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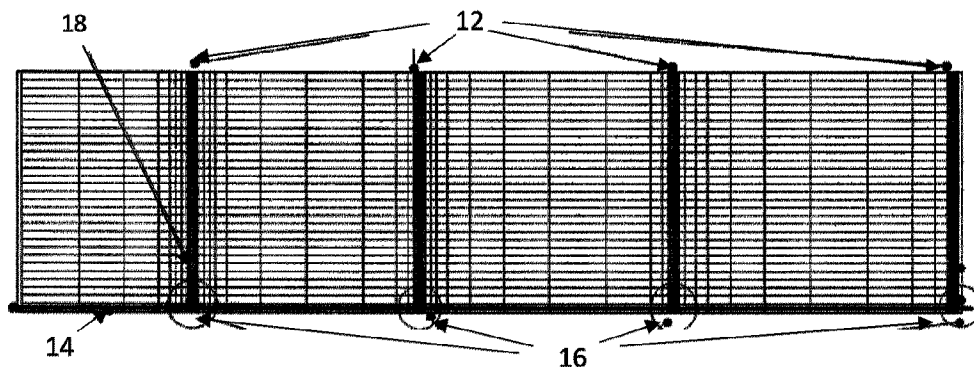
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(54) Title: VERTICAL STAGING WITH HORIZONTAL PRODUCTION IN HEAVY OIL EXTRACTION



(57) Abrégé/Abstract:

Processes are disclosed for staging the recovery of hydrocarbons from heavy oil reservoirs, involving the re-configuration of vertical injection wells to cooperate differently over time with horizontal production wells. Processes of this kind may involve thermal or non-thermal techniques, with the injection of aqueous or organic injection fluids being used to mobilize heavy oil in situ, with particular adaptations of the processes provided for use in stratigraphically heterogeneous reservoirs.

ABSTRACT

Processes are disclosed for staging the recovery of hydrocarbons from heavy oil reservoirs, involving the re-configuration of vertical injection wells to cooperate differently over time with horizontal production wells. Processes of this kind may involve thermal or non-thermal techniques, with the injection of aqueous or organic injection fluids being used to mobilize heavy oil in situ, with particular adaptations of the processes provided for use in stratigraphically heterogeneous reservoirs.

VERTICAL STAGING WITH HORIZONTAL PRODUCTION IN HEAVY OIL EXTRACTION

FIELD OF THE INVENTION

[0001] The invention is in the field of hydrocarbon reservoir engineering, particularly the arrangement and operation of wells in heavy oil reservoirs.

BACKGROUND OF THE INVENTION

[0002] Some subterranean deposits of viscous hydrocarbons can be extracted in situ by lowering the viscosity of the petroleum in a formation to mobilize it so that it can be moved to, and recovered from, a production well. Reservoirs of such deposits may be referred to as reservoirs of heavy hydrocarbon, heavy oil, bitumen, oil sands, or (formerly) tar sands. The in situ processes for recovering oil from oil sands typically involve the use of multiple wells drilled into the reservoir, and are assisted or aided by injecting a fluid such as steam, and/or a solvent, into the reservoir through an injection well to mobilize the viscous hydrocarbons for recovery through a production well.

[0003] A widely used thermal recovery process is steam-assisted gravity drainage (SAGD) as for example disclosed in Canadian Patent No. 1,130,201 issued on 24 August 1982, in which two wells are drilled into the deposit, one for injection of steam and one for production of oil and water. Steam is injected via the injection well to heat the formation. The steam condenses and gives up its latent heat to the formation, heating a layer of viscous hydrocarbons. The viscous hydrocarbons are thereby mobilized, and drain by gravity toward the production well with an aqueous condensate. In this way, the injected steam initially mobilizes the in-place hydrocarbon to create a "steam chamber" in the reservoir around and above the horizontal injection well. The term "steam chamber" accordingly refers to the volume of the reservoir which is saturated with injected steam and from which mobilized oil has at least partially drained. Mobilized viscous hydrocarbons are recovered continuously through the production well. The conditions of steam injection and of hydrocarbon production may be modulated to control the growth of the steam chamber, to ensure that the production well remains located at the bottom of the steam chamber in an appropriate position to collect mobilized hydrocarbons.

[0004] The start-up stage of a heavy oil recovery process often involves establishing thermal or hydraulic communication, or both, between injection and production wells. At initial reservoir conditions, there is typically negligible fluid mobility between wells due to high bitumen viscosity. Communication is achieved when bitumen between the injector and producer is mobilized to allow for bitumen production. A conventional start-up process involves establishing interwell communication by simultaneously circulating steam through each injector well and producer well. High-temperature steam flows through a tubing string that extends to the toe of each horizontal well. The steam condenses in the well, releasing heat and resulting in a liquid water phase which flows back up the casing-tubing annulus. Alternative start-up techniques involve creating a high mobility inter-well path by the use of solvents, as for example described in Canadian Patent No. 2,698,898, or by application of pressures so as to dilate the reservoir sand matrix, as for example described in Canadian Patent No. 2,757,125.

[0005] In the ramp-up stage of a heavy oil recovery process, after communication has been established between the injection and production wells during start-up (usually over a limited section of the well pair length), production begins from the production well. Typically, a mobilizing fluid such as steam or solvent is continuously injected into an injection well while mobilized bitumen and water are continuously removed from the production well. During this period the zone of communication between the wells may expand axially along the full well pair length, and a chamber depleted of hydrocarbons grows vertically towards the top of the reservoir. The reservoir top may be a thick shale (overburden) or some lower permeability facies that causes the steam chamber to stop rising. In some processes, for example SAGD, when the interwell region over the entire length of the well pair has been heated and the steam chamber that develops has reached the reservoir top, the bitumen production rate typically peaks and begins to decline while the steam injection rate reaches a maximum and levels off.

[0006] A wide variety of alternative enhanced or in situ recovery processes may be used that employ thermal and non-thermal components to mobilize oil. A wide variety of processes have been described that use hydrocarbon solvents in addition to steam, or

in place of steam, in processes analogous to conventional SAGD, or in processes that are alternatives to SAGD. For example, Canadian Patent Number 2,299,790 describes methods for stimulating heavy oil production using a propane vapor. Similarly, Canadian Patent No. 2,323,029 describes an in situ recovery process involving injection of steam and a non-aqueous solvent. Unheated hydrocarbon vapours have been proposed for use to dissolve and displace heavy oils in a process known as VAPEX (Butler and Mokrys, J. Can. Petro. Tech. 1991,30; U.S. Pat. No. 5,407,009). Processes for cyclic steam stimulation of vertical wells using hydrocarbon solvents have been described (Leaute and Carey, J. Can. Petro. Tech., Vol. 46, No. 9, pp. 22-30, 2007). Field trials have also been reported for solvent assisted processes that involve the use of solvent, such as butane, as an addition or aid to injected steam in improving the performance of conventional SAGD (Gupta et al., Paper 2001-126, Can. Intl. Pet. Conf., Calgary, Alberta, June 12-14, 2001; Gupta et al., Paper No. 2002-299, Can. Intl. Pet. Conf., Calgary, Alberta, June 11-13, 2002; Gupta and Gittins, Paper No. 2005-190, Can. Intl. Pet. Conf., Calgary, Alberta, June 7-9, 2005). Similarly, solvent assisted processes characterized as Liquid Assisted Steam Enhanced Recovery (LASER) have been described, in which solvents are used in conjunction with steam to enhance performance of Cyclic Steam Stimulation (CSS).

[0007] Non-condensing gases (NCGs) may be present in heavy oil recovery process for a variety of reasons. In the context of alternative processes, NCGs have been described as offering both benefits and challenges to the optimal performance of recovery processes, such as SAGD systems. For example, US Patent No. 8,596,357 describes methods for adding a buoyancy-modifying agent to injected steam, such as an additional NCG, to help cause NCGs to accumulate at the top of the steam chamber. This approach reflects the fact that NCGs tend to be light and therefore buoyant, so that any NCG that is liberated or generated lower in the steam chamber will tend to rise to a higher part of the steam chamber, and any NCG produced or released higher in the steam chamber will tend to remain in the upper elevations of the steam chamber. Other aspects of fluid dynamics in the SAGD process influence this vertical NCG flow.

