SW-SAGD with multiple injection points
FIGURE 1A: SAGD (prior art)

FIGURE 1B: SAGD steam chamber (prior art)
FIGURE 3: SW-SAGD with center injection

FIGURE 4: SW-SAGD with multiple injection points
Simulated oil saturation profiles of (from left to right) (A) conventional SW-SAGD, (B) SW-SAGD with center injection point (half of full well length by element of symmetry), and (C) SW-SAGD with two injection points (quarter of full well length by element of symmetry) after 3 years of steam injection.

Simulated temperature profiles of (from left to right) (A) conventional SW-SAGD, (B) SW-SAGD with center injection point (half of full well length by element of symmetry), and (C) SW-SAGD with two injection points (quarter of full well length by element of symmetry) after 3 years of steam injection.
SW-SAGD WITH BETWEEN HEEL AND TOE INJECTION

PRIORITY CLAIM

[0001] This application is a non-provisional application which claims benefit under 35 USC §119(e) to U.S. Provisional Application Ser. No. 62/153,269 filed Apr. 27, 2015, entitled “SW-SAGD WITH BETWEEN HEEL AND TOE INJECTION,” which is incorporated herein in its entirety.

FEDERALLY SPONSORED RESEARCH STATEMENT

[0002] Not Applicable.

REFERENCE TO MICROFICHE APPENDIX

[0003] Not applicable.

FIELD OF THE DISCLOSURE

[0004] This disclosure relates generally to methods that can advantageously produce oil using steam-based mobilizing techniques. In particular, it relates to improved single well gravity drainage techniques with better steam chamber development than previously available.

BACKGROUND OF THE DISCLOSURE

[0005] Oil sands are a type of unconventional petroleum deposit, containing naturally occurring mixtures of sand, clay, water, and a dense and extremely viscous form of petroleum technically referred to as “bitumen,” but which may also be called heavy oil or tar. Bitumen is so heavy and viscous (thick) that it will not flow unless heated or diluted with lighter hydrocarbons. At room temperature, bitumen is much like cold molasses, and the viscosity can be in excess of 1,000,000 cp.

[0006] Due to their high viscosity, these heavy oils are hard to mobilize, and they generally must be heated in order to produce and transport them. One common way to heat bitumen is by injecting steam into the reservoir. Steam Assisted Gravity Drainage or “SAGD” is the most extensively used technique for in situ recovery of bitumen resources in the McMurray Formation in the Alberta Oil Sands.

[0007] In a typical SAGD process, two horizontal wells are stacked one over the other and vertically spaced by 4 to 10 meters (m). See FIG. 1. The production well is located near the bottom of the pay and the steam injection well is located directly above and parallel to the production well. Steam is injected continuously into the injection well, where it rises in the reservoir and forms a steam chamber. With continuous steam injection, the steam chamber will continue to grow upward and laterally into the surrounding formation. At the interface between the steam chamber and cold oil, steam condenses and heat is transferred to the surrounding oil. This heated oil becomes mobile and drains, together with the condensed water from the steam, into the production well due to gravity segregation within steam chamber.

[0008] The use of gravity gives SAGD an advantage over conventional steam injection methods. SAGD employs gravity as the driving force and the heated oil remains warm and movable when flowing toward the production well. In contrast, conventional steam injection displaces oil to a cold area, where its viscosity increases and the oil mobility is again reduced.

[0009] Although quite successful, SAGD does require large amounts of water in order to generate a barrel of oil. Some estimates provide that 1 barrel of oil from the Athabasca oil sands requires on average 2 to 3 barrels of water, and it can be much higher, although with recycling the total amount can be reduced. In addition to using a precious resource, additional costs are added to convert those barrels of water to high quality steam for down-hole injection. Therefore, any technology that can reduce water or steam consumption has the potential to have significant positive environmental and cost impacts.

[0010] Additionally, SAGD is less useful in thin stacked pay-zones, because thin layers of impermeable rock in the reservoir can block the expansion of the steam chamber leaving only thin zones accessible, thus leaving the oil in other layers behind. Further, the wells need a vertical separation of about 4-5 meters in order to maintain the steam trap. In wells that are closer, live steam can break through to the producer well, resulting in enlarged slots that permit significant sand entry, well shutdown and damage to equipment.

