Office de la Propriété Intellectuelle du Canada
Un organisme d'Industrie Canada

Canadian Intellectual Property Office
An agency of Industry Canada

CA 2778135 C 2014/04/08

(11)(21) 2 778 135

(12) BREVET CANADIEN
CANADIAN PATENT

(13) C

(22) Date de dépôt/Filing Date: 2012/05/18

(41) Mise à la disp. pub./Open to Public Insp.: 2012/11/20

(45) Date de délivrance/Issue Date: 2014/04/08

(30) Priorité/Priority: 2011/05/20 (CA2.740.941)

(51) Cl.Int./Int.Cl. *E21B 43/241* (2006.01), *E21B 43/22* (2006.01), *E21B 43/24* (2006.01), *E21B 43/30* (2006.01)

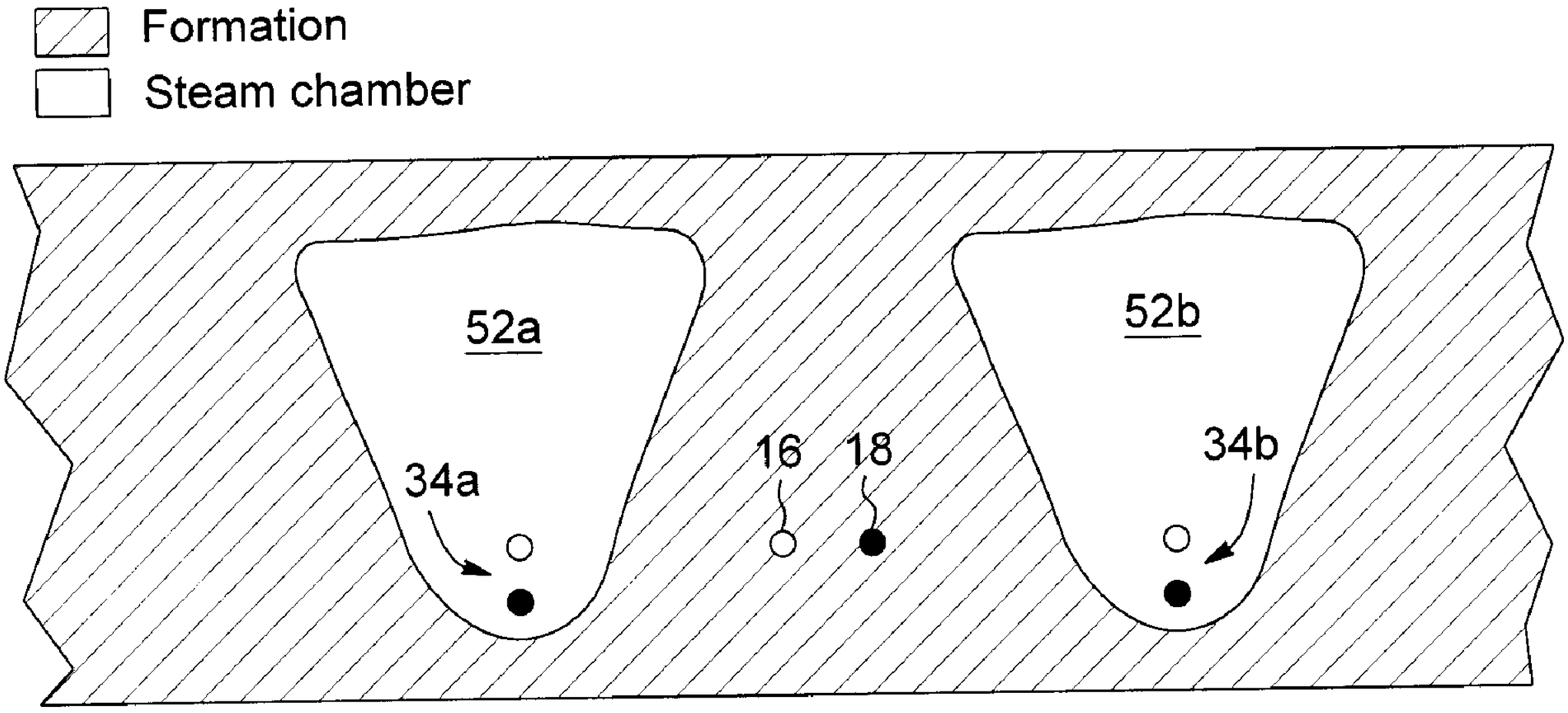
(72) Inventeurs/Inventors:
RAFFA, DUILIO FEDERICO, CA;
CUTHIELL, DAVID LAYTON, CA

