A non-cemented liner (20) is introduced into an injection bore (21), steam is fed into the liner at a first bore part (24) and injected into the reservoir through holes (22, 23) in the liner distributed so that the total hole area per length unit of the liner is greater at a second part (25) than at the first part of the bore. Steam enters an annular space between liner and bore only through holes near first part of the bore and subsequently gradually travels inside the liner in direction of second bore part and gradually enters the annular space through holes nearer and nearer second bore part. Gradually liquid is displaced away from an upper liner part and an upper part of the annular space, so that steam contacts the bore along substantially the entire length of the liner in the upper part of the annular space.
A method of producing viscous hydrocarbons by steam-assisted gravity drainage

The present invention relates to a method of producing viscous hydrocarbons by steam-assisted gravity drainage (SAGD), whereby steam is injected into a hydrocarbon reservoir by means of an injection well bore placed above a production well bore, so that heat is transferred from the steam to the reservoir fluids and thereby reduces the viscosity of hydrocarbons of the reservoir, thereby facilitating recovery of hydrocarbons by means of the production well bore, whereby a liner is introduced into the injection well bore so that it extends from a first part of the injection well bore to a second part of the injection well bore as a non-cemented liner, and whereby the steam is fed into the liner at the first part of the injection well bore and is injected into the hydrocarbon reservoir through a number of holes formed in a wall of the liner.

Steam injection is a common thermal recovery technique for heavy oils, particularly in Canada, Venezuela, and in Oman. The main idea is that steam injected into the well bore condenses in the reservoir and transfers its heat of vaporization to the reservoir fluids. This results in a dramatic reduction in viscosity of the reservoir oil and makes economic recovery of even extra-heavy oil like bitumen possible.

GB 2 053 328 discloses a thermal method for recovering normally immobile oil from a tar sand deposit, in which two wells are drilled horizontally into the deposit, an upper well for injection of heated fluid and a lower well for production of liquids. The injection well includes a casing having perforations along the horizontal section which are in communication with the tar sand deposit. Thermal communication is established between the wells. The wells are operated such that heated mobilized oil and steam flow without substantially mixing. Oil drains continuously by gravity to the production well where it is recovered.
According to SPE 50429, Society of Petroleum Engineers, some operators in California have tried a different completion strategy where they cement the liner and then perforate the well to provide access to the reservoir through multiple zones. In an attempt to ensure that steam is distributed to all the zones and not just the first zone, a limited-entry technique has been used, implying that the size or area of the perforations has been specifically selected to limit the flow rate into a zone at a given injection pressure. However, as most of the annulus is now covered with cement, this design provides very little access to the reservoir.

According to SPE 97922, Society of Petroleum Engineers, some operators choose a slotted liner for both oil producer and steam injector. A slot can be thought of as a rectangular hole, which does not impose any significant pressure drop. Hence, its purpose is not to divert steam but merely to provide access for the steam to reach the reservoir. Unsurprisingly, most of the heat transfer takes place at the heel of the well bore.

A common problem with the above-mentioned completion techniques is that steam distribution along the injection wells is poor. Uniform development of the steam chamber remains one of the most critical challenges of the SAGD process because of its direct impact on heavy oil recovery. This means that the wells must be short and oil recovery suffers from inadequate transfer of heat from the steam to the heavy oil.

The object of the present invention is to provide improved steam distribution even along very long injection well bores.

In view of this object, an annular space is formed between the liner and the injection well bore in which annular space steam injected through the liner may travel along the outside of the liner and contact the injection well bore along the entire length of the liner, and the holes are distributed so that the
total hole area per length unit of the liner is greater at the second part of the injection well bore than at the first part of the injection well bore and so that, during a start-up phase, initially, the steam enters the annular space only through holes near the first part of the injection well bore, and subsequently the steam gradually travels inside the liner in the direction of the second part of the injection well bore and thereby gradually enters the annular space through holes nearer and nearer the second part of the injection well bore, thereby gradually displacing liquid away from an upper part of the liner and away from an upper part of the annular space, so that, during the start-up phase, finally, steam contacts the injection well bore along at least substantially the entire length of the liner in the upper part of the annular space.

