claims.

[0020] “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 wt. % 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 metals content, while small, must be removed to avoid contamination of the product synthetic crude oil (SCO). Nickel can vary from less than 75 ppm (part per million) to more than 200 ppm. Vanadium can range from less than 200 ppm to more than 500 ppm. The percentage of the hydrocarbon types found in bitumen can vary. As used herein, the term “heavy oil” includes bitumen, as well as lighter materials that may be found in a sand or carbonate reservoir. Heavy oil may have a viscosity of about 1000 cP or more, 10,000 cP or more, 100,000 cP or more or 1,000,000 cP or more.

[0021] As used herein, two locations in a reservoir are in “fluid communication” when a path for fluid flow exists between the locations. For example, fluid communication between a production well and an overlying steam chamber can allow mobilized material to flow down to the production well for collection and production. As used herein, a fluid includes a gas or a liquid and may include, for example, a produced hydrocarbon, an injected mobilizing fluid, or water, among other materials.

[0022] “Facility” as used in this description is a tangible piece of physical equipment through which hydrocarbon fluids are either produced from a reservoir or injected into a reservoir, or equipment which can be used to control production or completion operations. In its broadest sense, the term facility is applied to any equipment that may be present along the flow path between a reservoir and its delivery outlets. Facilities may comprise production wells, injection wells, well tubulars, wellhead equipment, gathering lines, manifolds, pumps, compressors, separators, surface flow lines, steam generation plants, processing plants, and delivery outlets. In some instances, the term “surface facility” is used to distinguish those facilities other than wells.

[0023] “Heavy oil” includes oils which are classified by the American Petroleum Institute (API), as heavy oils, extra heavy oils, or bitumens. Thus the term “heavy oil” includes bitumen and should be regarded as such throughout this description. In general, a heavy oil has an API gravity between 22.30 (density of 920 kg/m³ or 0.920 g/cm³) and 10.00° (density of 1,000 kg/m³ or 1 g/cm). An extra heavy oil, in general, has an API gravity of less than 10.00° (density greater than 1,000 kg/m³ or greater than 1 g/cm). For example, a source of heavy oil includes oil sand or bituminous sand, which is a combination of clay, sand, water, and bitumen. The thermal recovery of heavy oils is based on the viscosity decrease of fluids with increasing temperature or solvent concentration. Once the viscosity is reduced, the mobilization of fluids by steam, hot water flooding, or gravity

is possible. The reduced viscosity makes the drainage quicker and therefore directly contributes to the recovery rate.

[0024] A “hydrocarbon” is an organic compound that primarily includes the elements hydrogen and carbon, although nitrogen, sulfur, oxygen, metals, or any number of other elements may be present in small amounts. As used herein, hydrocarbons generally refer to components found in heavy oil or in oil sands. However, the techniques described herein are not limited to heavy oils, but may also be used with any number of other reservoirs to improve gravity drainage of liquids.

[0025] “Permeability” is the capacity of a rock to transmit fluids through the interconnected pore spaces of the rock. The customary unit of measurement for permeability is the millidarcy.

[0026] “Pressure” is the force exerted per unit area by the gas on the walls of the volume. Pressure may be shown in this disclosure as pounds per square inch (psi), kilopascals (kPa) or megapascals (MPa). Unless otherwise specified, the pressures disclosed herein are absolute pressures, i.e. the sum of gauge pressure plus atmospheric pressure (generally 14.7 psi at standard conditions).

[0027] As used herein, a “reservoir” is a subsurface rock or sand formation from which a production fluid, or resource, can be harvested. The rock formation may include sand, granite, silica, carbonates, clays, and organic matter, such as bitumen, heavy oil, oil, gas, or coal, among others. Reservoirs can vary in thickness from less than one foot (0.3048 m) to hundreds of feet (hundreds of m). The resource is generally a hydrocarbon, such as a heavy oil impregnated into a sand bed.

[0028] As discussed herein, “Steam Assisted Gravity Drainage” (SAGD), is a thermal recovery process in which steam, or combinations of steam and solvents, is injected into a first well to lower a viscosity of a heavy oil, and fluids are recovered from a second well. Both wells are generally horizontal in the formation and the first well lies above the second well. Accordingly, the reduced viscosity heavy oil flows down to the second well under the force of gravity, although pressure differential may provide some driving force in various applications. Although SAGD is used as an exemplary process herein, it can be understood that the techniques described can include any gravity driven process, such as those based on steam, solvents, or any combinations thereof.

[0029] “Substantial” when used in reference to a quantity or amount of a material, or a specific characteristic thereof, refers to an amount that is sufficient to provide an effect that the material or characteristic was intended to provide. The exact degree of deviation allowable may in some cases depend on the specific context.