(73) Propriétaire/Owner:
SUNCOR ENERGY INC., CA

(74) Agent: ROBIC

(54) Titre : TECHNIQUES DE DEMARRAGE A L'AIDE DE SOLVANT POUR LA RECUPERATION IN SITU DE BITUME DANS LES PUITS SAGD, LES PUITS DE REMPLISSAGE ET LES PUITS D'EXTENSION

(54) Title: SOLVENT ASSISTED STARTUP TECHNIQUES FOR IN SITU BITUMEN RECOVERY WITH SAGD WELL PAIRS, INFILL WELLS OR STEP-OUT WELLS



(57) Abrégé/Abstract:
An in situ bitumen recovery startup process can include injecting a solvent containing startup fluid into a first horizontal well, providing a pressure sink in a second horizontal well for pressure drive of the solvent toward the second well to mobilize the interwell region, and establishing fluid communication between the first horizontal well and the second horizontal well. Other startup processes can include selecting startup intervals along the wells and, for each interval, isolating the interval and injecting solvent at the interval location to enhance mobility. The processes may be applied to SAGD well pairs as well as infill wells, step-out wells and/or multilateral wells.

ABSTRACT

An in situ bitumen recovery startup process can include injecting a solvent containing startup fluid into a first horizontal well, providing a pressure sink in a second horizontal well for pressure drive of the solvent toward the second well to mobilize the interwell region, and establishing fluid communication between the first horizontal well and the second horizontal well. Other startup processes can include selecting startup intervals along the wells and, for each interval, isolating the interval and injecting solvent at the interval location to enhance mobility. The processes may be applied to SAGD well pairs as well as infill wells, step-out wells and/or multilateral wells.

SOLVENT ASSISTED STARTUP TECHNIQUES FOR IN SITU BITUMEN RECOVERY WITH SAGD WELL PAIRS, INFILL WELLS OR STEP-OUT WELLS

FIELD OF THE INVENTION

The present invention generally relates to the field of in situ bitumen recovery and in particular relates to techniques for solvent assisted startup for SAGD well pairs, infill wells and/or step-out wells.

BACKGROUND

There are a number of in situ techniques for recovering bitumen from subsurface reservoirs. One technique called Steam Assisted Gravity Drainage (SAGD) has become a widespread process of recovering heavy oil and bitumen particularly in the oil sands of northern Alberta. The SAGD process involves well pairs each of which consists of two horizontal wells drilled in the oil sands and aligned in spaced relation one on top of the other. The upper well is a steam injection well and the lower well is a producer well. The injected steam forms a steam chamber that grows upward and outward within the formation, heating the bitumen or crude oil sufficiently to reduce its viscosity and allow it to flow toward the producer well along with condensed water.

Numerous SAGD well pairs are usually provided in groups extending from central pads for hundreds of meters. The well pairs of a group often extend parallel generally parallel to one another.

Once a SAGD well pair is drilled and completed, the first phase of SAGD operations is the so-called startup phase. In the startup phase, fluid communication is established between the injection and producer wells of a given well pair. Prior to startup, the high saturation bitumen interval separating the injection and production wells of each pair has low fluid mobility and the SAGD process relies on initially establishing a heated mobile interval in between the injection and production wells. It is important for an effective SAGD operation to reduce the viscosity of the bitumen between injection and production wells and produce it. This procedure, establishing heat communication between two wells at the initial stages of SAGD, can be done by circulating steam into both injection and production wells. The wells act as hot fingers in the reservoir and heating is by conduction. When initial steam

injectivity is possible, steam may be injected in the top well and production obtained from the bottom well. After the pre-heat period the displacement and production of the bitumen in the region between wells is the step responsible for the initiation of the steam chamber.

However, heat conduction is generally a slow process. Pre-heat of SAGD wells takes between three and six months.

Solvent injection for SAGD startup and initialization has been attempted with limited success. In particular, it has been proposed to provide solvent via the injection and production wells and to allow a solvent soak period to reduce the viscosity of the bitumen in between the injection and production wells. However, this technique has a number of drawbacks, including slow solvent penetration and consistency along the well pair. Solvent soaking relies on diffusion which is a slow process.

A solvent pre-soak process includes the injection of solvent in advance to the usual pre-heating process. The time between the injection of solvent and the circulation of steam allows the solvent to slowly diffuse and mix with the bitumen lowering its viscosity. Solvent pre-soak leads to mobile water displacement and creation of a halo of solvent surrounding each well. Due to vertical-horizontal permeability contrast, the lateral expansion of the halo is often encouraged. It follows that to be able to deliver solvent to the whole bitumen volume between a well pair a large volume of solvent is necessary.