Thereby, it may be ensured that liquid is eventually displaced entirely from even the second part of the injection well bore and at the same time it may be avoided that excessive quantities of steam is injected into the hydrocarbon reservoir at the first part of the injection well bore during the start-up phase, and consequently an improved steam distribution along the length of the injection well bore may eventually be achieved during the entire normal operation phase during which production of hydrocarbon takes place. Consequently, oil recovery may be increased as a result of improved transfer of heat from the steam to the heavy oil over the entire length of the well bore.

In an embodiment, an end opening of the liner located at the second part of the injection well bore is closed or at least substantially closed against the injection well bore, preferably by means of an end cap or the like. Thereby, it may better be ensured that steam exits the liner through the holes as desired. However, the end cap may itself be provided with holes for steam injection or drainage of well bore liquids. The end opening of the liner may alternatively be pressed against the end of the injection well bore, thereby at least substantially closing the end opening.
In an embodiment, steam is introduced into the liner only from the end at the first part of the injection well bore. Due to an improved steam distribution along the length of the injection well bore achieved during the start-up phase, it may be unnecessary to introduce steam from more than one end of the liner even during the entire normal operation phase, whereby complex tubing may be avoided.

In an embodiment, the first part of the injection well bore is the inner part at the heel of the injection well bore, and the second part of the injection well bore is the outer part at the toe of the injection well bore. Thereby, steam may enter the liner at the inner part of the injection well bore, whereby auxiliary tubing inside the liner for the introduction of steam at the outer part of the injection well bore may be avoided.

In an embodiment, the liner includes top holes pointing upwards for diverting the steam into the reservoir and bottom holes pointing downwards in order for condensed water and initial well bore liquids to escape from the liner. Thereby, a better separation between steam and well bore liquids may be achieved.

In an embodiment, the liner is inserted into the injection well bore by connecting a number of liner sections at random angular rotations in relation to each other, and each liner section includes at least one set of at least two holes arranged with a regular spacing in the circumferential direction of the liner section. Thereby, as a large number of liner sections may be connected, it may be ensured that generally, over the length of the liner, some of the holes will point in more or less upward direction, and some of the holes will point in more or less downward direction, so that both steam diversion into the reservoir and drainage of liquids out of the liner may be facilitated.
In a structurally advantageous embodiment, each liner section includes at least one set of two holes arranged with a spacing of approximately 180 degrees in the circumferential direction of the liner section.

In an embodiment, the holes of the at least one set of at least two holes have corresponding or equal cross-sectional area. Thereby, the cross-sectional area of the holes per length unit of the liner for top holes as well as for bottom holes may be well-controlled, even if the holes are pre-drilled before insertion of the liner sections into the injection well bore.

In an embodiment, all the holes included by each set of holes are arranged at the same length position of the liner section. This may further facilitate controlling the cross-sectional area of the holes per length unit of the liner for top holes as well as for bottom holes.

In an embodiment, the total hole area per length unit of the liner gradually increases from the first part of the injection well bore to the second part of the injection well bore. Thereby, an even better improved steam distribution along the length of the injection well bore may be achieved.

In an embodiment, the total hole area per length unit of the liner at a part of the second part of the injection well bore is at least 2 times, preferably at least 3 times and most preferred at least or about 4 times the total hole area per length unit of the liner at a part of the first part of the injection well bore. Thereby, a particular good steam distribution along the length of the injection well bore may be achieved.

In an embodiment, the holes in the liner has a diameter in the interval from about 0.5 mm to about 8 mm, and the distance between holes in the liner at the second part of the injection well bore is less than 12 metres (approximately 40 feet), preferably less than 9 metres (approximately 30 feet) and
most preferred about 7.5 metres (approximately 25 feet), and the distance between holes in the liner at the first part of the injection well bore is more than 24 metres (approximately 80 feet), preferably more than 27 metres (approximately 90 feet) and most preferred about 30 metres (approximately 100 feet). Thereby, an even better steam distribution along the length of the injection well bore may be achieved.

In an embodiment, the liner has a diameter of between about 2.5 cm (approximately 1 inch) to about 18 cm (approximately 7 inches).

In an embodiment, over a length of the liner of not more than 20 metres, preferably not more than 30 metres and most preferred not more than 35 metres, at least one hole is positioned at a top position of the liner, and at least one hole is positioned at a bottom position of the liner. This may further facilitate controlling the cross-sectional area of the holes per length unit of the liner for top holes as well as for bottom holes.