[0011] Indeed, in a paper by Shin & Polkhar (2005), the authors simulated reservoir conditions to determine which reservoirs could be economically exploited. The simulation results showed that for Cold Lake-type reservoirs, a net pay thickness of at least 20 meters was required for an economic SAGD implementation. A net pay thickness of 15 m was still economic for the shallow Athabasca-type reservoirs because of the high permeability of this type of reservoir, despite the very high bitumen viscosity at reservoir conditions. In Peace River-type reservoirs, net pay thicker than 30 meters was expected to be required for a successful SAGD performance due to the low permeability of this type of reservoir. The results of the study indicate that the shallow Athabasca-type reservoir, which is thick with high permeability (high kh), is a good candidate for SAGD application, whereas Cold Lake and Peace River-type reservoirs, which are thin with low permeability, are not as good candidates for conventional SAGD implementation.

[0012] In order to address the thin payzone issue, some petroleum engineers have proposed a single wellbore steam assisted gravity drainage or “SW-SAGD.” See e.g., FIG. 2A. In SW-SAGD, a horizontal well is completed and assumes the role of both injector and producer. In a typical case, steam is injected at the toe of the well, while hot reservoir fluids are produced at the heel of the well, and a thermal packer is used to isolate steam injection from fluid production (FIG. 2A).

[0013] Another version of SW-SAGD uses no packers, simply tubing to segregate flow. Steam is injected at the end of the horizontal well (toe) through an isolated concentric coiled tubing (ICTT) with numerous orifices. In FIG. 2B a portion of the injected steam and the condensed hot water returns through the annulus to the well’s vertical section (heel). The remaining steam, grows vertically, forming a chamber that expands toward the heel, heating the oil, lowering its viscosity and draining it down the well’s annular by gravity, where it is pumped up to the surface through a second tubing string.

[0014] Advantages of SW-SAGD might include cost savings in drilling and completion and utility in relatively thin
reservoirs where it is not possible to drill two vertically spaced horizontal wells. Basically since there is only one well, instead of a well pair, start up costs are only half that of conventional SAGD. However, the process is technically challenging and the method seems to require even more steam than conventional SAGD.

Field tests of SW-SAGD are not extensively documented in the literature, but the available evidence suggests that there is considerable room to optimize the SW-SAGD process.

For example, Falk overviewed the completion strategy and some typical results for a project in the Cactus Lake Field, Alberta Canada. A roughly 850 m long well was installed in a region with 12 to 16 m of net pay to produce 12° API gravity oil. The reservoir contained clean, unconsolidated, sand with 3400 and permeability. Apparently, no attempts were made to preheat the reservoir before initiation of SW-SAGD. Steam was injected at the toe of the well and oil produced at the heel. Oil production response to steam was slow, but gradually increased to more than 100 m³/d. The cumulative steam-oil ratio was between 1 and 1.5 for the roughly 6 months of reported data.

McComack also described operating experience with nineteen SW-SAGD installations. Performance for approximately two years of production was mixed. Of their seven pilot projects, five were either suspended or converted to other production techniques because of poor production. Positive results were seen in fields with relatively high reservoir pressure, relatively low oil viscosity, significant primary production by heavy-oil solution gas drive, and/or insignificant bottom-water drive. Poor results were seen in fields with high initial oil viscosity, strong bottom-water drive, and/or sand production problems. Although the authors noted that the production mechanism was not clearly understood, they suspected that the mechanism was a mixture of gravity drainage, increased primary recovery because of near-wellbore heating via conduction, and hot water induced drive/drainage.

Moriens (2007) simulated SW-SAGD using CMG-STARS, attempting to improve the method by adding a pre-heating phase to accelerate the entrance of steam into the formation, before beginning a traditional SW-SAGD process. Two processes were modeled, as well as conventional SW-SAGD and dual well SAGD. The improved processes tested were 1) Cyclic injection-soaking-production repeated three times (20, 10 and 30 days for injection, soaking and production respectively), and 2) Cyclic injection repeated three times as in 1), but with the well divided into two portions by a packer, where preheat steam was injected at the toe and center and circulated throughout the well, but production occurring only in the producing heel half with toe steam injection.

They found that the cyclic preheat period provided better heat distribution in the reservoir and reduces the required injection pressure, although, it increased the waiting time for the continuous injection process. Additionally, the division of the well by a packer and the injection of the steam in two points, in the middle and at the extremity of the well, helped the distribution of the heat in the formation and favor oil recovery in the cyclical injection phase. They also found that in the continuous injection phase, the division of the well induces an increase of the volume of the steam chamber, and improved the oil recovery in relation to the SW-SAGD process. Also, an increase of the blind interval (blank pipe), between the injection and production passages, increased the difference of the pressure and drives the displaced oil in the injection section into the production area, but caused imprisonment of the oil in the injection section, reducing the recovery factor.