The known processes for in situ recovery operations startup, such as for SAGD, have a variety of disadvantages.

SUMMARY OF THE INVENTION

The present invention provides techniques for solvent assisted startup for in situ recovery of bitumen.

In some optional implementations, there is an in situ bitumen recovery startup process, including:

injecting a solvent-containing startup fluid into a first horizontal well located in a bitumen-containing reservoir, where the fluid is injected below a fracturing pressure of the reservoir proximate the first horizontal well;

providing a pressure sink in a second horizontal well located adjacent to the first well to define an interwell region there-between, to promote pressure drive of the solvent from the first horizontal well toward the second horizontal well to mobilize bitumen in the interwell region; and

establishing fluid communication between the first horizontal well and the second horizontal well.

In some optional implementations, the pressure sink is created by a pump associated with the second horizontal well for producing fluids therefrom.

In some optional implementations, the solvent containing startup fluid contains a solvent selected from aromatic compounds and alkanes.

In some optional implementations, the solvent in the solvent containing startup fluid comprises at least one of toluene, xylene, diesel, butane, pentane, hexane, heptane and naphtha.

In some optional implementations, the solvent in the solvent containing startup fluid comprises naphtha.

In some optional implementations, the solvent in the solvent containing startup fluid consists of naphtha.

In some optional implementations, the solvent containing startup fluid further comprises water.

In some optional implementations, the process includes:

producing fluids from the second horizontal well; and

halting the injection and the production upon reaching an upper solvent concentration threshold in produced fluid.

In some optional implementations, the step of producing fluids from the second horizontal well comprises operating so that the produced fluid comprises between about 20% and about 50% volume of solvent based on the total volume of bitumen and solvent mixture.

In some optional implementations, the upper solvent concentration threshold is approximately 50% volume based on the total volume of the bitumen and solvent mixture.

In some optional implementations, the solvent is selected to avoid asphaltene deposition.

In some optional implementations, the solvent containing startup fluid is formulated to avoid asphaltene deposition.

In some optional implementations, the solvent containing startup fluid is injected at a temperature between an initial reservoir temperature and about 150ºC.

In some optional implementations, the solvent containing startup fluid is injected at a temperature above 100ºC.

In some optional implementations, the solvent containing startup fluid is injected at a pressure between about initial reservoir pressure and about 100 kPa below the fracturing pressure of the reservoir proximate the injection well.

In some optional implementations, the interwell region is about 3 m to about 10m.

In some optional implementations, the interwell region is about 4 to 7 m.

In some optional implementations, the process includes:

(i) isolating a first horizontal startup interval of the well pair;

(ii) injecting the solvent containing startup fluid into the first well at the first horizontal startup interval;

(iii) providing the pressure sink in the second well to promote pressure drive of the solvent from the first well toward the second well at the first horizontal startup interval, to mobilize bitumen in a first portion of the interwell region;

(iv) establishing fluid communication between the first well and the second well in the first portion of the interwell region;

(v) halting solvent injection and production in the first horizontal startup interval; and

(vi) isolating additional horizontal startup intervals one-by-one and repeating steps (ii) to (v) for each of the additional horizontal startup intervals.

In some optional implementations, the isolating is performed using packers.

In some optional implementations, the isolating is performed using at least one diverter.

In some optional implementations, the isolating is performed using balls and/or sliding sleeves.

In some optional implementations, the injecting of the solvent containing startup fluid is only done via the first well.

In some optional implementations, the providing the pressure sink is done only in the second well.

In some optional implementations, the first well is a SAGD injection well and the second well is a SAGD production well, forming a well pair.

In some optional implementations, the first well is a first step-out well and the second well is a second step-out well, both being provided in a recovery zone of the reservoir in spaced relation with respect to an adjacent SAGD steam chamber.

In some optional implementations, the first step-out well is further away from the SAGD steam chamber than the second step-out well.

In some optional implementations, the first and second step-out wells are located at approximately the same depth as each other.

In some optional implementations, the first and second step-out wells are located at approximately the same depth as an adjacent SAGD well pair.

In some optional implementations, the first well is a first infill well and the second well is a second infill well, both being provided in a residual zone, the residual zone being defined in between two flanking SAGD steam chambers.

In some optional implementations, the first and second infill wells are operated in startup mode prior to coalescence of the two flanking SAGD steam chambers along the length of the first and second infill wells.

In some optional implementations, the process further includes operating a third infill well in the residual zone as a solvent injection well or a pressure sink well.