[0008] In the context of the present application, various terms are used in accordance with what is understood to be the ordinary meaning of those terms. For example, “petroleum” is a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase, which includes various oxygen-, nitrogen- and sulfur- containing compounds and typically trace amounts of metal-containing compounds. In the context of the present application, the words “petroleum” “oil” and “hydrocarbon” are generally used interchangeably to refer to mixtures of widely varying composition, as will be evident from the context in which the word is used. The production of petroleum from a reservoir necessarily involves the production of hydrocarbons, but is not limited to hydrocarbon production. Similarly, processes that produce hydrocarbons from a well will generally also produce petroleum fluids that are not hydrocarbons. In accordance with this usage, a process for producing petroleum or hydrocarbons is not necessarily a process that produces exclusively petroleum or hydrocarbons, respectively.

[0009] “Fluids”, such as petroleum fluids, include both liquids and gases. Natural gas is the portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural gas may include amounts of non-hydrocarbons. The abbreviation POIP stands for “produced oil in place” and in the context of the methods disclosed herein is generally defined as the exploitable or producible oil structurally located above the production well elevation.

[0010] It is common practice to segregate petroleum substances of high viscosity and density into two categories, “heavy oil” and “bitumen”. For example, some sources define “heavy oil” as a petroleum that has a mass density of greater than about 900 kg/m³. Bitumen is sometimes described as that portion of petroleum that exists in the semi-solid or solid phase in natural deposits, with a mass density greater than about 1000 kg/m³ and a viscosity greater than 10,000 centipoise (cP; or 10 Pa.s) measured at original temperature in the deposit and atmospheric pressure, on a gas-free basis. Although these terms are in common use, references to heavy oil and bitumen represent categories of convenience, and there is a continuum of properties between

heavy oil and bitumen. Accordingly, references to heavy oil and/or bitumen herein include the continuum of such substances, and do not imply the existence of some fixed and universally recognized boundary between the two substances. In particular, the term "heavy oil" includes within its scope all "bitumen" including hydrocarbons that are present in semi-solid or solid form.

[0011] A reservoir is a subsurface formation containing one or more natural accumulations of moveable petroleum, which are generally confined by relatively impermeable rock. An "oil sand" or (formerly) "tar sand" reservoir is generally comprised of strata of sand or sandstone containing viscous petroleum, such as bitumen. Viscous petroleum, or such as bitumen, may also be found in reservoirs whose solid structure consists of carbonate material rather than sand material. Such reservoirs are sometimes referred to as bituminous carbonates. A "zone" in a reservoir is merely an arbitrarily defined volume of the reservoir, typically characterised by some distinctive property. Zones may exist in a reservoir within or across strata or facies, and may extend into adjoining strata or facies. In some cases, reservoirs containing zones having a preponderance of heavy oil are associated with zones containing a preponderance of natural gas. This "associated gas" is gas that is in pressure communication with the heavy oil within the reservoir, either directly or indirectly, for example through a connecting water zone.

[0012] A "chamber" within a reservoir or formation is a region that is in fluid communication with a particular well or wells, such as an injection or production well. For example, in a SAGD process, a steam chamber is the region of the reservoir in fluid communication with a steam injection well, which is also the region that is subject to depletion, primarily by gravity drainage, into a production well. A very wide variety of thermal and non-thermal recovery techniques may be used to deplete zones within a reservoir to create hydrocarbon or heavy oil depleted chambers within a reservoir.

SUMMARY OF THE INVENTION

[0013] Aspects of the invention involve hydrocarbon recovery from heavy oil reservoirs that take advantage of a particular geometry of injection and production wells.

In select embodiments, a hydrocarbon recovery zone bearing a heavy oil may be characterized as having a longitudinal axis formed by:

- i) a horizontal production well (analogous in some embodiments to a SAGD production well); and,
- ii) a plurality of vertical injection wells that are horizontally offset along the longitudinal axis of the recovery zone, each injection well terminating at an injection well bottom that is juxtaposed to and vertically spaced apart above the horizontal segment of the production well.

In this arrangement, the production well is characterized by having one or more horizontal segments, or dimensions, that extend along the longitudinal axis of the recovery zone. In addition to those horizontal segments or dimensions, production wells may have a very wide variety of trajectories, for example with vertical or lateral deviations. Similarly, the vertical injection wells are characterized as having a vertical component of well trajectory, and this may be within the context of a wide variety of radial or horizontal deviations. The plurality of injection wells may for example be characterized as having generally parallel vertical segments, with this conceptual generality of well alignment permitting a very wide range of deviations from geometrically true parallel alignment.

[0014] In one aspect of the invention, an arrangement of vertical injection wells along the longitudinal axis of a horizontal production well permits the initiation of contemporaneous mobilization and production of heavy oil. This may be accomplished by injecting an injection fluid, such as steam, water and/or solvent, through the injection wells to injection points proximal to the injection well bottoms, which are situated just above the horizontal producer. The injection fluid then mobilizes heavy oil in the vicinity of the production well, with mobilized heavy oil flowing by a gravity dominated process to the production well. In this way, an expanding recovery zone forms a chamber depleted of hydrocarbons, such as a steam chamber, which may be formed between each injection well bottom and the production well.

[0015] Once hydrocarbon production is initiated, the injection points of one or more injection wells may be vertically re-arranged, so that in a selected injection well the

injection point moves upwardly away from the horizontal segment of the production well, within the expanding chamber depleted of hydrocarbons. Injection and production of fluids may be continued, recovering mobilized heavy oil from the reservoir through the production well while injecting the injection fluid through the injection points, so that the expanding chambers depleted of hydrocarbons associated with a plurality of injection wells coalesce to form one or more common chambers.

[0016] In select embodiments, the reservoir may include a plurality of vertically spaced apart stratified recovery zones, the stratified recovery zones each being separated by one or more heterogeneous barriers, designated herein as barrier strata, in the formation. The barrier strata may for example be defined as having reduced permeability compared to adjacent recovery zones. These low permeability zones may for example include mud drapes, clasts, sandy inclined heterolithic stratification (IHS), muddy IHS, mudstone and/or shales. In formations of this kind, the step of vertically re-arranging the injection points of one or more injection wells may involve moving the injection point in an injection well from below a barrier strata to above a barrier strata. The plurality of vertically spaced apart stratified recovery zones may for example include recovery zones in two or more geological formations, such as zones within the Wabiskaw and McMurray formations. Alternatively, the recovery zones may be present within a single heterogeneous geological formation. In some embodiments, one or more injection arms may be drilled on an existing vertical well, and the injection point in that injection well may be moved from below a barrier strata to a position in the new injection arm above the barrier strata. In this way, an arm or sidetrack from an existing vertical well may be used to circumvent a barrier strata. To facilitate the identification of barrier strata, and provide a variety of data that may be used to optimize recovery processes, aspects of the process may involve data logging one or more of the injection wells to obtain stratigraphic information about the formation. This may for example take place before, during or after recovery processes.

[0017] Horizontal segments of a production well may for example be drilled by ranging from one vertical well to the next along the longitudinal axis of the recovery

zone. Alternatively, one or more of the vertical wells may be drilled by ranging to the horizontal segment of the production well along the longitudinal axis.

[0018] In alternative aspects of the process, fluids may be produced through one or more of the injection wells, for example using the injection wells as vent wells to vent non-condensing gases from collection points within an upper portion of the recovery zone.

BRIEF DESCRIPTION OF THE DRAWINGS

[0019] **Figure 1** is a schematic illustration of a well pattern in longitudinal cross section, showing four vertical injector wells paired with a horizontal (denoted “Hz”) producer well within the hydrocarbon rich pay zone of the formation.

[0020] **Figure 2** is a schematic cross sectional view of an elevated injection point in a vertical injection well.

[0021] **Figure 3** is a schematic illustration of a simulated 3D model of a stratified heavy oil reservoir, showing areas of differing permeability and fluid saturation as is typical of various oil sand reservoirs, such as the Grand Rapids, Clearwater, Wabiskaw and McMurray formations in Alberta, Canada. Porosity is indicated as shown on the scale provided.