In an embodiment, acid is injected into the hydrocarbon reservoir by means of the injection well bore before that steam is injected into the hydrocarbon reservoir by means of the injection well bore. Thereby, a significant advantage may be obtained, as the acid may generate long wormholes along the reservoir section of the well and thereby subsequently promote improved steam distribution.

The invention will now be explained in more detail below by means of examples of embodiments with reference to the very schematic drawing, in which

Fig. 1 is a side view illustration of a general well configuration for the known steam-assisted gravity drainage recovery technique,

Fig. 2 is an end view of the well configuration shown in Fig. 1,
Fig. 3 illustrates a side view of a prior art SAGD injection well,

Fig. 4 is an illustration including a side view of an SAGD injection well according to the invention at initial conditions prior to steam injection at a point in time, \( t = t_0 \), together with a curve showing viscosity of the oil along the length of the wellbore,

Fig. 5 is an illustration corresponding to that of Fig. 4 illustrating conditions at a point in time, \( t = t_i \).

Fig. 6 is an illustration corresponding to that of Fig. 4 illustrating conditions at a point in time, \( t = t_2 \).

Fig. 7 is an illustration corresponding to that of Fig. 4 illustrating conditions at a point in time, \( t = t_3 \), and

Fig. 8 is an illustration corresponding to that of Fig. 4 illustrating conditions at a point in time, \( t = U \gg t_3 \).

Figs. 1 and 2 generally illustrate the well-known method of steam-assisted gravity drainage, whereby a production well bore 1 is placed just above the contact area 2 between the oil reservoir 3 and the aquifer 4, and an injection well bore 5 is placed above the production well bore 1. The production well bore 1 may be placed for instance 5 to 10 metres above the contact area 2 between the oil reservoir 3 and the aquifer 4. The injection well bore 5 may for instance be placed 4 to 6 metres above the production well bore 1. The steam travels upwards and forms a steam chamber 6, so that heat is transferred to the oil reservoir 3, thereby lowering the oil viscosity. The oil with resulting lowered viscosity can then more easily be produced by the production well bore 1.
Accurate well placement is important for the success of this method. If the wells are too close to the oil-water contact, the oil production well bore will produce more water from the aquifer. On the other hand, if the well bores are positioned higher up in the reservoir, oil below the well bores will not be contacted with the steam and will therefore not be produced.

Fig. 3 illustrates a prior art SAGD injection well bore 7 forming a heel 10 (at the inner part of the bore) and a toe 11 (at outer part of the bore). The heel 10 forms the bend between a vertical part 12 and a horizontal part 13 of the well bore 7. Steam, represented by the arrows, travels down the well bore 7 inside an open-ended tubing 8 and enters an open annulus 9 formed between the tubing 8 and the well bore 7 to contact the reservoir fluids. Most of the heat will be used when steam contacts reservoir fluids at the toe 11 of the well bore 7, and gradually less heat will be available as the steam travels in the annulus 9 back towards the heel 10. Ensuring that steam reaches the heel 10 of the well bore before condensing may limit the current completion length to about 1500 metres. If sufficient displacement of the fluids in the heel 10 of the well bore is not obtained, then the surrounding reservoir volumes will only be heated by conductance from the heated wellbore which reduces the economic value of the recovery project.

The SAGD process generally takes place in three distinct phases: start-up, or circulation; normal SAGD operation; and wind down. The start-up is aimed at mobilizing the heavy oil close to and between the injection well bore 5 and the production well bore 1 to establish communication between the well bores. The most widely used method for start-up is circulating steam in both injection well bore and production well bore for as long as 90 days. Normal operation involves injecting steam and producing heavy oil to form the steam chamber 6 above the pair of well bores. This phase provides access to the maximum amount of resources within the drainage area and lasts as many years as necessary, so that the maximum amount of oil is recovered from the
drainage volume. Finally, the wind down includes a series of operations aimed at reducing the amount of steam injected and using auxiliary operating patterns to maximize recovery.

If the steam condenses before contacting the reservoir 3, the released heat will not lead to the desired oil viscosity reduction; instead it will be absorbed by the tubing steel of the open-ended tubing 8. Effective development of areally extensive reservoirs requires long horizontal well bores, and the ability to deliver steam across the entire reservoir interval is of great importance for economic development of such reservoirs. The uniform distribution of steam is a challenge because of the large mobility contrast between the injected steam and the reservoir fluid having viscosity in the range of 0.1 to 1.0 million cP. Failure to fully displace the open annulus 9 to steam will prevent a uniform SAGD process across the exposed reservoir section and the contrast will grow with time as the injected steam provide even higher mobility in the better exposed areas. Therefore, the prior art SAGD injection well bore 7 illustrated in Fig. 3 may suffer from poor steam distribution along the horizontal part 13 of the well bore 7, in particular if said horizontal part 13 is relatively long.