In some optional implementations, there is an in situ bitumen recovery startup process for a well in a bitumen containing reservoir, the well being approximately parallel to one or more adjacent SAGD steam chambers, the process including:

selecting a plurality of startup intervals along a length of the well;

for each of the plurality of startup intervals:

isolating the startup interval;

injecting a solvent-containing startup fluid into the startup interval; wherein the injected startup fluid penetrates the reservoir and mobilizes bitumen in a region proximate the interval;

ceasing solvent injection into the startup interval; and

establishing fluid communication with at least one adjacent SAGD chamber; and

producing bitumen from the well.

In some optional implementations, the process further includes selecting one or more of the startup intervals based on a distance from the well within the selected startup interval to the one or more adjacent SAGD steam chambers.

In some optional implementations, the process further includes selecting one or more of the startup intervals based on a distance based on a temperature of the reservoir around the selected startup interval.

In some optional implementations, the well is a step-out well provided in a recovery zone of the reservoir in spaced relation with respect to one adjacent SAGD steam chamber.

In some optional implementations, at least one of the startup intervals is selected to inject the solvent-containing startup fluid into a surrounding region that is at initial reservoir temperature.

In some optional implementations, at least one of the startup intervals is selected to inject the solvent-containing startup fluid into a surrounding region that is colder than other intervals of the step-out well.

In some optional implementations, at least one of the startup intervals is selected to inject the solvent-containing startup fluid into a surrounding region that is further away from the adjacent SAGD steam chamber than other intervals of the step-out well.

In some optional implementations, the process further includes injecting the solvent containing startup fluid through a selected startup interval into a surrounding region of the reservoir in a greater amount, for a greater duration and/or at an earlier injection time, based on the temperature of the surrounding region and/or a distance from the well within the selected startup interval to the adjacent SAGD steam chamber.

In some optional implementations, the injecting of the greater amount, for the greater duration and/or at the earlier injection time is performed where the surrounding region of the selected startup interval is at initial reservoir temperature and/or is colder than other intervals of the well.

In some optional implementations, the injecting of the greater amount, for the greater duration and/or at the earlier injection time is performed where the distance from the well within the selected startup interval to the adjacent SAGD steam chamber is greater than other intervals of the well.

In some optional implementations, the well is an infill well provided in a residual zone, the residual zone being defined in between two flanking SAGD steam chambers.

In some optional implementations, at least one of the startup intervals is selected to inject the solvent containing startup fluid into a surrounding region that is at initial reservoir temperature.

In some optional implementations, at least one of the startup intervals is selected to inject the solvent containing startup fluid into a surrounding region that is colder than other intervals of the infill well.

In some optional implementations, at least one of the startup intervals is selected to inject the solvent containing startup fluid into a surrounding region that is further away from the flanking SAGD steam chambers than other intervals of the infill well.

In some optional implementations, the process includes injecting the solvent containing startup fluid through a selected startup interval into a surrounding region of the reservoir in a greater amount, for a greater duration and/or at an earlier injection time, based on the temperature of the surrounding region, a distance from the well within the selected startup interval to the flanking SAGD steam chambers, and/or whether the flanking SAGD steam chambers have coalesced above the selected startup interval.

In some optional implementations, the injecting of the greater amount, for the greater duration and/or at the earlier injection time is performed where the surrounding region of the selected startup interval is at initial reservoir temperature and/or is colder than other intervals of the well.

In some optional implementations, the injecting of the greater amount, for the greater duration and/or at the earlier injection time is performed where the distance from the well within the selected startup interval to the adjacent SAGD steam chamber is greater than other intervals of the well.

In some optional implementations, the injecting of the greater amount, for the greater duration and/or at the earlier injection time is performed wherein where the flanking SAGD steam chambers have not yet coalesced above the selected startup interval.

In some optional implementations, the isolating is performed by packers, by at least one diverter, using balls and/or sliding sleeves.

In some optional implementations, the startup intervals are sized to have lengths in accordance with well conformance.

In some optional implementations, the startup intervals are sized to have lengths of at most about 100 m.

In some optional implementations, the solvent containing startup fluid contains a solvent selected from aromatic compounds and alkanes.

In some optional implementations, the solvent in the solvent containing startup fluid comprises at least one of toluene, xylene, diesel, butane, pentane, hexane, heptane and naphtha.

In some optional implementations, the solvent in the solvent containing startup fluid comprises naphtha.

In some optional implementations, the solvent in the solvent containing startup fluid consists of naphtha.

In some optional implementations, the solvent containing startup fluid further comprises water.

In some optional implementations, the solvent containing startup fluid is formulated to avoid asphaltene deposition.