[0022] **Figure 4** is a schematic illustration of a localized redirection in a vertical well, to circumvent a barrier zone in a stratified formation.

[0023] **Figure 5** is a ternary cross section through the longitudinal axis of a typical SAGD well pair, 100 days into a simulated circulatory start-up process, illustrating the temperature profile within the reservoir.

[0024] **Figure 6** is a ternary cross section through the longitudinal axis of a typical SAGD well pair, as illustrated in Figure 5, 50 days into a simulated SAGD process, illustrating the growing steam chamber in temperature profile within the reservoir.

[0025] **Figure 7** is a series of three cross sections through the longitudinal axis of a reservoir undergoing production using four vertical injector wells working in concert with a horizontal production well, showing successive stages of steam chamber development in temperature profile, at 20, 100, and 250 days following initiation of recovery operations.

[0026] **Figure 8** shows two cross sections through the longitudinal axis of reservoirs, illustrating oil saturation after 508 days in reservoirs undergoing alternative production operations, with the top section showing oil saturation in a reservoir undergoing recovery using four vertical injector wells working in concert with a horizontal production well, and the bottom section showing oil saturation using a typical SAGD recovery operation.

[0027] **Figure 9** illustrates the temperature profile in a cross section through the longitudinal axis of a heterogeneous reservoir undergoing production using four vertical injector wells working in concert with a horizontal production well, illustrating the effects of moving a steam injection point above an impermeable shale zone in one of the vertical wells (second from left).

[0028] **Figure 10** shows two cross sections through the longitudinal axis of reservoirs, illustrating oil saturation after 508 days in heterogeneous reservoirs having an impermeable shale zone undergoing alternative production operations, with the top section showing oil saturation in a reservoir undergoing recovery using four vertical injector wells working in concert with a horizontal production well, and the bottom section showing oil saturation using a typical SAGD recovery operation, with the shale zone in the region of the second from left vertical well as illustrated in Figure 9.

[0029] **Figure 11** is a graph illustrating cumulative oil production (COP) in alternative production scenarios, with curves from top to bottom in the legend showing COP for: SAGD production in a homogeneous reservoir; vertical injectors with horizontal

production (VIHP) in a homogeneous reservoir; SAGD production in a heterogeneous reservoir; and VIHP in a heterogeneous reservoir.

[0030] **Figure 12** is a graph illustrating cumulative steam injection (CSI) in alternative production scenarios, with curves in the legend showing CSI for: SAGD steam injection in a heterogeneous reservoir; vertical injectors with horizontal production (VIHP) in a homogeneous reservoir (broken line overlapping CSI for vertical injectors with horizontal production (VIHP) in a heterogeneous reservoir); and SAGD steam injection in a homogeneous reservoir.

[0031] **Figure 13** is a graph illustrating cumulative steam to oil ratio (CSOR) in alternative production scenarios in a heterogeneous reservoir (results for the homogeneous reservoir were essentially the same).

DETAILED DESCRIPTION OF THE INVENTION

[0032] Aspects of the invention involve staging of hydrocarbon recovery from heavy oil reservoirs, re-configuring vertical injection wells to cooperate differently over time with a horizontal production well. For example, in an initial start-up stage of production, the vertical injection wells may be operated with fluid injection points in close proximity to the horizontal producer, and this has been found to accelerate oil production, with mobilization and production of oil being generally contemporaneous. In this way, lengthy and energetically expensive start-up processes, for example circulation, may be avoided.

[0033] Once hydrocarbon production is initiated, the injection points of one or more injection wells may be re-arranged. This may be particularly advantageous in heterogeneous reservoirs, as for example illustrated in **Figure 3** (and described in Hein et al., Earth Sciences Report 2000-07, An Atlas of Lithofacies of the McMurray Formation, Athabasca Oil Sands Deposit, Northeastern Alberta: Surface and Subsurface). In reservoirs of this kind, recovery zones may be stratified, each being separated by one or more heterogeneous barrier strata in the formation. In this

circumstance, vertical wells that are to be used in recovery processes as injection wells may also be used as stratigraphic wells, with data logging in one or more of the vertical wells providing stratigraphic information about the formation, before, during or after recovery processes (as for example described in Tittman, Geophysical Well Logging: Excerpted From Methods of Experimental Physics, Elsevier, Dec 2, 2012). Additional stratigraphic wells may also of course be used to provide this kind of information about a particular formation. As schematically illustrated in **Figure 4**, stratigraphic information of this kind may be used to determine optimal localized redirection of the vertical wells based on geology, for example to circumvent an impermeable strata, as illustrated. Alternatively, this stratigraphic information may be used to determine optimal positioning of steam injection points, for example facilitating the movement of the injection point in an injection well from below a barrier strata to above a barrier strata.

[0034] In alternative aspects of the invention, a wide variety of drilling techniques may be used, including directional drilling techniques (as for example described in Chin et al., Measurement While Drilling (MWD) Signal Analysis, Optimization and Design, John Wiley & Sons, Apr 16, 2014). For example, horizontal segments of a production well may for example be drilled by ranging from one vertical well to the next along the longitudinal axis of the recovery zone. Alternatively, one or more of the vertical wells may be drilled by ranging to the horizontal segment of the production well along the longitudinal axis. In a further alternative aspect of the invention, one or more vertical wells may be paired with an existing horizontal well, for example, a multilateral well, an infill well, or a well drilled using Wedge Well™ technology (as for example described in Canadian Patent No. 2,591,498). This may be advantageous in retrofitting existing wells or facilities associated with heterogeneous reservoirs.

[0035] A wide variety of well completions may be used in alternative aspects of the processes described herein (as for example described in Renpu, Advanced Well Completion Engineering, Gulf Professional Publishing, Aug 23, 2011; or, in Speight, J., Heavy Oil Production Processes, Gulf Professional Publishing, Mar 5, 2013). For example, in alternative aspects of the process, fluids may be produced through one or more of the injection wells, for example using the injection wells as vent wells to vent

non-condensing gases from collection points within a selected zone, such as an upper portion of the recovery zone.

[0036] In select embodiments, the barrier may separate recovery zones in different geological formations or within a single formation, and the step of vertically re-arranging the injection points of one or more injection wells may involve moving the injection point in an injection well from below the barrier to above the barrier. Fluids may be produced through one or more of the injection wells, for example using the injection wells to drain the fluids for recovery through a production well.

[0037] Various aspects of the invention may involve the use of a wide variety of injection fluids, for example being heated or not heated. Water, steam and/or nonaqueous or organic solvents or diluents may for example be used. Non-aqueous injection fluids may for example include straight or branched chain, cyclic or aromatic hydrocarbons, such as a C3 to C10 linear or cyclic alkane, particularly n-alkanes or mixtures thereof, alkenes, or alkynes, in substituted or unsubstituted form, or other aliphatic or aromatic compounds. Substituents may for example include organic substituents or heteroatoms such as halogens. Injection fluids may also include a variety of additives, such as: a surface active agent (capable of modifying the interfacial tension of liquids), an emulsifier, a foaming or defoaming agent, a polymer, solid particulate matter or a microbial agent (such as one or more bacterial or viral cultures, which is capable of modifying the resident reservoir fluids so that mobility of the resident hydrocarbons is increased).

Example: Vertical Injection Staging with Horizontal Production

[0038] In accordance with various aspects of the invention, detailed computational simulations of reservoir behaviour have been carried out. **Figure 1** illustrates aspects of this computation model, showing a modeled well pattern in longitudinal cross section, showing 4 vertical injector wells **12** paired with a horizontal producer well **14** within the hydrocarbon rich pay zone of the formation, and further illustrating a first configuration **16** with injecting close to the Hz producer and a second configuration **18** with injection from higher points in the vertical direction. Aspects of the model involve vertically repositioning fluid injection points, as schematically illustrated in **Figure 2** where an embodiment is illustrated in which steam injection **20** is occurring 5 meters above the producer, particularly in the context of heterogeneous reservoir environments, as illustrated in **Figure 3**. These

detailed simulations have demonstrated the ability to expedite the initiation of oil production and adapt recovery techniques to improve production in heterogeneous reservoirs, using a process involving vertical injection with horizontal production (VIHP).