[0030] “Thermal recovery processes” include any type of hydrocarbon recovery process that uses a heat source to enhance the recovery, for example, by lowering the viscosity of a hydrocarbon. These processes may use injected mobilizing fluids, such as hot water, wet steam, dry steam, or solvents alone, or in any combinations, to lower the viscosity of the hydrocarbon. Such processes may include subsurface processes, such as cyclic steam stimulation (CSS), cyclic solvent stimulation, steam flooding, solvent injection, and SAGD, among others, and processes that use surface processing for the recovery, such as sub-surface mining and surface mining. Any of the processes referred to herein, such as SAGD, may be used in concert with solvents.

[0031] A “wellbore” is a hole in the subsurface made by drilling or inserting a conduit into the subsurface. A wellbore

may have a substantially circular cross section or any other cross-sectional shape, such as an oval, a square, a rectangle, a triangle, or other regular or irregular shapes. As used herein, the term “well,” when referring to an opening in the formation, may be used interchangeably with the term “wellbore.” Further, multiple pipes may be inserted into a single wellbore, for example, as a liner configured to allow flow from an outer chamber to an inner chamber.

[0032] “Thermally and/or chemically-activated blocking agents” are materials that are flowable through the porous medium of a reservoir when injected into the porous medium of the reservoir and that, when activated by a change of temperature or chemical reaction, solidify, densify or gel, or shed a solid precipitate, and thus block pores in the reservoir to hinder or prevent the passage of gas or water through the reservoir.

[0033] A “steam chamber” is a region of a heavy oil containing layer of a reservoir that forms around a steam injection well and that is generally at or close to the temperature of steam at the pressures within the reservoir. The chamber may comprise pores from which heavy oil has at least partially flowed upon being heated by the steam to be replaced at least in part by steam itself. In practice, heavy oil containing layers may not necessarily have pores containing 100% heavy oil and may naturally contain only 70-80 vol. % heavy oil with the remainder usually water. In contrast, a water and/or gas containing layer may comprise 100% water and/or gas in the pores, but normally contains 5-70 vol. % gas and 20-30 vol. % water with any remainder being heavy oil.

[0034] For a better understanding of the techniques of the present disclosure, a brief explanation of one form of steam assisted gravity drainage is first provided below.

Steam Assisted Gravity Drainage (SAGD)

[0035] SAGD may be carried out in geological formations wherein a water layer or gas cap lies above heavy oil containing strata. Good recovery of heavy oil may be achieved by injecting a thermally and/or chemically-activated blocking agent into the water or gas layer, preferably adjacent to the heavy oil/water or gas layer interface to reduce or prevent escape of extraction steam into the water- or gas-containing layer, and to reduce or prevent leakage of water into the heavy oil strata or steam chamber produced by the extraction steam.

[0036] FIG. 1 is a drawing of a SAGD process 100 used for accessing hydrocarbon resources in a reservoir 102. In the SAGD process 100, steam 104 can be injected through injection wells 106 to the reservoir 102. The injection wells 106 may be horizontally drilled through the reservoir 102. Production wells 108 may be drilled horizontally through the reservoir 102, with a production well 108 underlying each injection well 106. The injection wells 106 and production wells 108 may be drilled from the same pad 110 at the surface 112. Drilling from the same pad 110, may make it easier for the production well 108 to track the injection well 106. Alternatively, the injection well 106 and the production well 108 may be drilled from different pads 110. For example, the injection well 106 and the production well 108 may be drilled from different pads 110 if the production well 108 is an infill well.

[0037] The injection of steam 104 into the injection wells 106 may result in the mobilization of hydrocarbons 114. Once mobilized, the hydrocarbons 114 may drain to the production wells 108 and be removed to the surface 112 in a mixed stream 116 that may contain hydrocarbons, condensate and other materials, such as water, gases, and the like. Sand filters

may be used in the production wells **108** to decrease sand entrainment in the hydrocarbons removed to the surface **112**.

[0038] A mixed stream **116** from a number of production wells **108** may be combined and sent to a processing facility **118**. At the processing facility **118**, the water and hydrocarbons **120** can be separated, and the hydrocarbons **120** sent on for further refining. Water from the separation may be recycled to a steam generation unit within the facility **118**, with or without further treatment, and may be used to generate the steam **104** used for the SAGD process **100**.

[0039] The production wells **108** may have a segment that is relatively flat, which, in some developments, may have a slight upward slope from the heel **122**, at which the pipe branches to the surface, to the toe **124**, at which the pipe ends. When present, an upward slope of this horizontal segment may result in the toe **124** being around one to five meters higher than the heel **122**, depending on the length of the horizontal segment. The slight slope can assist in draining fluids that enter the horizontal segment to the heel **122** for removal.

[0040] It should be appreciated that, while one form of SAGD is described above, the present disclosure may relate to any and all forms of SAGD.