Figs. 4 to 8 illustrate the start-up phase of the method of producing viscous hydrocarbons by steam-assisted gravity drainage (SAGD) according to the present invention at different time steps.

The method according to the present invention seeks to achieve a controlled steam distribution along the entire well bore length (the length of the injection well bore as well as the length of the production well bore) by means of a non-cemented liner 20 inserted into an injection well bore 21. The wall of the non-cemented liner 20 is provided with a limited number of holes 22, 23 for steam injection from the liner 20 into the reservoir as well as escape of condensed water and the initial wellbore fluids from the liner 20. The holes may
be pre-drilled before insertion of the liner 20 into the well bore. Preferably, the well bore 21 is configured as an open hole completion; however, if special demands may occur, the wall of the bore could be provided with a slotted liner, screen or similar in order to strengthen the bore, but still providing substantially free access to the wall of the bore.

The holes 22, 23 are distributed over the length of the liner 20 so that the total hole area per length unit of the liner 20 is greater at a second part 25 of the injection well bore 21 than at a first part 24 of the injection well bore 21. This may be achieved either by providing holes regularly along the length of the liner, but larger holes at the second part 25 than at the first part 24, or by providing holes of equal size along the liner, but more holes per length unit of the liner 20 at the second part 25 than at the first part 24. The latter configuration is the one that is illustrated in Figs. 4 to 8. Furthermore, a combination of these configurations is possible. It may be preferred that the total hole area per length unit of the liner gradually increases from the first part 24 of the injection well bore 21 to the second part 25 of the injection well bore 21.

The holes 22, 23 may be drilled in pairs of two, whereby a top hole 22 pointing upwards serves to divert the steam by imposing a pressure drop whereby a choke effect is created, and whereby a bottom hole 23 drilled oppositely and pointing downwards serves to enable condensed water and initial well bore fluids to escape from the liner 20 into the reservoir. However, although the figures illustrate holes 22, 23 only at the top and bottom positions of the liner 20, holes may also be positioned at other positions. Preferably, at least some of the holes 22, 23 are positioned at the top position of the liner 20, and, preferably, at least some of the holes are positioned at the bottom position of the liner 20. Furthermore, this should preferably be the case over a reasonable length of the liner, for instance such as 30 metres, in order to ensure regular steam diversion to the top of the injection well bore along the
length of the bore as well as regular drainage of the bottom of the liner 20 along the length of the bore.

The liner 20 is preferably inserted into the newly drilled injection well bore 21 by connecting a number of liner sections at random angular rotations in relation to each other. Each liner section may include at least one set of at least two pre-drilled holes arranged with a regular spacing in the circumferential direction of the liner section. Thereby, it may generally be ensured that, over a certain length of the liner, at least some holes will be positioned more or less at the top position of the liner, and that, over a certain length of the liner, at least some holes will be positioned more or less at the bottom position of the liner.

In order to control the distribution of the hole area per length unit of the injection liner, both for top holes 22 directed upwards and intended for steam diversion and for bottom holes 23 directed downwards and intended for drainage, it may in the case of pre-drilled holes be preferred that the holes are arranged in sets of holes positioned at the same length position of the liner 20, whereby all holes of a set have corresponding cross-sectional area.

On the other hand, if the holes 22, 23 would be drilled after insertion of the liner 20 into the injection well bore 21, all of the holes 22 could just as well be drilled at least substantially at a top position of the liner 20, and similarly, all of the holes 23 could just as well be drilled at least substantially at a bottom position of the liner 20. Furthermore, in this case, top holes 22 and bottom holes 23 could have different cross-sectional area.

Fig. 4 illustrates an SAGD injection well bore 21 according to the present invention at a point in time, \( t = t_0 \). The injection well bore 21 may be arranged in an oil reservoir above a production well bore in the same way as the injection well bore 5 illustrated in Figs. 1 and 2. The injection well bore 21 is in Fig. 4
shown at initial conditions prior to steam injection, whereby the injection well bore 21 is filled with liquids from the drilling process with a temperature approximately equal to the reservoir temperature. The upper circles symbolize the top holes 22 to be used for steam to exit the liner 20, whereas the lower circles represent bottom holes 23 to be used by the condensed water as well as the initial wellbore fluids.