Simulation Models: SAGD and VIHP

[0039] SAGD:

Reservoir Components: fluid water, bitumen, methane, sand non-permeable shale.

Reservoir: X,Y,Z -50 m, 800 m, 30 m; Initially, reservoir at $T=12^{\circ}\text{C}$, $P=3\text{ MPa}$, $S_w=20\%$ (water saturation), $S_o=80\%$ (oil saturation), methane within oleic phase is 16%; Permeabilities (in darcys): X,Y,Z: 6 d, 6 d, 5 d and porosity at 33%. $S_w=60\%$, $S_o=40\%$. Overburden and underburden are coupled vertically to the reservoir.

Completions: Injector casing length 800 m with outer diameter at $177.8\text{e}^{-3}\text{ m}$ and inner diameter at $159.4\text{e}^{-3}\text{ m}$. Injector tubing with outer diameter at $134.3\text{e}^{-3}\text{ m}$ and inner diameter at $100.5\text{e}^{-3}\text{ m}$. Production casing length 800 m with outer diameter at $177.8\text{e}^{-3}\text{ m}$ and inner diameter at $159.4\text{e}^{-3}\text{ m}$. Both injector and producer casing fully perforated with injector skin at 2 and c_factor at 0.75 and producer skin at 50 and c_factor at 0.75 to account for suitable fluid transmissibility.

[0040] VIHP:

Reservoir Components: fluid water, bitumen, methane, sand, non-permeable shale.

Reservoir: X,Y,Z -50 m, 800 m, 30 m; Initially, reservoir at $T=12^{\circ}\text{C}$, $P=3\text{ MPa}$, $S_w=20\%$, $S_o=80\%$, methane within oleic phase is 16%; Permeabilities: X, Y, Z: 6, 6, 5 d and porosity at 33%. $S_w=60\%$, $S_o=40\%$. Overburden and underburden are coupled vertically to the reservoir.

Completions: Production casing length 800 m with outer diameter at $177.8\text{e}^{-3}\text{ m}$ and inner diameter at $159.4\text{e}^{-3}\text{ m}$. The producer casing fully perforated with injector skin at 2 and c_factor at 0.75 and producer skin at 50 and c_factor at 0.75 to account for suitable fluid transmissibility.

[0041] The fluid injection pattern during the start-up phase was different for SAGD and VIHP. In VIHP, start-up was carried out by injecting 100 tonnes/day (t/d) of steam about 1 m above the horizontal producer for 50 days. In SAGD, start-up was carried out by injecting and circulating about 5000 tonnes of steam (half symmetry model) in the injection and production wells (as illustrated in **Figure 5**). A person of skill in the art will understand that SAGD start-up circulation rates may be higher (as for example described in Yuan, J.-Y. & McFarlane, R., *Journal of Canadian Petroleum Technology*, January 1, 2011, pp. 20-32, Society of Petroleum Engineers).

[0042] Steam injection in the operational phase of both the SAGD and VIHP operations was equilibrated, in the sense that the SAGD steam injection rates were also used to inject steam via the re-positioned (elevated) vertical injectors. In effect, the steam injected in the SAGD operation, which passed through 4 multi-splitter flow control devices (FCDs), was introduced via the 4 vertical wells. In the operational phase of SAGD, steam is injected at the heel of the injector tubing and controlled on 3.1 MPa injection. Trickle sources with insignificant stimulation rate were introduced to enhance flow via the steam splitters (subs), and these were shut in after 20 days. The four multi-splitters were placed at 20e^{-3} m, 28e^{-3} m, 40e^{-3} m, and 56.57e^{-3} m, introduced in sections 3, 7, 11, and 15 of the injector tubing respectively, with discharge coefficients at 0.7, 0.73, 0.81, and 0.95 respectively. The producer was controlled on gas production of $10\text{ m}^3/\text{day}$ to allow fluid buildup around the producer with a sub-cool of at least 10°C . The production constraint did not change during all simulations. The temperature profile of the SAGD steam chamber after 550 days is shown in **Figure 6**.

[0043] **Figure 7** illustrates the modeled VIHP steam chamber development, with the steam injection points initially 1 m above the horizontal producer for 50 days, and then re-positioned upwardly to injection points 5 m above the horizontal segment of the producer (also illustrated in **Figure 1**). As illustrated, VIHP initially developed localized steam chambers, and at this stage the production well was producing condensed water with bitumen essentially contemporaneously with start-up of injection. As modeled, the producer was able to produce a bitumen-water emulsion 10 days after initiating steam

injection through the vertical wells, with the producer constraint at steam production of 10 t/d.

[0044] **Figure 8** provides a comparison of the oil saturation profiles achieved by SAGD and VIHP operations at 508 days. As illustrated, VIHP (top frame of **Figure 8**) recovers oil more rapidly at the upper sections of the reservoir than SAGD (bottom frame of **Figure 8**).

[0045] To model a heterogeneous reservoir, a non-permeable block was introduced as a variation on the homogeneous simulation set-up, both for the SAGD and the VIHP injector cases. As illustrated in **Figure 9**, one aspect of this adaptation is the ability in VIHP to adjust an injection point to position it above an impermeable barrier layer. **Figure 10** illustrates the effect of this adaptation, showing accelerated oil production by VIHP (top panel) compared to SAGD (bottom panel) in the heterogeneous reservoir environment.

[0046] The numerical results of the SAGD and VIHP simulations are provided in the graphs of **Figures 11, 12 and 13**. By 500 days, in both heterogeneous and homogeneous simulations, oil production was accelerated by about 20% using VIHP compared to SAGD. The VIHP method initially required more steam to be injected, compared to the circulation phase of SAGD. Consequently, by 500 days 13% more steam was injected in VIHP compared to SAGD. The overall cumulative steam to oil ratio (CSOR) in both VIHP and SAGD declined over time, from about 2 for SAGD to about 1.75 for VIHP. In alternative embodiments, steam injection in VIHP may of course vary. In this Example, a very generous amount of steam of 100 t/d was injected for the first 50 days. Similar studies showed that, in alternative processes, about 60 t/d per well could be injected to achieve pseudo-steam chambers development with communication between the injectors and the horizontal producer.

Conclusion

[0047] Although various embodiments of the invention are disclosed herein, many adaptations and modifications may be made within the scope of the invention in

accordance with the common general knowledge of those skilled in this art. For example, any one or more of the injection, production or vent wells may be adapted from well segments that have served or serve a different purpose, so that the well segment may be re-purposed to carry out aspects of the invention, including for example the use of multilateral wells as injection, production and/or vent wells. Such modifications include the substitution of known equivalents for any aspect of the invention in order to achieve the same result in substantially the same way. Numeric ranges are inclusive of the numbers defining the range. The word "comprising" is used herein as an open-ended term, substantially equivalent to the phrase "including, but not limited to", and the word "comprises" has a corresponding meaning. As used herein, the singular forms "a", "an" and "the" include plural referents unless the context clearly dictates otherwise. Thus, for example, reference to "a thing" includes more than one such thing. Citation of references herein is not an admission that such references are prior art to the present invention. The invention includes all embodiments and variations substantially as hereinbefore described and with reference to the examples and drawings.

CLAIMS

1. A process for removing fluids from a subterranean deposit, the process comprising:
 - a) selecting a recovery zone bearing a heavy oil in a hydrocarbon reservoir, the recovery zone having a longitudinal axis formed by:
 - i) a generally horizontal segment of a production well;
 - ii) a plurality of generally parallel vertical segments of injection wells that are horizontally offset along the longitudinal axis of the recovery zone, each injection well terminating at an injection well bottom that is juxtaposed to and vertically spaced apart above the horizontal segment of the production well; and;
 - b) initiating contemporaneous mobilization and production of heavy oil by injecting an injection fluid through the vertical segments of the injection wells to injection points proximal to the injection well bottoms, mobilizing heavy oil in the vicinity of the production well, with mobilized heavy oil flowing by a gravity dominated process to the production well, so as to form an expanding chamber depleted of hydrocarbons between each injection well bottom and the production well;
 - c) vertically re-arranging the injection points of one or more injection wells following initiation of mobilization and production of heavy oil, so that the injection point moves upwardly away from the horizontal segment of the production well, within the expanding chamber; and,
 - d) recovering mobilized heavy oil from the reservoir through the production well while injecting the injection fluid through the injection points, so that the expanding chambers associated with a plurality of injection wells coalesce to form one or more common chambers depleted of hydrocarbons.