[0041] SAGD may be carried out in geological formations wherein a water containing layer (water zone) and/or a gas containing layer (gas cap) lies directly above and in contact with heavy oil containing strata, e.g. layer **102** of FIG. 1. Good recovery of heavy oil may be achieved by injecting a blocking agent into the water and/or gas containing layer to reduce or prevent escape of extraction steam into the water and/or gas containing layer, and/or to reduce or prevent leakage of water from the water and/or gas containing layer into the heavy oil strata or steam chamber produced by the extraction steam.

[0042] A variety of materials, both aqueous and non-aqueous, may be employed as blocking agents. The blocking agents may be employed singly or in combination, as will be described later. The blocking agents may undergo a transformation when in situ in a reservoir formation from a form in which the blocking agents may freely penetrate a permeable region of a rock, sand or soil substrate, to a form in which the blocking agents prevent or substantially limit the movement of fluids through the region that they have penetrated. When the blocking agents assume this form, they have become a seal limiting or preventing fluid flow through the affected substrate. The blocking agents may be chosen from thermally-activated and chemically-activated blocking agents. Some blocking agents may undergo activation by both thermal and chemical effects.

[0043] Thermally-activated blocking agents may be fluids, generally liquids. When ready for injection into water and/or gas containing layers, one type of thermally activated blocking agents may be at ambient temperatures (temperatures that are ambient at the surface, e.g. nominally 21° C.), or at initial ambient temperatures within the reservoir where they are to be injected (temperatures before the start of recovery processes, generally 6 to 15° C.). The thermally activated blocking agents of this type may undergo a transformation at higher temperatures, e.g. at temperatures between ambient and 175° C., for example, ambient up to 125° C. or ambient up to 100° C., after which the blocking agents exhibit higher viscosity, density or solidity (e.g. form a precipitate or become solid). The thermally activated blocking agents of this type may contain compounds that exhibit inverse solubility character-

istics. In other words, the thermally activated blocking agents may contain compounds that are less soluble in solvents at higher temperatures than at lower temperatures, so that solutions of these compounds may have low viscosity at low temperature but may form precipitates or gels or solids or glasses, etc., at higher temperatures. The thermally activated blocking agents of this type may rely on absorbing heat for activation when present in a reservoir. The thermally activated blocking agents may absorb heat from steam used for SAGD.

[0044] Other types of thermally-activated blocking agents may include those containing compounds having normal solubility characteristics, i.e. compounds that become more soluble in solvents as temperature increases, or conversely and more importantly, compounds that become less soluble in solvents as the temperature decreases. As a result, the compounds having normal solubility characteristics may precipitate out of solution as the temperature of the solution falls. The thermally-activated blocking agents of these types may be prepared or obtained as saturated or supersaturated solutions at high temperatures (e.g. 80° C. or higher) and are injected into the reservoir at such high temperatures. As the saturated or supersaturated solutions encounter and penetrate reservoir substrates having lower temperatures than the injected saturated or supersaturated solutions (i.e. initial reservoir ambient temperatures of e.g. 6 to 15° C.), the saturated or supersaturated solutions are activated by forming solid or semi-solid precipitates that act to block pores and interstices in the rock, sand or soil substrate. Therefore, in this way, the blocking agents are thermally-activated, but by cooling rather than by heating.

[0045] Chemically-activated blocking agents may be compounds or compositions that are fluids, e.g. liquids, of suitably low viscosity that they may freely penetrate a region of the rock, sand or soil of a reservoir formation, but that undergo a chemical transformation when in situ in the penetrated region upon encountering one or more chemicals present in, or generated within, or introduced into, the formation. The chemical transformation causes an increase of viscosity, density or solidity so that the chemically activated blocking agent then prevents or limits the movements of fluids through the region that the fluids occupy. For example, chemically-activated blocking agents may be reactive with gases or acids produced in a heavy-oil containing layer upon exposure of the heavy oil or the substrate to the temperatures employed during SAGD. For example, thermolysis of components of the heavy oil may produce carbon dioxide or hydrogen sulfide that may then contact and react with the chemically activated blocking agents to cause the indicated transformations.

[0046] When a single blocking agent is employed, the blocking agent may be a thermally-activated blocking agent that undergoes a transformation as it absorbs heat from steam used in a SAGD process. When at least one further blocking agent is employed (i.e. two or more blocking agents), a thermally-activated blocking agent (i.e., a first blocking agent) may first be injected into the water and/or gas containing layer so that the thermally-activated blocking agent occupies a region close to the interface between the water and/or gas containing layer and the heavy oil containing layer. The thermally-activated blocking agent is, therefore, close to the steam chamber created during SAGD and receives heat from the steam for the transformation required by the thermally-activated blocking agent to form a seal. After injecting the

first blocking agent, a second blocking agent may then be injected into the formation to occupy a second region above and/or surrounding the first region occupied by the first blocking agent. The second blocking agent may be one that does not require heat from the steam to undergo its required transformation. The second blocking agent may not necessarily have to be positioned as close to the steam chamber because it does not require heat. The second blocking agent may therefore be a thermally-activated blocking agent of the kind containing a compound having normal solubility characteristics that is injected hot and undergoes a transformation as it cools, or it may be a chemically-activated blocking agent that reacts with gases or fluids present in, or generated within, the formation. An advantage of using a second blocking agent of one of these kinds is that the second blocking agent may extend the area or thickness of the blocking seal beyond the zone penetrated by heat from the steam that is required for transformation of the first-injected blocking agent. Of course, a third or even more blocking agents may be injected into the formation to further extend the area or thickness of the blocking seal, but possibly at the expense of increased cost and/or diminishing effectiveness. If such a third or more blocking agent is employed, it may also be one that does not require heat from the steam to undergo transformation.