Overall, the authors concluded that modifications in SW-SAGD operation strategies can lead to better recovery factors and oil steam ratios than those obtained with the DW-SAGD process, but that SW-SAGD performance was highly variable.

It is noted that these authors did use central (and toe) injection during the preheat or startup phase. However, the steam was allowed to travel the length of the well, thus the entire well was preheated. Further, actual production phase was the same as usual, with toe injection and heel production. Since the steam is injected at the toe segment, it is expected that the oil from the steam end, at least part of it, will not be recoverable.

Although beneficial, the SW-SAGD methodology could be further developed to further improve its cost effectiveness. This application addresses some of those needed improvements.

**SUMMARY OF THE DISCLOSURE**

The conventional SW-SAGD utilizing one single horizontal well to inject steam into reservoir through toe and produce liquid (oil and water) through mid heel of the well has potential for thin-zone applications where placing two horizontal wells with 5 m vertically apart required in the SAGD is technically and economically challenging. SW-SAGD, however, exhibits several disadvantages leading to slow steam chamber growth and low oil rate.

First of all, SW-SAGD is not efficient in developing the steam chamber. Due to the arrangement of injection and production points in the conventional SW-SAGD, the steam chamber can grow only in one side towards the heel. In other words, only one half of the surface area surrounding the steam chamber is available for heating and draining oil.

Secondly, a large portion of the horizontal well length perforated for production does not actually contribute to oil production until the steam chamber expands over the whole length. This is particularly true during the early stage where only a small portion of the well close to the toe collects oil.

This disclosure proposes instead to use variations of steam injection point location and number to improve the recovery performance. The essential idea of the invention is to allow full development of steam chamber from both sides and increase the effective production well length.

**FIG. 1B shows schematically a simple, but effective (as demonstrated later by simulation) process modified from the conventional SW-SAGD, in which the steam injection point is placed in the middle of the horizontal well. The toe and heel sections of the horizontal well, isolated from the steam injection portion by thermal packers within the wellbore, are perforated and serve as producer wells to collect oil and condensed water.**

As illustrated in FIG. 3, the steam chamber can now grow from both sides, with the effective thermal and drainage interfaces virtually doubled. Consequently, the effective production well length is doubled, resulting in a significant uplift in oil production rate. To further improve the performance SW-SAGD, multiple steam injection points
can be introduced into the wellbore to initiate and grow a serial of steam chambers simultaneously.

[0029] FIG. 4 gives an example with two injection points, one at ¼ well length from the heel and the other ¾ well length from the heel. The SW-SAGD with multiple steam injection points can significantly accelerate the oil recovery by engaging more well length into effective production. The number of the steam injection points and intervals between them normally need to be determined and optimized based on the reservoir properties and economics.

[0030] It is worth pointing out that implementing center or multi-injection points within a single wellbore adds complexity to the wellbore design, and consequently well cost (as compared to standard SW-SAGD). For example, the well completion will require packers on either side of the steam injection points, and the ICCT will require outlets for steam if multi-point injection methods are used. Nevertheless, the proposed invention presents a big potential, and the increased cost is incremental as compared with the cost of saving in injector well drilling. Further, as shown in FIGS. 7 and 8, the increased recovery herein is a likely game-changer for SW-SAGD applications, especially as applied to thin-zone bitumen reservoirs.

[0031] The method is otherwise similar to SAGD, which requires steam injection (often in both wells) to establish fluid communication between wells (not needed here) as well as a steam chamber. When the steam chamber is well developed, injection proceeds in only the injectors, and production begins at the producer. Alternatively, the startup or preheat period can be reduced or even eliminated.

[0032] Preferably, the method includes preheat cyclic steam phases, wherein steam is injected throughout both injector and producer segment, for e.g. 20-50 days, then allowed to soak into the reservoir, e.g., for 10-30 days, and this preheat phase is repeated two or preferably three times. This ensures adequate steam chamber growth along the length of the well.

[0033] Also preferred the steam injection can be combined with solvent injection or non-condensable gas injection, such as CO₂, as solvent dilution and gas lift can assist in recovery.

[0034] The invention can comprise any one or more of the following embodiments, in any combination(s) thereof:

[0035] An improved method of producing heavy oils from a SW-SAGD, wherein steam in injected into a toe end of a horizontal well to mobilize oil which is then produced at a heel end of said horizontal well, the improvement comprising providing one or more injection points for steam between said heel end and said toe end, thus improving a CSOR of said horizontal well at a time period as compared to a similar well with steam injection only at said toe end.