In Figs. 4 to 8, the curve shown below the injection well bore 21 illustrates the viscosity, $\mu_{oil}$, of the oil in the immediate vicinity of the injection well bore 21 as a function of the length along the well bore, L, measured from a first end 29 of the injection well bore 21 in the direction of a second end 30 of the injection well bore 21. The first end 29 of the injection well bore 21 is located at the first part 24 of the injection well bore 21, and the second end 30 of the injection well bore 21 is located at the second part 25 of the injection well bore 21. Dotted parts of the curve illustrate the oil viscosity from the previous time step shown in the previous figure.

It is noted that the first end 29 of the substantially horizontal injection well bore 21 is connected to a not shown substantially vertical well bore leading to the surface of the reservoir, corresponding to the prior art arrangement illustrated in Fig. 3. Thereby, a heel of the well bore is formed at the the first end 29, and the first part 24 of the injection well bore 21 forms the inner part and the second part 25 forms the outer part. According to the present invention, steam is preferably introduced into the liner 20 at the first end 29 of the well bore, however, by means of auxiliary tubing inside the liner 20 leading from the heel at the first part 24 to the second part 25, steam could in fact be introduced at the second end 30 of the injection well bore instead of at the first end 29.

It is noted that in Figs. 5 to 8, the direction of the flow of steam is illustrated by means of arrows.
Fig. 5 depicts a snapshot in time during the start-up of the injection well bore 21 at a point in time, \( t = t_1 \). The steam (illustrated by less dense hatching) has travelled a certain distance into the liner from the first end 29 of the injection well bore 21 and into the first part 24 of the injection well bore 21. Due to a small hole size, a significant pressure drop is imposed across each hole, and critical flow governed by the speed of sound may develop across the hole. Therefore, regardless of possibly increased pump pressure, the same amount of flow will pass through the hole to an annular space 26 is formed between the liner 20 and the injection well bore 21. The remainder of the steam will stay inside the liner 20 and displace the liquid well bore fluids (illustrated by dense hatching) further towards an end 27 of the liner at the second part 25 of the injection well bore 21, whereby it exits the liner 20 out through the top holes 22 further towards the end 27 and out through the bottom holes 23 along the entire length of the injection well bore 21. A certain amount of steam will condense inside the well bore; this condensed water will also escape into the reservoir primarily through the bottom holes 23.

The oil viscosity in the near well bore region will decrease in the area contacted by the steam as the steam transfers its latent heat of vaporization to the heavy oil.

In Figs. 6 and 7, the steam front has moved further down the liner 20 towards the end 27. The portion of steam which has entered the annular space 26 through the top holes 22 will propagate into the reservoir, but some of the steam will displace the liquids from the top to the bottom of the annular space 26. Therefore, with time, the top of the annular space 26 will be filled with steam, whereas the bottom of the annular space 26 will be filled with condensed water.

After sufficient time, as illustrated in Fig. 8, an equilibrium situation has been established. The original well bore fluids have been fully displaced from the
liner 20, but two-phase flow will prevail; steam, with gas-phase properties will
occupy the top part of the cross-sectional area of the line 20, whereas condensing vapor, with liquid-like properties will occupy the bottom of the liner 20, exiting the liner through the bottom holes 23 at a rate equal to the condensation rate. By now, the heat profile along the well may be as uniform as it can be and the oil viscosity near the well bore has been significantly reduced.