[0047] When a second blocking agent is employed, it may be injected into the water and/or gas containing layer at any time, e.g. during commencement of the SAGD process, during start-up of the SAGD process, or during operation of the SAGD process.

[0048] Examples of thermally-activated blocking agents of the type having inverse solubility characteristics include, but are not limited to, aqueous solutions of sodium silicate and aqueous solutions of calcium bicarbonate. When subjected to heating, sodium silicate forms a gel or glass-like solid that forms an effective seal. Calcium bicarbonate, in contrast, tends to deposit a solid precipitate that forms a seal. Colloidal silica may also be effective as it may form a gel at an elevated temperature.

[0049] As an example, solutions of sodium silicate may be injected into a water and/or gas containing layer to penetrate a region of the water and/or gas containing layer and may remain in liquid form for prolonged periods of time at normal ambient reservoir temperatures. However, when heated by heat from a steam chamber created during SAGD, the solutions, after a certain period of time (hours to days or even months), form a glass-like gel that significantly reduces the effective permeability of the rock, sand or soil so that fluids can no longer flow through the rock, sand or soil, thereby forming an effective barrier acting as a seal. The glass-like gel may have good stability at the temperatures encountered, with little tendency to degrade, so that the seal remains effective and in place for a suitably long time, even for the duration of the SAGD process and possibly for the full productive life of the SAGD wells, which may be from 10 to 30 years. Of course, if the seal is found to break down or leak over time during the SAGD process, further thermally-activated blocking agent may be introduced through the blocking agent injection well to supplement or repair the seal as required.

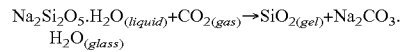
[0050] Sodium silicate is the common name for the compound sodium metasilicate, Na_2SiO_3 or $(\text{SiO}_2)_n \cdot \text{Na}_2\text{O}$, sometimes known as waterglass. It is available commercially as an alkaline aqueous solution (pH 11-13) having water-like viscosity, as well as in solid form that may be dissolved in water. Upon exposure to heat, the sodium silicate forms silica aggregates

or polymers creating a gel that reduces the permeability of porous rock, soil or sand. Chelating agents (e.g. ethylenediamine tetracetic acid (EDTA) or nitrilotriacetic acid (NTA)) and/or acids (e.g. 6.5 vol. % HCl) may be added to the sodium silicate solution to help the material set or solidify in the presence of heat. The gel formation may take from several minutes to several months depending on temperature conditions and additives. A liquid form of sodium silicate may be obtained, for example, from BIM Norway under the trademark Krystazil 40. This product has a $(\text{SiO}_2)_n \cdot \text{Na}_2\text{O}$ ratio of 3.4, a pH of 11.5 and a concentration of 27.6 wt %. Before use, it may be diluted with water (e.g. to about 4 wt. %) and provided with a pH activator (e.g. HCl added under agitation in an amount of wt. % of the 2.0 M HCl stock solution). Further information about suitable sodium silicate gel systems and their preparation may be obtained from the following publication, the disclosure of which is incorporated herein by reference:

[0051] Burns L., et al., “*New Generation Silicate Gel System for Casing Repairs and Water Shutoff*”, Society of Petroleum Engineers, SPE 113490, presented at 2008 SPE/DOE Improved Oil Recovery Symposium held in Tulsa, Okla., U.S.A., 19-23 Apr., 2008.

The Burns publication describes sodium silicate solutions containing partially hydrolyzed polyacrylamide used in combination with a silica polymer gel initiator and employing an organic initiator.

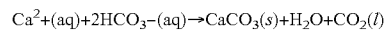
[0052] While sodium silicate is described above as a thermally-activated blocking agent of the kind having inverse solubility characteristics, it may also operate as a chemically-activated blocking agent. Sodium silicate may operate as a chemically-activated blocking agent because it may react with available carbon dioxide (produced, for example, by heavy oil thermolysis during SAGD) to form silica gel and a glass-like sodium carbonate, e.g. by the following reaction:



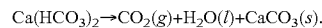
[0053] Colloidal silica, which is another example of a thermally-activated blocking agent of the kind having inverse solubility characteristics, forms a colloidal solution (sol) or gel when subjected to heat from steam used in the SAGD process. Further details of the preparation and characteristics of colloidal silica may be obtained from the following publication, the disclosure of which is incorporated herein by reference:

[0054] Jurinak J. J. et al., “*Oilfield Applications of Colloidal Silica Gel*”, Production Engineering, November 1991, pp. 406-412.