2. The process of claim 1, wherein the reservoir comprises a plurality of vertically spaced apart stratified recovery zones, the stratified recovery zones each being separated by one or more heterogeneous barrier strata having reduced permeability compared to adjacent recovery zones.

3. The process of claim 2, wherein the plurality of vertically spaced apart stratified recovery zones comprises recovery zones in two or more geological formations.
4. The process of claim 3, wherein the geological formations comprise Wabiskaw and McMurray formations.
5. The process of claim 2, wherein the plurality of vertically spaced apart stratified recovery zones consists of recovery zones in a single heterogeneous geological formation.
6. The process of any one of claims 2 to 5, wherein the step of vertically re-arranging the injection points of one or more injection wells comprises moving the injection point in an injection well from below a barrier strata to above the barrier strata.
7. The process of any one of claims 2 to 6, wherein the step of vertically re-arranging the injection points of one or more injection wells comprises drilling an injection arm on an existing vertical well, and moving the injection point in said existing injection well from below a barrier strata to a position in the injection arm above the barrier strata.
8. The process of any one of claims 1 to 7, further comprising data logging one or more of the injection wells to obtain stratigraphic information about the subterranean deposit.
9. The process of any one of claims 1 to 8, further comprising drilling the horizontal segment of the production well by ranging from one vertical well to the next along the longitudinal axis.
10. The process of any one of claims 1 to 8, further comprising drilling one or more of the vertical wells by ranging to the horizontal segment of the production well along the longitudinal axis.

11. The process of any one of claims 1 to 10, wherein the injection fluid comprises steam.
12. The process of claim 11, wherein the recovery zone comprises a steam chamber.
13. The process of any one of claims 1 to 12, wherein the injection fluid comprises a solvent.
14. The process of any one of claims 1 to 13, further comprising producing fluids through one or more of the injection wells.
15. The process of claim 14, comprising producing non-condensing gases through one or more of the injection wells.
16. The process of claim 15, wherein non-condensing gases are collected through one or more of the injection wells at a collection point that is within an upper portion of the recovery zone.

Figure 1

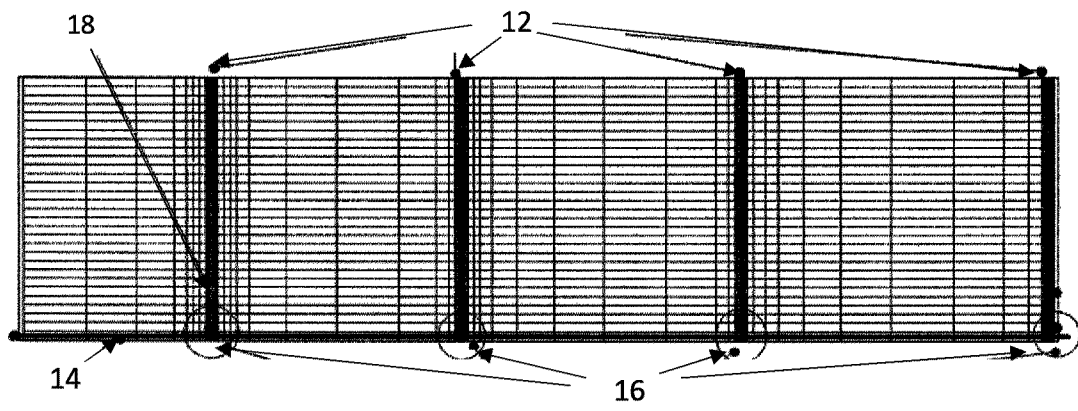
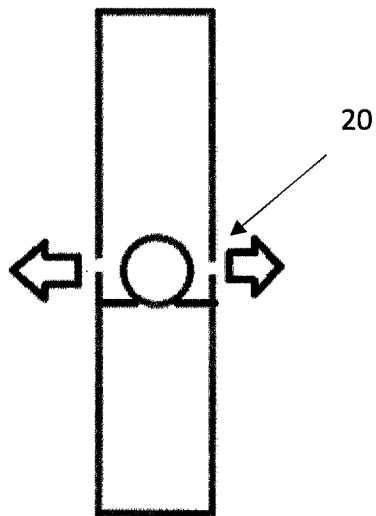


Figure 2



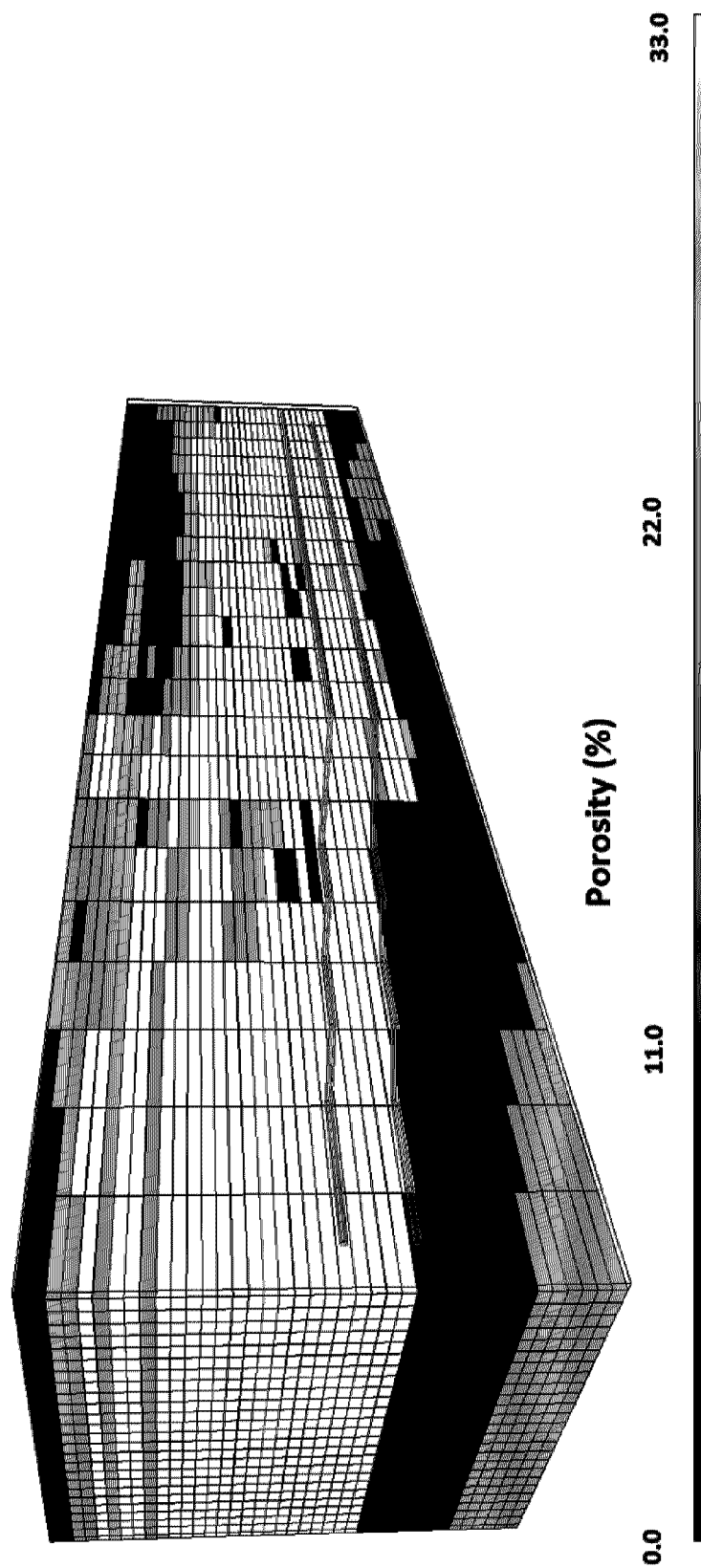
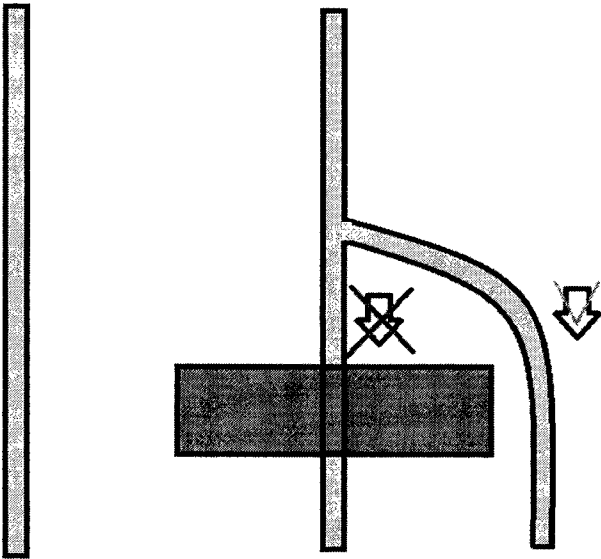