The steam distribution along the liner during the start-up phase as illustrated in Figs. 4 to 8 is a result of the above-described distribution of the total hole area per length unit of the liner 20 and may be fine-tuned by adjusting the rate with which the total hole area per length unit is increased along the length of the liner 20. For instance, the holes 22, 23 in the liner 20 may have a diameter in the interval from about 0.5 mm to about 8 mm, and the distance between holes 22, 23 in the liner 20 at the second part 25 of the injection well bore 21 may be less than 12 metres (approximately 40 feet), preferably less than 9 metres (approximately 30 feet) and most preferred about 7.5 metres (approximately 25 feet), and the distance between holes 22, 23 in the liner 20 at the first part 24 of the injection well bore 21 is more than 24 metres (approximately 80 feet), preferably more than 27 metres (approximately 90 feet) and most preferred about 30 metres (approximately 100 feet). Thereby, the holes may have a constant diameter over the entire length of the liner 20 and the spacing between the holes in the longitudinal direction of the liner may vary. Alternatively, the diameter of the holes may vary over the length of the liner 20 and the spacing between the holes in the longitudinal direction of the liner may be constant. It is even possibly that both the diameter of the holes and said spacing between the holes vary over the length of the liner 20. In any case, the hole diameter and the spacing between holes may be adjusted so that the total hole area per length unit of the liner at a part of the second part 25 of the injection well bore 21 may be at least 2 times, preferably at least 3 times and most preferred at least or about 4 times the total hole area.
per length unit of the liner at a part of the first part 24 of the injection well bore 21.

The liner 20 may typically have a diameter of between about 2.5 cm (approximately 1 inch) to about 18 cm (approximately 7 inches). For instance, coiled tubing may be used, and for instance of a diameter of approximately 4.4 cm (1.75 inches).

An average hole area per length unit of the liner may be about 2.0 mm²/m for a length of the liner of approximately 1000 metres. For a longer liner, the average hole area per length unit of the liner may be smaller, probably around 0.5-1.0 mm²/m.

The hole area per length unit of the liner may be from 60-70 % of the average hole area per length unit of the liner at the heel (inner part) of the well to 130-140% of said average hole area at the toe (outer part) of the well. Regarding the length of the wells allowed by means of the invention, an increase from about 1,000 metres to some 2,000 - 3,000 metres per well is envisaged.

The above-described distribution of the total hole area pr. length unit of the liner 20 in fact results in that, during a start-up phase, initially, the steam enters the annular space 26 only through holes 22 near the first part 24 of the injection well bore 21, and subsequently the steam gradually travels inside the liner 20 in the direction of the second part 25 of the injection well bore 21 and thereby gradually enters the annular space 26 through holes 22 nearer and nearer the second part 25 of the injection well bore 21, thereby gradually displacing liquid away from an upper part of the liner 20 and away from an upper part of the annular space 26, so that, during the start-up phase, finally, steam contacts the injection well bore 21 along at least substantially the entire length of the liner 20 in the upper part of the annular space 26.
An end opening of the liner 20 located at the second part 25 of the injection well bore 21 is preferably closed against the injection well bore 21 by means of an end cap 28 or the like. The end cap 28 could be provided with upper and/or lower holes for steam injection.

According to the present invention, it is preferred that steam is introduced into the liner 20 only from the first end 29 at the first part 24 of the injection well bore 21, at least during the start-up phase. However, at least during the entire normal operation phase, steam could possibly also be introduced from the second end 30 of the injection well bore 21.

Acid may be injected into the hydrocarbon reservoir by means of the injection well bore 21 before that steam is injected into the hydrocarbon reservoir by means of the injection well bore 21. Thereby, a significant advantage may be obtained, as the acid may generate long wormholes along the reservoir section of the well and thereby subsequently promote improved steam distribution.
Claims

1. A method of producing viscous hydrocarbons by steam-assisted gravity drainage (SAGD), whereby steam is injected into a hydrocarbon reservoir by means of an injection well bore (21) placed above a production well bore, so that heat is transferred from the steam to the reservoir fluids and thereby reduces the viscosity of hydrocarbons of the reservoir, thereby facilitating recovery of hydrocarbons by means of the production well bore, whereby a liner (20) is introduced into the injection well bore (21) so that it extends from a first part (24) of the injection well bore to a second part (25) of the injection well bore as a non-cemented liner, and whereby the steam is fed into the liner (20) at the first part (24) of the injection well bore (21) and is injected into the hydrocarbon reservoir through a number of holes (22, 23) formed in a wall of the liner (20), characterised by that an annular space (26) is formed between the liner (20) and the injection well bore (21) in which annular space (26) steam injected through the liner (20) may travel along the outside of the liner and contact the injection well bore (21) along the entire length of the liner (20), and by that the holes (22, 23) are distributed so that the total hole area per length unit of the liner (20) is greater at the second part (25) of the injection well bore (21) than at the first part (24) of the injection well bore (21) and so that, during a start-up phase, initially, the steam enters the annular space (26) only through holes (22) near the first part (24) of the injection well bore (21), and subsequently the steam gradually travels inside the liner (20) in the direction of the second part (25) of the injection well bore (21) and thereby gradually enters the annular space (26) through holes (22) nearer and nearer the second part (25) of the injection well bore (21), thereby gradually displacing liquid away from an upper part of the liner (20) and away from an upper part of the annular space (26), so that, during the start-up phase, finally, steam contacts the injection well bore (21) along at least substantially the entire length of the liner (20) in the upper part of the annular space (26).
2. A method according to claim 1, whereby an end opening of the liner (20) located at the second part (25) of the injection well bore (21) is closed or at least substantially closed against the injection well bore, preferably by means of an end cap (28) or the like.