[0036] A method of producing heavy oils from a reservoir by single well steam and gravity drainage (SW-SAGD), comprising: providing a horizontal well below a surface of a reservoir; said horizontal well having a toe end and a heel end and a middle therebetween; injecting steam into one or more injection points between said toe end and said heel end; and simultaneously (with said steam injection) producing mobilized heavy oil; wherein said method produces more oil at a time point than a similar SW-SAGD well with steam injection only at said toe.

[0037] A well configuration for producing heavy oils from a reservoir by single well steam and gravity drainage (SW-SAGD), comprising: a horizontal well in a subsurface reservoir; said horizontal well having a toe end and a heel end and having at least three segments comprising: at least two production segments bracketing at least one injection segment; said production segments fitted for production; and said injection segments fitted for injection.

[0038] A method or configuration as herein described, wherein each injection point is separated from a production segment by at least two thermal packers.

[0039] A method or configuration as herein described, wherein an injection point is at said middle.

[0040] A method or configuration as herein described, wherein two injection points are at about ¼ and ¾ of a horizontal length of said well.

[0041] A method or configuration as herein described, said at least two injection segments fitted with tubing having two orifices to inject steam into said two injection segments.

[0042] A method as herein described, wherein production and injection take place simultaneously.

[0043] A method as herein described wherein injected steam includes solvent.

[0044] A method as herein described wherein said method includes a preheating phase wherein steam is injected along the entire length of the well.

[0045] A method or configuration as herein described wherein said method includes a cyclic preheating phase comprising a steam injection period along the entire length of the well followed by a soaking period.

[0046] A method as herein described wherein said method includes a pre-heating phase comprising a steam injection in both the injection segment and the production segment followed by a soaking period.

[0047] Preferably, two or three cyclic preheating phases are used. Preferably the soaking period is 10-30 days or about 20 days.

[0048] “SW-SAGD” as used herein means that a single well serves both injection and production purposes, but nonetheless there may be an array of SW-SAGD wells to effectively cover a given reservoir. This is in contrast to conventional SAGD where the injection and production wells are separate during production phase, necessitating a wellpair at each location.

[0049] As used herein, “preheat” or “startup” is used in a manner consistent with the art. In SAGD the preheat stage usually means steam injection throughout both wells until the steam chamber is well developed and the two wells are in fluid communication. Thus, both wells are fitted for steam injection. Later during production, the production well is fitted for production, and steam injected into the injector well only. In SW-SAGD, the meaning is the same, except that there is only a single well. Thus, preheat means steam injection throughout the well (e.g., no packers) in order to develop a steam chamber along the entire length of the well.

[0050] As used herein, “cyclic preheat” is used in a manner consistent with the art, wherein the steam is injected, preferably throughout the horizontal length well, and left to soak for a period of time, and any oil collected. Typically the process is then repeated two or more times. Steam injection throughout the length of the well can be achieved herein by merely removing or opening packers, such that steam travels the length of the well, exiting any slots or perforations used for production.

[0051] As used wherein, a “production phase” is that phase where steam injection and production occur simultaneously, and is understood in the art to be different from a
“preheat” or “startup” phase, where steam is injected for preheat purposes and the well configuration is different. The invention herein relates to steam injection during production phase that occurs at one or more locations between the heel and toe. Since there is only a single well, packers are typically required to separate the steam injection and production segments so that they can occur simultaneously.

After preheat or cyclic preheat, the well is used for production, and steam injection occurs only at the points designated hereunder, with packers and preferably with a blank pipe separating injection section(s) from production sections. The blank pipe, with relatively short length or preferably controllable length during operation, may help provide differential pressure and thus minimize steam breakthrough at the production section. Injection sections need not be large herein, and can be on the order of <1-100 m, or 1-50 m or 20-40.

The ideal length of blank pipe will vary according to reservoir characteristics, oil viscosity as well as injection pressures and temperatures, but a suitable length is in the order of 10-40 feet or 20-30 feet of blank liner. It may also be possible to use a sliding sleeve and thus allow the benefits of a blind interval, yet recover the oil behind the blind interval by sliding the sleeve in one direction or the other, thus sliding the blind interval. It may also be possible to substitute FCDs for the blank pipe.