As noted above, calcium bicarbonate, which is another example of a thermally-activated blocking agent having inverse solubility characteristics, reacts with heat to deposit calcium carbonate according to the reaction below:



or



More information about calcium carbonate deposits may be obtained from the following publication, the disclosure of which is incorporated herein by reference:

[0055] John E. Oddo, et al., “*Simplified Calculation of CaCO_3 Saturation at High Temperatures and Pressures in*

Brine Solution", Journal of Petroleum Technology, Vol. 34, No. 7, pp. 1583-1590, July 1982.

[0056] An example of a material that may be suitable as a thermally- and/or chemically-activated blocking agent according to this disclosure is a solution of silica (SiO₂). Solutions of silica are typically removed from boiler feed water as a waste and are consequently inexpensive. Unlike sodium silicate or calcium bicarbonate, silica exhibits normal solubility characteristics in that its solubility increases or decreases with temperature increase or decrease, respectively. Soluble silica at high temperature precipitates out of solution when its temperature and/or pH is lowered. Soluble silica may be employed as a blocking agent by, for example:

[0057] a) Injecting water with a high silica concentration (e.g. a saturated or supersaturated solution) at high temperature (e.g. 80° C. or higher) into the reservoir so that, as the solution cools as it encounters ambient temperatures within the reservoir, SiO₂ precipitates from the solution, thereby forming a seal and blocking movement of steam or water into or from the water and/or gas containing layer. If steam does break through the resulting seal, acid gases (e.g. CO₂) formed by aqua-thermolysis within the heavy oil-bearing layer will be carried along with the steam. This escape of steam and acid gases may lower the pH of the injected silica solution and thereby initiate further precipitation of the silica. Silica solutions having a high silica concentration are useful as second (or later) blocking agents injected after a first blocking agent activated by heat from steam used for the SAGD process.

[0058] b) Injecting water with a high concentration of Ca, Mg or Fe as well as silica into the formation so that, as heat is encountered from the approaching steam chamber, insoluble Ca, Mg or Fe silicates or a combination thereof will form, again producing a seal and blocking the advancement of steam into the water and/or gas containing layer. Sodium-iron silicates may also be formed from sodium made available in the injected solution or present in the connate water. Silica solutions containing high concentrations of Ca, Mg or Fe may be used as a sole blocking agent (or the first of two or several) as they are activated by heat from the steam used for the SAGD process.

[0059] The amount or volume of the thermally- and/or chemically-activated blocking agent injected into the water and/or gas containing layer may be sufficient to form a penetrated region of effective extent to form a gas and/or water seal above the SAGD wells and the steam chamber created by the injection of steam. The required amount of the thermally- and/or chemically-activated blocking agent may vary from reservoir to reservoir and from formation to formation, and/or from well to well, due to differences of rock permeability, physical dimensions of the injection and production wells, details of the SAGD process, etc. An effective amount may be determined by simple trial and experiment, or may be calculated in advance by appropriate reckoning or algorithms. In general, the amount may be sufficient to form a seal that is at least as extensive as the top area of the steam chamber formed in the heavy oil containing layer when in its steady state of operation. Any steam rising in the chamber is then blocked by the seal and is forced to move horizontally into less heated structures. Suitable inflow/outflow control devices may be used for the injection of the thermally- and/or chemically-activated blocking agent to achieve even distribution of the

thermally- and/or chemically-activated blocking agent within the rock formation. In the case of SAGD wells that are 1000 meters long and provided with a lateral spacing of 100 meters between adjacent well pairs, drilled through substrate having pores forming 30% of the volume of the substrate, and aiming for a layer thickness of one meter, the total targeted pore space would be about 30,000 m³. Typically, only a fraction of this volume would need to be injected with the thermally and/or chemically-activated blocking agent in order to at least partially contact most of the pore space. For example, between 1,000 to 20,000 cubic meters of the thermally and/or chemically-activated blocking agent may be required in such a case.

[0060] Injection criteria for each specific reservoir may be established to prevent plugging or precipitation of the thermally- and/or chemically-activated blocking agent prior to in-situ heating by the steam used for the SAGD process. The use of pH modifiers, anti-scalants or similar chemical additives may be employed to achieve the objective of preventing plugging or precipitation. Water used for the preparation of the thermally- and/or chemically-activated blocking agent may be obtained from any available source, e.g. locally on-site.