Figure 3

Figure 4



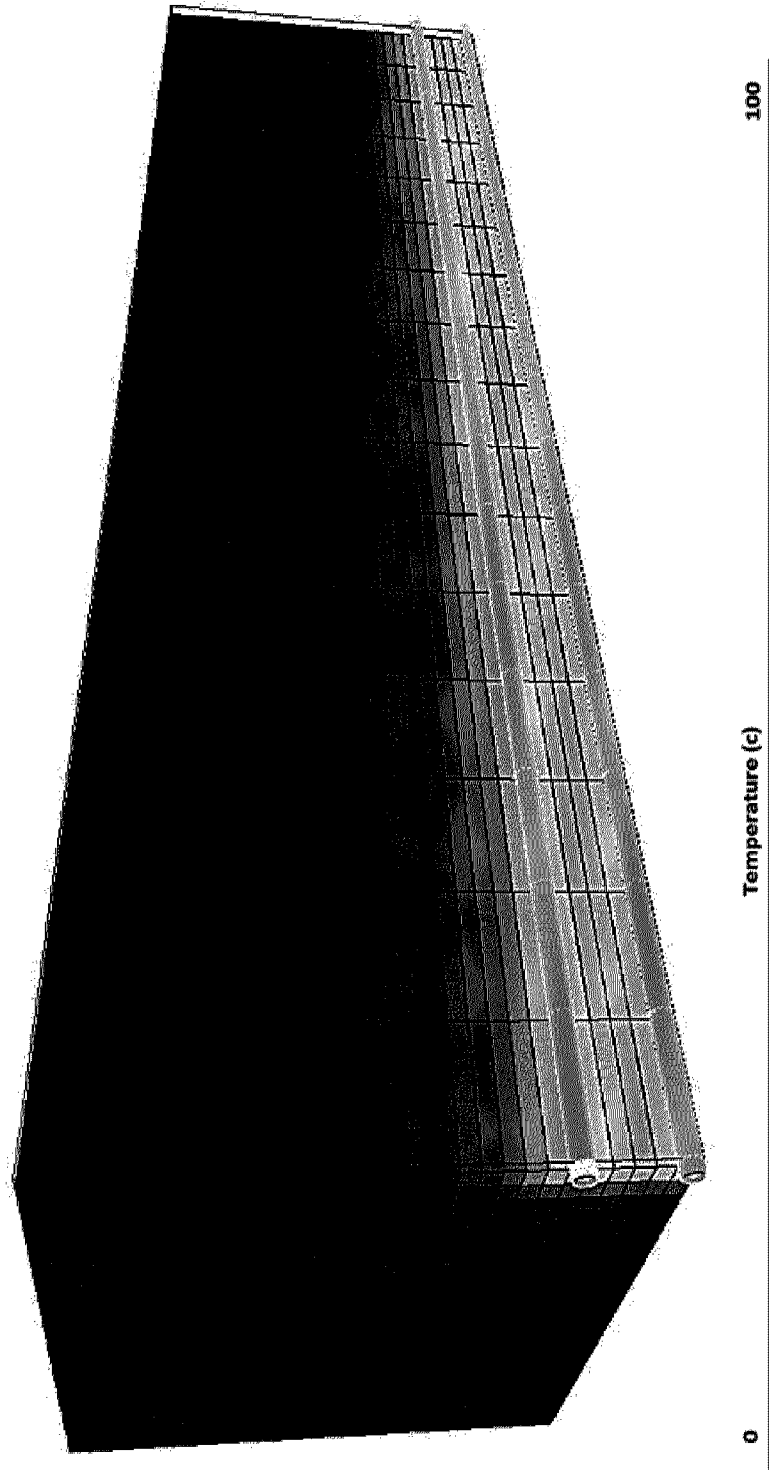


Figure 5

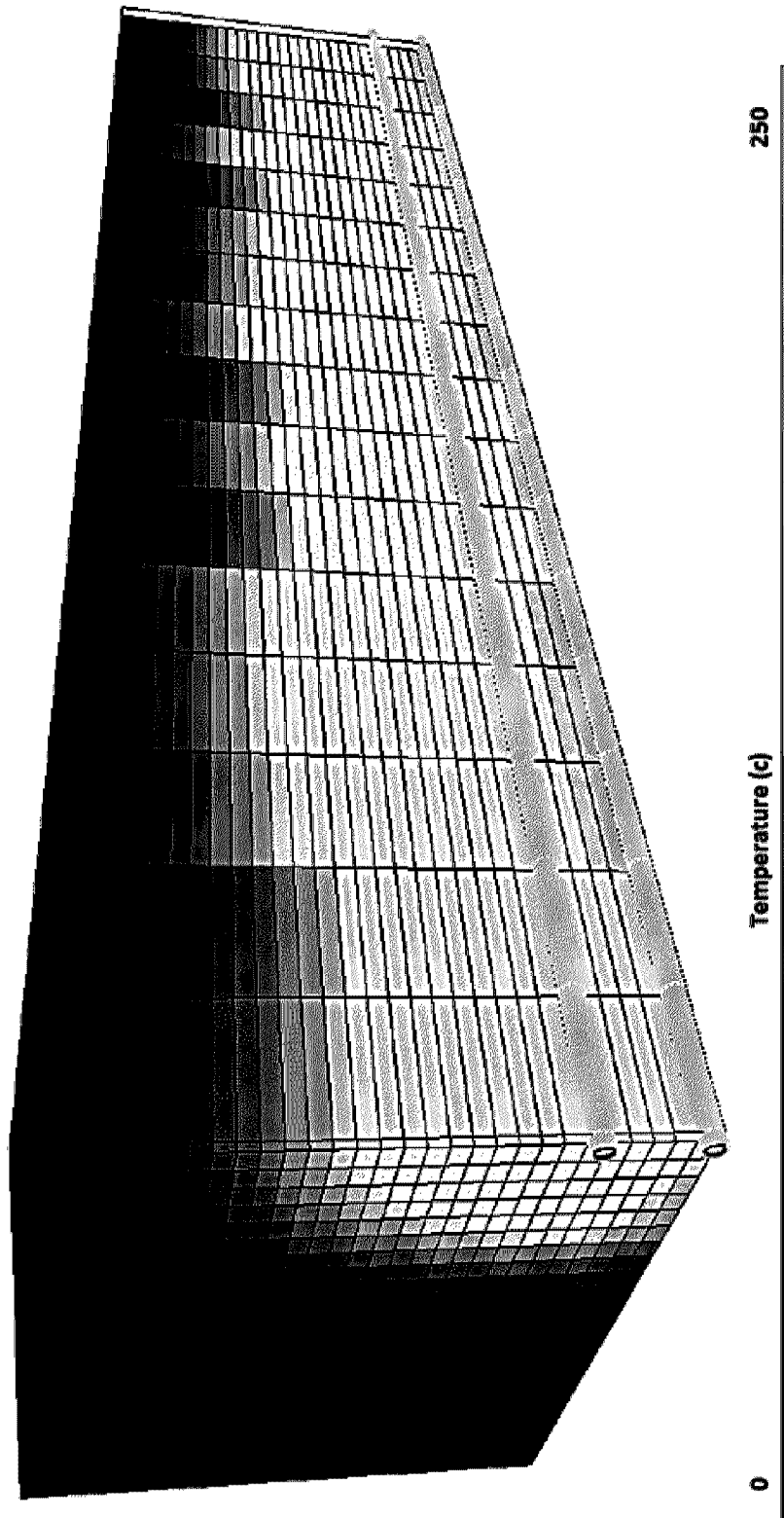


Figure 6

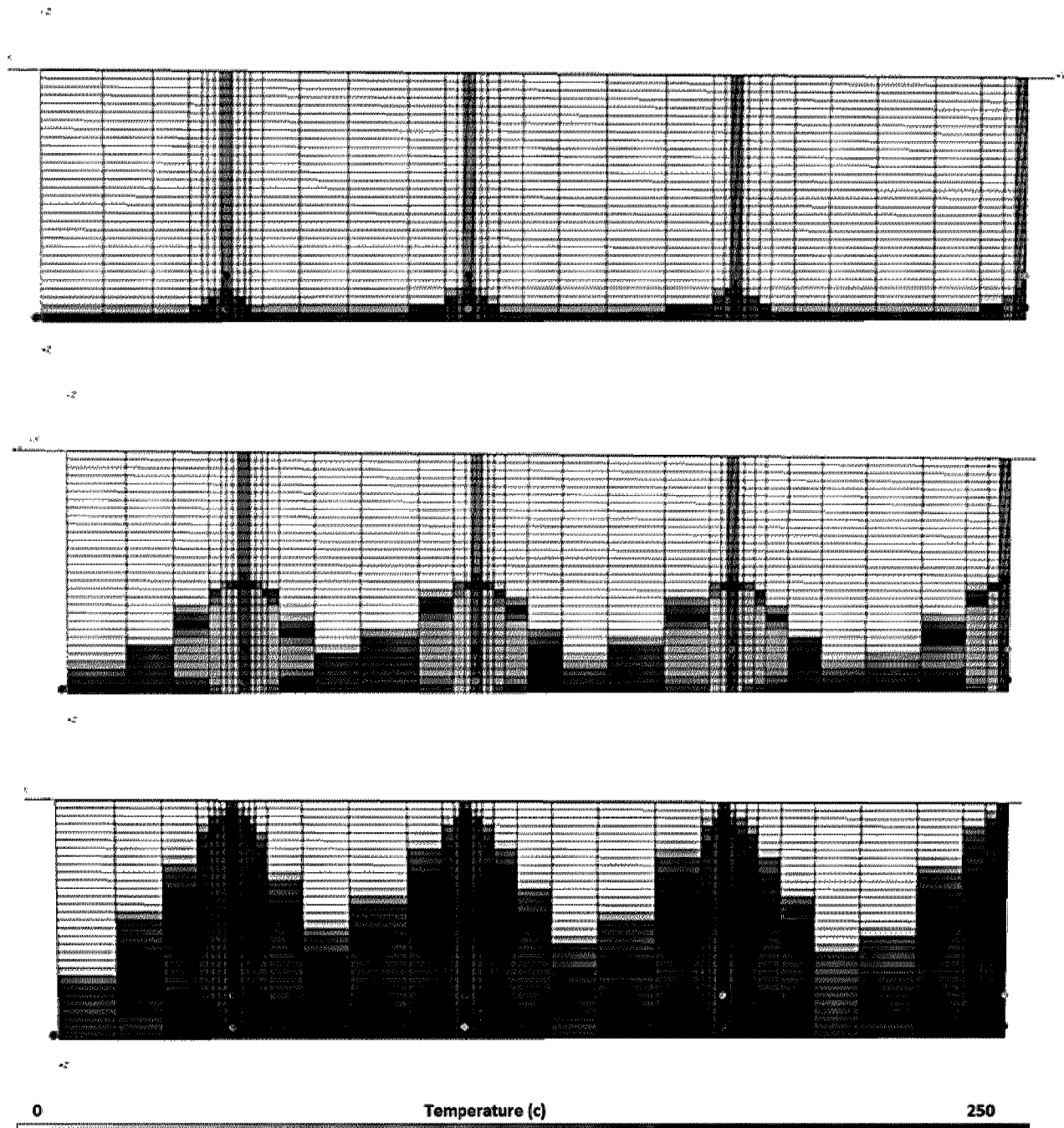