A suitable arrangement might thus be a 300-500 meter long production passage, 10-40 meter blind interval, packer, <140 meter long injection passage followed by another packer, 10-40 meter blind interval and 300-500 meter production passage. Another arrangement might have two injection points: 300 meter production, 10-20 blind interval, packer, 1-10 injection, packer, 10-20 blind interval, 600 meter production, 10-20 blind interval, packer, 1-10 m injection, packer, 10-20 blind interval, 300 meter production. Yet another arrangement might be 200 meter production, 10-20 blind interval, packer, 1-10 injection, packer, 10-20 blind interval, 400 meter production, 10-20 blind interval, packer, 1-10 m injection, packer, 10-20 blind interval, 400 meter production, 10-20 blind interval, packer, 1-10 injection, packer, 10-20 blind interval, and 200 meter production.

By “heel end” herein we include the first joint in the horizontal section of the well, or the first two joints.

By “toe end” herein we include the last joint in the horizontal section of the well, or the last two joints.

By “middle” herein we refer to 25-75% of the horizontal well length, but preferably from 40-60% or 45-55%.

By “between the toe end and the heel end”, we mean an injection point that lies between the first and last joint or two of the ends of the horizontal portion of the well.

As used herein, flow control device “FCD” refers to all variants of tools intended to passively control flow into or out of wellbores by choking flow (e.g., creating a pressure drop). The FCD includes both inflow control devices “ICDs” when used in producers and outflow control devices “OCDS” when used in injectors. The restriction can be in form of channels or nozzles/orifices or combinations thereof, but in any case the ability of an FCD to equalize the inflow along the well length is due to the difference in the physical laws governing fluid flow in the reservoir and through the FCD. By restraining, or normalizing, flow through high-rate sections, FCDs create higher drawdown pressures and thus higher flow rates along the bore-hole sections that are more resistant to flow. This corrects uneven flow caused by the heel-toe effect and heterogeneous permeability.

By “providing” a well, we mean to drill a well or use an existing well. The term does not necessarily imply contemporaneous drilling because an existing well can be retrofitted for use, or used as is.

By being “lifted” for injection or production what we mean is that the completion has everything is needs in terms of equipment needed for injection or production.

“Vertical” drilling is the traditional type of drilling in oil and gas drilling industry, and includes any well <45° of vertical.

“Horizontal” drilling is the same as vertical drilling until the “kickoff point” which is located just above the target oil or gas reservoir (pay-zone), from that point deviating the drilling direction from the vertical to horizontal. By “horizontal” what is included is an angle within 45° (<45°) of horizontal. Of course every horizontal well has a vertical portion to reach the surface, but this is conventional, understood, and typically not discussed.

A “perforated liner” or “perforated pipe” is a pipe having a plurality of entry-exits holes throughout the extent of steam and entry of hydrocarbon. The perforations may be round or long and narrow, as in a “slotted liner,” or any other shape.

A “blank pipe” or “blank liner” is a joint that lacks any holes.

A “packer” refers to a downhole device used in almost every completion to isolate the annulus from the production conduit, enabling controlled production, injection or treatment. A typical packer assembly incorporates a means of securing the packer against the casing or liner wall, such as a slug arrangement, and a means of creating a reliable hydraulic seal to isolate the annulus, typically by means of an expandable elastomeric element. Packers are classified by application, setting method and possible retrievability.

A “joint” is a single section of pipe.

The use of the word “a” or “an” when used in conjunction with the term “comprising” in the claims or the specification means one or more than one, unless the context dictates otherwise.

The term “about” means the stated value plus or minus the margin of error of measurement or plus or minus 10% if no method of measurement is indicated.

The use of the term “or” in the claims is used to mean “and/or” unless explicitly indicated to refer to alternatives only if or if the alternatives are mutually exclusive.

The terms “comprise”, “have”, “include” and “contain” (and their variants) are open-ended linking verbs and allow the addition of other elements when used in a claim.

The phrase “consisting of” is closed, and excludes all additional elements.

The phrase “consisting essentially of” excludes additional material elements, but allows the inclusions of non-material elements that do not substantially change the nature of the invention.

The following abbreviations are used herein:

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>bbl</td>
<td>Oil barrel, bbls in plural</td>
</tr>
<tr>
<td>CPSW-SAGD</td>
<td>Center point injection SW-SAGD</td>
</tr>
<tr>
<td>CSOR</td>
<td>Cumulative Steam to oil ratio</td>
</tr>
</tbody>
</table>
BRIEF DESCRIPTION OF THE DRAWINGS

Fig. 1A shows traditional SAGD wellpair, with an injector well a few meters above a producer well. Fig. 1B shows a typical steam chamber. Fig. 2A shows a SW-SAGD well, wherein the same well functions for both steam injection and oil production. Steam is injected into the toe (in this case the toe is updip of the heel), and the steam chamber grows towards the heel. Steam control is via packer. Fig. 2B shows another SW-SAGD well configuration wherein steam is injected via ICCT, and a second tubing is provided for hydrocarbon removal. Fig. 3 shows the center point injection SW-SAGD (CPSW-SAGD).