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3. A method according to claim 1 or 2, whereby steam is introduced into the liner (20) only from the end at the first part (24) of the injection well bore (21).

4. A method according to any one of the preceding claims, whereby the first part (24) of the injection well bore (21) is the inner part at the heel of the injection well bore (21), and whereby the second part (25) of the injection well bore (21) is the outer part at the toe of the injection well bore (21).

5. A method according to any one of the preceding claims, whereby the liner (20) includes top holes (22) pointing upwards for diverting the steam into the reservoir and bottom holes (23) pointing downwards in order for condensed water and initial well bore fluids to escape from the liner (20).

6. A method according to any one of the preceding claims, whereby the liner (20) is inserted into the injection well bore (21) by connecting a number of liner sections at random angular rotation in relation to each other, and whereby each liner section includes at least one set of at least two holes (22, 23) arranged with a regular spacing in the circumferential direction of the liner section.

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7. A method according to claim 6, whereby each liner section includes at least one set of two holes (22, 23) arranged with a spacing of approximately 180 degrees in the circumferential direction of the liner section.
8. A method according to claim 6 or 7, whereby the holes (22, 23) of the at least one set of at least two holes have corresponding or equal cross-sectional area.

9. A method according to any one of the claims 6 to 8, whereby all the holes included by each set of holes (22, 23) are arranged at the same length position of the liner section.

10. A method according to any one of the preceding claims, whereby the total hole area per length unit of the liner gradually increases from the first part (24) of the injection well bore (21) to the second part (25) of the injection well bore (21).

11. A method according to any one of the preceding claims, whereby the total hole area per length unit of the liner at a part of the second part (25) of the injection well bore (21) is at least 2 times, preferably at least 3 times and most preferred at least or about 4 times the total hole area per length unit of the liner at a part of the first part (24) of the injection well bore (21).

12. A method according to any one of the preceding claims, whereby the holes (22, 23) in the liner (20) has a diameter in the interval from about 0.5 mm to about 8 mm, and whereby the distance between holes (22, 23) in the liner (20) at the second part (25) of the injection well bore (21) is less than 12 metres (approximately 40 feet), preferably less than 9 metres (approximately 30 feet) and most preferred about 7.5 metres (approximately 25 feet), and the distance between holes (22, 23) in the liner (20) at the first part (24) of the injection well bore (21) is more than 24 metres (approximately 80 feet), preferably more than 27 metres (approximately 90 feet) and most preferred about 30 metres (approximately 100 feet).
13. A method according to any one of the preceding claims, whereby the liner (20) has a diameter of between about 2.5 cm (approximately 1 inch) to about 18 cm (approximately 7 inches).

14. A method according to any one of the preceding claims, whereby, over a length of the liner (20) of not more than 20 metres, preferably not more than 30 metres and most preferred not more than 35 metres, at least one hole (22) is positioned at a top position of the liner (20), and at least one hole (23) is positioned at a bottom position of the liner (20).

15. A method according to any one of the preceding claims, whereby acid is injected into the hydrocarbon reservoir by means of the injection well bore (21) before that steam is injected into the hydrocarbon reservoir by means of the injection well bore (21)
Fig. 4

Fig. 5
Fig. 8
INTERNATIONAL SEARCH REPORT

A. CLASSIFICATION OF SUBJECT MATTER

INV. E21B43/24
ADD.

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

EPO-Internal, WPI Data

C. DOCUMENTS CONSIDERED TO BE RELEVANT

<table>
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<tr>
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<th>Citation of document, with indication, where appropriate, of the relevant passages</th>
<th>Relevant to claim No.</th>
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[X] Further documents are listed in the continuation of Box C. [X] See patent family annex.

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Authorized officer: Hustedt, Bernhard

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