Figure 7

Figure 8

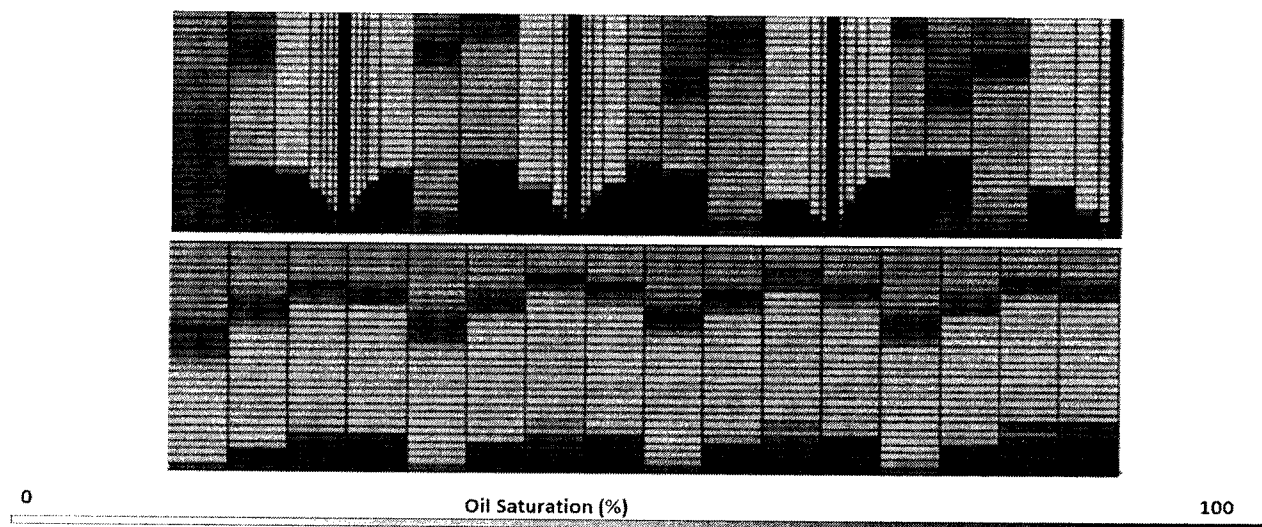


Figure 9

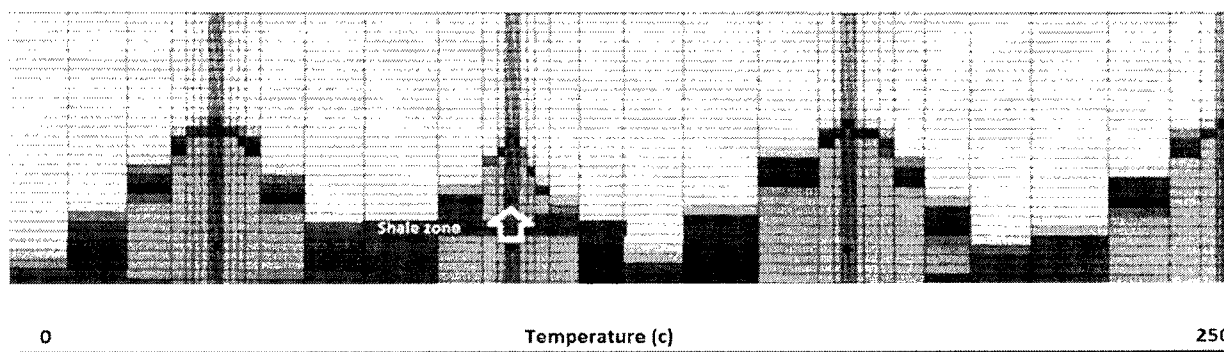


Figure 10