Fig. 4 shows multi-point injection SW-SAGD (MP西南-SAGD). One injection point is situated at ¼ well length from the heel and the other ¾ well length from the heel, and each steam chamber grows in both directions, meeting in the middle of the well.

Fig. 5 shows simulated oil saturation profiles of (A) conventional SW-SAGD, (B) SW-SAGD with center injection point (half of full well length shown), and (C) SW-SAGD with two injection points (quarter of full well length shown) after 3 years of steam injection. All simulations performed with CMG-Stars using a fine grid block. Fig. 6 shows simulated temperature profiles of (A) conventional SW-SAGD, (B) CPSW-SAGD with center injection point (half of full well length shown), and (C) MP西南-SAGD with two injection points (quarter of full well length shown) after 3 years of steam injection.

Fig. 7 shows a comparison of oil production rate. Note that the End-Injector case is conventional SW-SAGD, the Center-Injector case is CPSW-SAGD with a center injection point, and the Two-Injector case is MP西南-SAGD with two injection points spaced for equally sized steam chambers.

Fig. 8 is a comparison of oil recovery using the same three well configurations as in Fig. 7.

DESCRIPTION OF EMBODIMENTS

The present disclosure provides a novel well configuration and method for SW-SAGD. This novel modification to the conventional single-well SAGD (SW-SAGD) process varies the location and number of steam injection points during the production phase, and the same points can be used in preheat or cyclic preheat.

The conventional SW-SAGD process grows a steam chamber and drains oil by gravity utilizing one single horizontal well with steam injected only at the toe and liquid produced through the rest of the well. SW-SAGD has potential to unlock vast thin-zone (5-20 m pay) oil sand resources where SAGD using well pairs is economically and technically challenging.

However, the conventional SW-SAGD normally suffers from slow steam chamber growth and low oil production rate as the steam chamber can only grow from toe gradually towards the heel. This appears to be very inefficient and seriously limits the usefulness of SW-SAGD.

In this invention, we propose an improved SW-SAGD process with one or more steam injection points between the toe and heel end. For example, a center steam injection point can be used, or multiple steam injection points spaced for equal steam chamber development can be used to significantly accelerate steam chamber growth and oil recovery. The superior recovery performance of the proposed configuration and methods is confirmed by our simulation results.

It is surprising that this elegant solution to the low production level issue with SW-SAGD has never been proposed before. However, one reason is that most SAGD simulations are either run as 2D cross-sections, or as 3D models with relatively large gridding in the wellbore direction (typically 25-100 m), both of which will either eliminate the “end effect” (in the case of 2D simulations), or seriously underestimate it (in the case of large-block 3D simulations). Thus, given the tools typically available to the petroleum engineer, even if the idea was attempted, traditional models would not show any benefit.

Conventional SW-SAGD

The conventional SW-SAGD utilizes one single horizontal well to inject steam into reservoir through toe and produce liquid (oil and water) through mid and heel of the well, as schematically shown in Figs. 2A and B. A steam chamber is expected to form and grow from the toe of the well. Similar to the SAGD process, the oil outside of the steam chamber is heated up with the latent heat of steam, becomes mobile, and drains with steam condensate under gravity towards the production portion of the well. With continuous steam injection through toe and liquid production through the rest of the well, the steam chamber expands gradually towards the heel to extract oil.

Due to the unique arrangement of injection and production, the SW-SAGD can also benefit from pressure drive in addition to gravity drainage as the recovery mechanisms. Also, compared with its counterpart, the traditional dual well or “DW-SAGD” configuration, SW-SAGD requires only one well, thereby saving almost half of well cost. SW-SAGD becomes particularly attractive for thin-zone applications where placing two horizontal wells with the typical 4-10 m vertical separation required in the SAGD is technically and economically challenging.