[0061] While a thermally-activated blocking agent may be injected into the water and/or gas containing layer prior to operation of the SAGD process, or during SAGD start-up, as explained above, additional thermally-activated blocking agent may be injected into the water and/or gas containing layer during operation of the SAGD process. The additional thermally-activated blocking agent may be injected after the steam chamber has reached the top of the heavy oil containing layer to block areas that may potentially provide leaks of the steam into the water and/or gas containing layer. As the additional thermally-activated blocking agent is being injected, the pressure of steam used for the SAGD may be temporarily lowered to draw some of the further thermally-activated blocking agent into the heated zone where it will solidify and extend or repair the required seal. The steam thus confined to the steam chamber may thus give rise to good production rates and an efficient recovery process.

[0062] As also noted above, a second blocking agent may be injected into a second region of the water and/or gas containing layer before commencement of the SAGD process or during SAGD start-up. If so, further amounts of the second blocking agent may be injected into the water and/or gas containing layer during these stages, or later as the SAGD process proceeds, to further limit movements of fluids through the second region. Alternatively, a second blocking agent may be injected into the water and/or gas containing layer for the first time as SAGD proceeds, i.e. after commencement and startup of the SAGD, if supplementation of the seal formed by the first blocking agent appears to be necessary to improve or maintain heavy oil production. The second blocking agent may be injected into the water and/or gas containing layer (i) before commencement of the SAGD process and/or during SAGD start-up and (ii) as SAGD proceeds (i.e., after commencement and startup of the SAGD). Further addition(s) of the second blocking agent may then also be made as the SAGD process proceeds further in time.

[0063] FIGS. 2A through 2D show examples of steps in which a blocking agent is employed to create a seal between a hydrocarbon-containing layer 202 of an oil sands formation 200 and a water-containing and/or gas-containing layer 204 situated above the hydrocarbon-containing layer 202. As well as providing an injection well 206 and a production well 208

in the heavy oil-containing layer 202 as in conventional SAGD, at least one blocking agent injection well 210 is drilled into the water and/or gas containing layer 204. The at least one blocking agent may be drilled close to the interface 205 between layers 204 and 202. The blocking agent injection well 210 may be of similar length to the injection well 206 and the production well 208, or longer. The blocking agent injection well 210 may be positioned directly vertically above and parallel to such wells.

[0064] Prior to the operation of the SAGD process or before a steam chamber 216 produced by such process approaches the interface 205, a fluid thermally-activated blocking agent 212 may be injected into the water and/or gas containing layer 204. A region 214 may subsequently be formed containing the blocking agent in the pores or interstices of the rock, sand or soil of the layer 204 adjacent to or in contact with the interface 205 between the layers 202 and 204. While reference is made to region 214, it will be appreciated that the blocking agent will, in fact, occupy pores or interstices in the solid components of the layer and thus will not normally form an exclusively liquid body in the region. Although not shown, a further well or wells may be drilled into the water and/or gas containing layer 204 to remove water and/or gas as the blocking agent is being injected into the layer, thereby providing a uniform displacement of fluids. Such further well or wells may be positioned higher in the layer 204 than the blocking agent injection well 210 to avoid withdrawal of the blocking agent itself. The well(s) may be in the vicinity of injection well 210 to provide the necessary “venting” effect effective for fluid displacement. As noted, the region 214 containing the blocking agent introduced via injection well 210 may be created before the SAGD process is commenced, or at least before significant heat from the SAGD process permeates the water and/or gas containing layer 204. The blocking agent may be such that it remains fluid at the initial ambient temperatures normally found within such reservoirs, e.g. 6 to 15° C., for extended periods of time, e.g. several days, weeks or months.

[0065] The SAGD process is operated by injecting steam into the oil-containing layer 202 through the injection well 206 to heat the formation and to create a steam chamber 216 that expands in volume as the geological formation is gradually heated by the steam. The steam heats the heavy oil within the porous substrate and consequently the heavy oil becomes more fluid and descends within the formation so that it can be removed via the production well 208, e.g. by pumping. Pores partially drained of heavy oil in this way are occupied by further steam to expand the steam chamber 216. By heat conduction, the steam within the steam chamber also creates a heated zone 218 in the rock or soil formation above the steam chamber itself, and this eventually penetrates into the region 214 containing the blocking agent within the water and/or gas containing layer 204. The thermally-activated blocking agent within the region 214 is such that, when it is exposed to heat from the steam, it hardens, solidifies, precipitates solids, densifies, gels, or otherwise creates a fluid-blocking seal 220 above the heavy oil containing layer 202, thereby blocking pores within the rock, sand or soil formation. The seal restricts or prevents the flow of fluids. The seal serves to isolate, either partially or fully, the heavy oil containing layer 202 from the water and/or gas containing layer 204, at least in the region of the steam chamber 216 formed around the injection well 206. The seal may minimize or prevent the water and/or gas containing layer 204 from acting as a “thief

layer” that nullifies the effects of the steam and pressure used for the SAGD process. The seal may therefore enable improved recovery of heavy oil. The blocking seal 220 may help to prevent water from layer 204 descending into the steam chamber 216 and heated zone 218 and causing an undesired cooling effect.