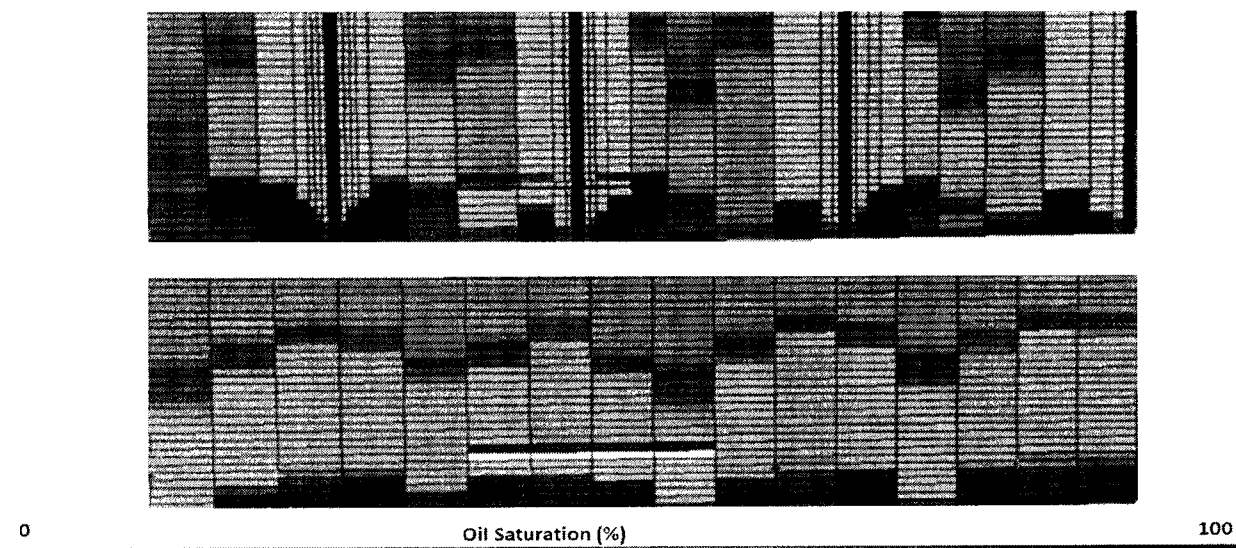


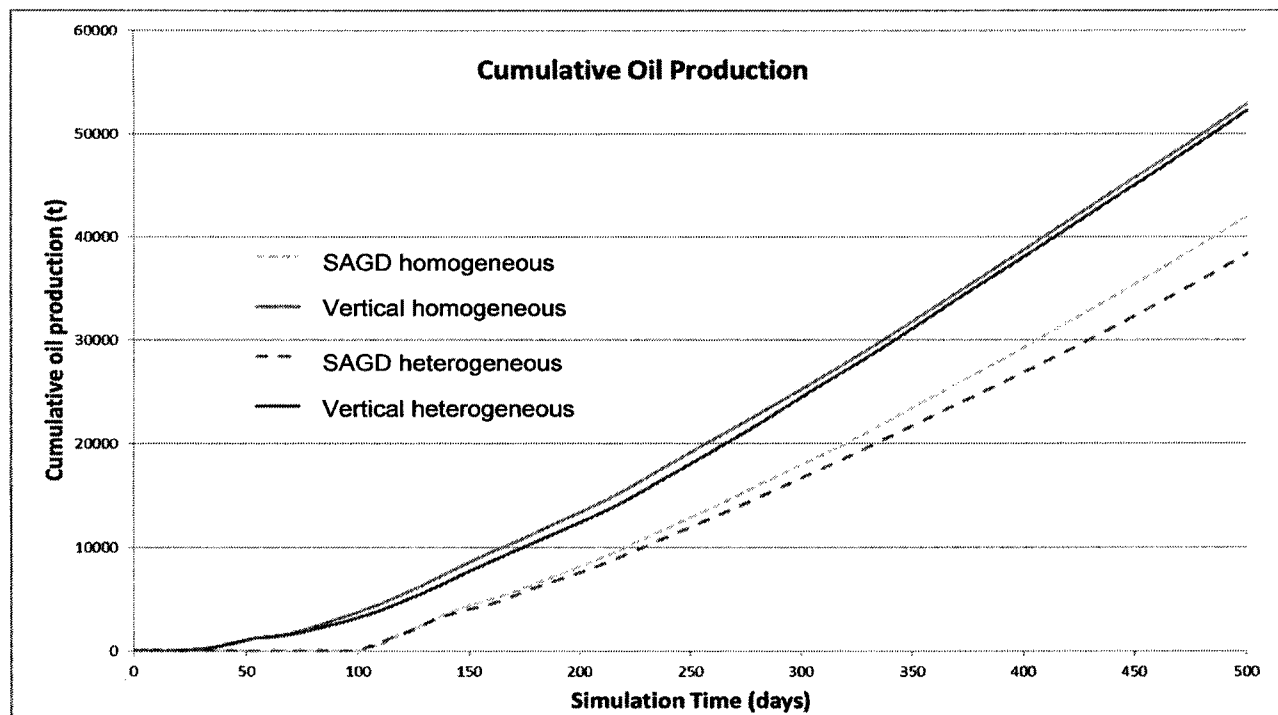
Figure 11

Figure 12

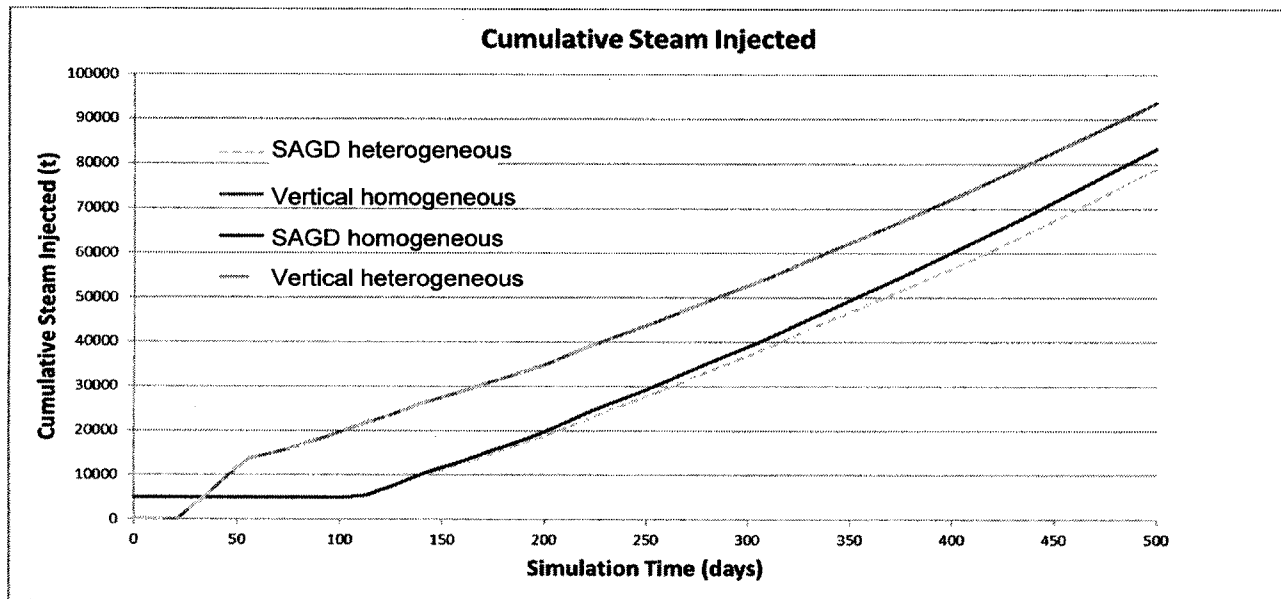


Figure 13