SW-SAGD, however, exhibits several disadvantages leading to slow steam chamber growth and low oil rate. First of all, SW-SAGD is not efficient in developing the steam chamber. The steam chamber growth depends largely upon the thermal conduction to transfer steam latent heat into cold reservoir and oil drainage under gravity along the chamber interface. Due to the arrangement of injection and production points in the conventional SW-SAGD, the steam chamber can grow only direction towards the heel. In other words, only one half of the surface area surrounding the steam chamber is available for heating and draining oil. Secondly, a large portion of the horizontal well length
perforated for production does not actually contribute to oil production until the steam chamber expands over the whole length. This is particularly true during the early stage where only a small portion of the well close to the toe collects oil.

CPSW-SAGD

[0094] To overcome the aforementioned issues associated with the conventional SW-SAGD, we propose steam injection in between the heel and toe to improve the recovery performance at about the center of the well. By “center” herein, we refer to roughly the center of the longitudinal portion of the well, and do not consider the vertical portion. By doing this, the steam chamber can grow in both directions from roughly the middle. The essential idea is to allow full development of steam chamber from both sides and increase the effective production well length earlier in the process.

[0095] FIG. 3 shows schematically a simple, but effective (as demonstrated later by simulation) process modified from the conventional SW-SAGD, in which the steam injection point is placed in the middle of the horizontal well. The toe and heel sections of the horizontal well, isolated from the steam injection portion by thermal packers (indicated by the boxes with the X therein) within the wellbore, are perforated and serve as producer to collect heated oil and condensed water.

[0096] As illustrated in FIG. 3, the steam chamber can now grow from both sides, with the effective thermal and drainage interfaces virtually doubled. Consequently, the effective production well length is doubled, resulting in a significant uplift in oil production rate.

MPSW-SAGD

[0097] To further improve the performance SW-SAGD, multiple steam injection points can be introduced into the wellbore to initiate and grow a serial of steam chambers simultaneously. FIG. 4 gives an example with two injection points, one at ¼ well length from the heel and the other ¾ well length from the heel. The SW-SAGD with multiple steam injection points can significantly accelerate the oil recovery by engaging more well length into effective production. With two injection points as placed in FIG. 4, the dual steam chambers will each grow in both directions, and meet in roughly the middle of the well.

[0098] The number of the steam injection points and intervals between them normally need to be determined and optimized based on the reservoir properties and economics. It is worth pointing out that implementing multiple steam injection points within a single wellbore adds complexity to the wellbore design and consequently well cost, necessitating the providing of multiple injections points and additional packers. Nevertheless, the proposed invention presents a considerable potential for improving SW-SAGD applications to thin-zone bitumen reservoirs.

Steam Chamber Simulations

[0099] To evaluate the performance of the proposed modification to the conventional SW-SAGD, numerical simulation with a 3D homogeneous model was conducted using Computer Modeling Group® Thermal & Advanced Processes Reservoir Simulator, abbreviated CMG-STARs. CMG-STARs is the industry standard in thermal and advanced processes reservoir simulation. It is a thermal, k-value (KV) compositional, chemical reaction and geomechanics reservoir simulator ideally suited for advanced modeling of recovery processes involving the injection of steam, solvents, air and chemicals.

[0100] The reservoir simulation model was provided the average reservoir properties of Athabasca oil sand, with an 800 m long horizontal well placed at the bottom of a 20 m pay. The simulation considered three cases, the conventional SW-SAGD, CPSW-SAGD with centered injector, and MPSW-SAGD with two injectors (one 200 m and the other 600 m from heel). A smaller than usual grid size was modeled in order to capture the effects (e.g., 1-5 m, preferably 2 m). No startup period was modeled. The modeled operational conditions, including pressure and injection rates, were similar to a typical SAGD operation.

[0101] FIGS. 5 and 6 show the simulated profiles of oil saturation and temperature after 3-year steam injection for the three cases. Note that due to element of symmetry, the case of the SW-SAGD with centered injection point only shows one half of the well length and the case of the SW-SAGD with two injection points shows a quarter of the well length.

[0102] For the conventional SW-SAGD, the steam chamber extends to about ½ of the well length, leaving ½ of the well length not in production. The case with centered steam injection point results in steam chamber development over half of the well length and the case with two injection points show the steam zone over almost 80% of the well length. Thus, simply moving the steam injection point to the middle of the well, and by adding more than one injection point, the steam zone can cover the entire well.

Production Simulations

[0103] In order to prove the benefit of the CPSW-SAGD and MPSW-SAGD we performed production simulations, also using CMG-STARs. FIG. 7 compares the oil production rate of the three cases from above.

[0104] Surprisingly, the oil production rate is almost doubled from the conventional SW-SAGD by placing the injection point in the middle of the well, and is further lifted by 50% when two injection points are implemented.