[0066] It has been stated above that the blocking agent injection well 210 may be positioned close to the interface 205. However, sometimes the blocking agent may be injected close to the top of a water and/or gas containing layer, or at least significantly above the interface 205, and allowed to descend under gravity through the pores or interstices towards the interface. The blocking agent may be injected close to the top when layer 204 forms a gas cap. Gas is less likely to prevent the descent of the blocking agent than water. If there is a layer of high permeability within the gas cap, the injection of the thermally and/or chemically-activated blocking agent may target the high permeability layer. Targeting the high permeability layer may aid in ensuring that the blocking agent is well distributed above the SAGD wells 206, 208.

[0067] While one blocking agent injection well 210 may be provided for each steam injection well/production well pair 206, 208 (i.e. the SAGD wells), a single blocking agent injection well 210 may be provided for two or more such well pairs. The single blocking agent injection well 210 may be provided when the blocking agent injection well is suitably positioned (e.g. mid-way between and above two adjacent well pairs) and/or is of such a capacity for fluid delivery relative to the permeability of the substrate, to provide a blocking agent region 214 extending above such multiple pairs of SAGD wells. Moreover, while the blocking agent injection well 210 may be horizontal or close thereto as shown, the blocking agent injection well 210 may alternatively be vertical or more angularly sloped. The blocking agent injection well may be vertical or more angularly sloped if the resulting blocking agent region 214 forms above the heavy oil containing layer 202 in the region of the steam chambers formed by one or more pairs of SAGD wells to form an effective seal for all such SAGD wells.

[0068] The blocking agent 212 may be in the form of a liquid, e.g. a solution or emulsion, or in the form of a flowable slurry or gel, or in any other form that allows the blocking agent to be injected (e.g. allowed to flow under gravity or pumped) into the relevant layer to form an extensive region 214 containing the blocking agent which forms a seal when the blocking agent is transformed. The SAGD process is then capable of operating as it would in an equivalent reservoir having a relatively impermeable layer positioned above the heavy oil containing layer 202.

[0069] It will be understood that FIGS. 2A to 2D show an extremely simplified illustration of an underground reservoir in that the interface 205 may not be a distinct flat horizontal stratum as shown, but may vary in thickness (i.e. have varying heavy oil, water and/or gas content over its height) and may be of complex shape or arrangement. Moreover, the seal 220 formed at the interface may not be always form complete barrier to steam, gas and water, but may only increase the resistance to the penetration of such fluids through the seal. The seal may of course be such that the increase in such resistance produces a measurable increase in heavy oil recovery compared to the absence of such a seal in the same reservoir formation.

[0070] FIGS. 3A and 3B illustrate a procedure in which two blocking agents of different categories or types are injected

into a formation to form an effective seal. In the case of FIG. 3A, the arrangement is similar to that of FIG. 2A but an additional blocking agent injection well 310 has been drilled into the water and/or gas containing layer 204 above the original blocking agent injection well 210. A heat-activated blocking agent 212 of the kind having inverse solubility characteristics is injected through input well 210, as before, to produce a blocking agent-containing region 214. A second blocking agent 312 of a different kind, e.g. a chemically-activated blocking agent or a thermally-activated blocking agent of the type having normal solubility characteristics, is then injected into layer 204 through the additional blocking agent injection well 310. The second blocking agent 312 forms a region 314 overlying and extending horizontally beyond the margins of the region 214 containing the first-injected blocking agent 212. The first blocking agent may be activated by heat from a SAGD process in the manner shown in FIGS. 2C and 2D to form a seal. The second blocking agent 312 may be present to extend the seal in the regions where there is insufficient heat from the SAGD process to activate the blocking agent 212, or where reactive gases such as CO₂ escape from the heavy-oil containing layer 202 during the SAGD process.

[0071] In the case of FIG. 3B, as in FIG. 2A, there is only a single blocking agent injection wellbore 210 drilled into the water and/or gas containing layer 204. A first thermally-activated blocking agent 212 having inverse solubility characteristics may be injected into the layer through the wellbore 210. The first blocking agent 212 may be allowed to descend to the level of the interface 205 to form a first blocking agent containing region 214. A second blocking agent 312 of a different kind, e.g. a chemically-activated blocking agent or a thermally-activated blocking agent having normal solubility characteristics, may then be injected into the layer 204 through the same wellbore 210 to form a second blocking agent containing region 315 overlying and surrounding the region 214, just as in the case of FIG. 3A. The arrangement of FIG. 3B avoids the extra cost of drilling the additional wellbore 310 of FIG. 3A and is advantageous if the rock, sand or soil substrate of layer 204 is sufficiently porous to allow rapid and uniform percolation of the first-injected blocking agent 212 through the layer towards the interface 205. It may also be advantageous to drill the injection wellbore 210 slightly higher in the layer 204 in the case of FIG. 3B to allow room above the interface 205 and below the wellbore 210 to accommodate the entire region 214.