[0105] The oil rate drop at 1600 days in the case with two injection points is due to the steam chamber coalescence. With two injection points, two steam chambers develop that are separated from each other at the beginning. As steam injection continues, both steam chambers will grow vertically and laterally. Depending on the distance between the two steam injection points, the edges of the two steam chambers will eventually meet somewhere in the mid-point, in a phenomena called “coalescence” of the steam chamber. The sum of surface area of the two chambers is larger before coalescence than after coalescence, because one of the boundaries is shared after coalescence. The heating of oil and resulting oil drainage depends on the surface or contact area. Therefore, it is typical that the oil rate drops when the steam chamber coalesces.

[0106] FIG. 5 shows the comparison of the oil recovery factor, which again illustrates the significant improvement of the described invention over the conventional SW-SAGD.

[0107] We have not yet run a simulation case with 3 injection points, but we expect even faster oil recovery. It is predicted that the wells can thereby be longer to fully realize the benefits of three injection points.
[0108] The simulated pay zone was big at 20 m. However, the relative gain really comes from the surface area increase due to doubling size of the incipient steam chambers. Thus, even with a thinner pay zone, we still expect the same relative performance improvement.

[0109] The following references are incorporated by reference in their entirety for all purposes.


[0113] Faculdade de Engenharia Mecânica, Universidade estadual de Campinas. S8


[0117] US2012043081 Single well steam assisted gravity drainage

[0118] US20130213652 SAGD Steam Trap Control

[0119] US20140000888 Uplifted single well steam assisted gravity drainage system and process

[0120] U.S. Pat. No. 5,626,193 Method for recovering heavy oil from reservoirs in thin formations

1) A method of producing heavy oils from a reservoir by single well steam and gravity drainage (SW-SAGD), comprising:
   a) providing a horizontal well below a surface of a reservoir;
   b) said horizontal well having a toe end and a heel end and a middle therebetween;
   c) injecting steam into one or more injection points between said toe end and said heel end; and
   d) simultaneously producing mobilized heavy oil;
   e) wherein said method produces more oil at a time point than a similar SW-SAGD well with steam injection only at said toe.

2) The method of claim 1, wherein each injection point is separated from a production segment by at least two thermal packers.

3) The method of claim 1, wherein an injection point is at said middle.

4) The method of claim 1, wherein two injection points are at about ¼ and ¾ of a horizontal length of said well.

5) The method of claim 1, wherein injected steam includes solvent.

6) The method of claim 1, wherein said method includes a preheating phase wherein steam is injected along the entire length of the well.

7) The method of claim 1, wherein said method includes a cyclic preheating phase comprising a steam injection period along the entire length of the well followed by a soaking period.

8) The method of claim 7, including two cyclic preheating phases.

9) The method of claim 7, including three cyclic preheating phases.

10) The method of claim 1, wherein said method includes a preheating phase comprising a steam injection in both the injection segment and the production segment followed by a soaking period.

11) The method of claim 10, including two cyclic preheating phases.

12) The method of claim 10, including three cyclic preheating phases.

13) The method of claim 7, wherein said soaking period is 10-30 days.

14) The method of claim 7, wherein said soaking period is 20 days.

15) A well configuration for producing heavy oils from a reservoir by single well steam and gravity drainage (SW-SAGD), comprising:
   a) a horizontal well in a subsurface reservoir;
   b) said horizontal well having a toe end and a heel end and having at least three segments comprising:
      i) at least two production segments bracketing at least one injection segment;
      ii) said production segments fitted for production; and
      iii) said injection segments fitted for injection.

16) The well configuration of claim 15, wherein thermal packers separate said injection segments and said production segments.

17) The well configuration of claim 15, comprising two injection segments bracketed by production segments.

18) The well configuration of claim 16, wherein said two injection segments are at about ¼ and ¾ of an overall well length.

19) The well configuration of claim 17, said at least two injection segments fitted with coiled tubing having two orifices to inject steam into said two injection segments.

20) The well configuration of claim 15, comprising three injection segments bracketed by production segments.

21) An improved method of producing heavy oils from a SW-SAGD, wherein steam is injected into a toe end of a horizontal well to mobilize oil which is simultaneously produced at a heel end of said horizontal well, the improvement comprising providing one or more injection points for steam between said heel end and said toe end during a production phase, thus improving a CSOR of said horizontal well at a time period as compared to a similar well with steam injection only at said toe end during said production phase.

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