[0072] While detailed information has been provided above, it will 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 in any effective manner.

[0073] 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.

What is claimed is:

1. A method of recovering heavy oil from a hydrocarbon reservoir in which a water and/or gas containing layer overlies a heavy oil containing layer, the method comprising:

providing an injection well in said water and/or gas containing layer above at least one pair of horizontal wells in said heavy oil containing layer for heavy oil recovery by a steam assisted gravity drainage process;

injecting a first blocking agent into said water and/or gas containing layer via said injection well to form a first region of said water and/or gas containing layer containing said first blocking agent adjacent an interface between said water and/or gas containing layer and said heavy oil containing layer above said at least one pair of horizontal wells; and

operating said steam assisted gravity drainage process via said at least one pair of horizontal wells by injecting steam into said heavy oil containing layer and recovering heavy oil from said heavy oil containing layer;

wherein said first blocking agent is injected into said water and/or gas containing layer before operating said steam assisted gravity drainage process or before heat generated by said steam assisted gravity drainage process reaches said first region of said water and/or gas containing layer; and

wherein said first blocking agent, when present in said first region, undergoes a change of viscosity, density or solidity when elevated to a temperature between an initial ambient reservoir temperature in said first region and 175° C. by heat from steam used in said steam assisted gravity drainage process, and thereby creates a seal within the hydrocarbon reservoir above said at least one pair of horizontal wells limiting or preventing movements of fluid through said seal.

2. The method of claim 1, wherein said first blocking agent is in a form selected from the group consisting of a liquid, a flowable slurry, and a gel.

3. The method of claim 1, wherein said first blocking agent is in a form of a liquid selected from the group consisting of a solution and an emulsion.

4. The method of claim 1, wherein said first blocking agent has inverse-solubility characteristics such that the first blocking agent is configured to increase in viscosity, density or solidity with increase of temperature.

5. The method of claim 1, wherein said first blocking agent increases in viscosity, density or solidity to form said seal within the reservoir when heated by heat from said steam to a temperature between initial ambient temperature of said first region and about 125° C.

6. The method of claim 1, wherein said first blocking agent increases in viscosity, density or solidity to form said seal within the reservoir when heated by heat from said steam to a temperature between initial ambient temperature of said first region and about 100° C.

7. The method of claim 1, wherein said first blocking agent comprises an aqueous solution of sodium silicate.

8. The method of claim 7, further comprising introducing an additive into said aqueous solution, said additive being at least one compound selected from the group consisting of acids, chelating agents, pH modifiers and anti-scalants.

9. The method of claim 7, wherein said sodium silicate is present in said aqueous solution at a concentration in a range of 1 to 10 wt. %.

10. The method of claim 7, wherein said sodium silicate is present in said aqueous solution at a concentration in a range of 3 to 5 wt. %.

11. The method of claim 1, wherein said first blocking agent comprises an aqueous solution of sodium bicarbonate.

12. The method of claim **1**, wherein said first blocking agent comprises colloidal silica.

13. The method of claim **1**, wherein said first blocking agent comprises a solution of silica and a soluble compound of a metal selected from the group consisting of Ca, Mg and Fe that forms insoluble metal silicates when subjected to heat from said steam.

14. The method of claim **1**, wherein, after injecting said first blocking agent into said water and/or gas containing layer, a second blocking agent is injected into said water and/or gas containing layer to form a second region above said at least one pair of horizontal wells, said second blocking agent undergoing an increase of density, viscosity or solidity when situated within said second region.

15. The method of claim **14**, wherein said second blocking agent is injected into said water and/or gas-containing layer via said injection well used for injection of said first blocking agent.

16. The method of claim **14**, wherein said second blocking agent is injected into said water and/or gas-containing layer via at least one injection well different from said injection well used for injection of said first blocking agent first.

17. The method of claim **14**, wherein said second blocking agent is a thermally-activated blocking agent having normal solubility characteristics such that said second blocking agent is configured to increase in viscosity, density or solidity with decrease of temperature when injected at elevated temperature into said water and/or gas containing layer.

18. The method of claim **14**, wherein said second blocking agent comprises an aqueous solution of silica injected into said water and/or gas containing layer at an elevated temperature above said ambient reservoir temperature.

19. The method of claim **18**, wherein said elevated temperature is a temperature of at least 80° C.

20. The method of claim **1**, wherein said steam assisted gravity drainage process comprises:

injecting steam into said heavy oil containing layer via an uppermost one of said at least one pair of horizontal wells to heat heavy oil in said heavy oil containing layer to reduce viscosity of said heavy oil; and

removing the heavy oil from said heavy oil containing layer via a lowermost one of said at least one pair of horizontal wells.

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