In some optional implementations, the solvent-containing startup fluid is injected at a temperature between the initial reservoir temperature 8 and about 150°C.

In some optional implementations, the solvent-containing startup fluid is injected at a temperature above 100°C.

In some optional implementations, the solvent-containing startup fluid is injected at a pressure between about initial reservoir pressure and about 100 kPa below the fracturing pressure of the reservoir proximate the well.

In some optional implementations, the well is a multilateral well as described herein.

In some optional implementations, there is an in situ bitumen recovery startup process for a well selected from an infill well and a step-out well located adjacent to at least one SAGD steam chamber, the process comprising:

injection of a solvent-containing startup fluid into the well, wherein:

the injection is commenced when a surrounding region contiguous with the well is still unheated by heat from the at least one SAGD steam chamber;

the injected solvent-containing startup fluid penetrates the surrounding region and mobilizes bitumen therein, thereby forming a solvent mobilized zone in the surrounding region; and

the injection is performed to establish fluid communication between the at least one SAGD steam chamber and the solvent mobilized zone; and

operating the well in production mode for bitumen recovery.

In some optional implementations, the injection of the solvent-containing startup fluid is performed along the entire length of the well.

In some optional implementations, the injection of the solvent-containing startup fluid comprises injecting into at least one isolated section of the well in order to form the solvent mobilized zone around the at least one isolated section.

In some optional implementations, the at least one isolated section comprises a plurality of isolated sections, and the injection of the solvent-containing startup fluid comprises injecting into the plurality of isolated sections of the well in order to form corresponding solvent mobilized zones around respective isolated sections.

In some optional implementations, the at least one isolated section of the well is selected in order to provide enhanced conformance of production along the well.

In some optional implementations, the at least one isolated section of the well is selected to inject the solvent-containing startup fluid into a surrounding first region that is colder and/or further away from the at least one adjacent SAGD steam chamber than other sections of the well.

In some optional implementations, the well is a multilateral well as described herein.

In some optional implementations, there is an in situ bitumen recovery startup process for an infill well located in a residual zone defined between two flanking SAGD steam chambers, the process comprising:

injection of a solvent-containing startup fluid into the well, wherein:

the injection is commenced prior to coalescence of the two flanking SAGD steam chambers along the length of the infill well;

the injected solvent-containing startup fluid penetrates the reservoir and mobilizes bitumen therein, thereby forming a solvent mobilized zone; and

the injection is performed to accelerate advancement of the at least one flanking SAGD steam chamber toward the infill well through the solvent diluted zone and establish fluid communication between the at least one SAGD steam chamber and the solvent mobilized zone; and

operating the infill well in production mode for bitumen recovery from the residual zone.

In some optional implementations, the injection of the solvent-containing startup fluid is performed along the entire length of the infill well.

In some optional implementations, the injection of the solvent-containing startup fluid comprises injecting into at least one isolated section of the infill well in order to form the solvent mobilized zone around the at least one isolated section, wherein the injection into the at least one isolated section is commenced prior to coalescence of the two flanking SAGD steam chambers along a length corresponding to the at least one isolated section.

In some optional implementations, the at least one isolated section comprises a plurality of isolated sections, and the injection of the solvent-containing startup fluid comprises injecting into the plurality of isolated sections of the infill well in order to form corresponding solvent mobilized zones around respective isolated sections, wherein the injection into each of the isolated sections is commenced prior to coalescence of the two flanking SAGD steam chambers along respective lengths corresponding to the isolated sections.

In some optional implementations, the at least one isolated section of the infill well is selected in order to provide enhanced conformance of production along the infill well.

In some optional implementations, the at least one isolated section of the infill well is further selected to inject the solvent-containing startup fluid into a surrounding first region that is colder and/or further away from the at least one adjacent SAGD steam chamber than other sections of the infill well.

In some optional implementations, the infill well is a multilateral well as described herein. :

In some optional implementations, there is an in situ bitumen recovery startup process, comprising:

injecting a solvent-containing startup fluid into a multilateral infill well to form a solvent diluted zone, the multilateral infill well being positioned in a residual zone defined in between two flanking SAGD steam chambers, the multilateral infill well comprising:

a main well extending longitudinally along the residual zone; and

a plurality of branch side wells in fluid communication with the main well and each extending from the main well in a lateral direction in the residual zone toward and terminating in spaced relation with respect to one of the flanking SAGD steam chambers;

establishing fluid communication between at least one of the flanking SAGD steam chambers and the multilateral infill well; and

operating the multilateral infill well in production mode.

In some optional implementations, the branch side wells are only provided in a region of the residual zone that is colder and/or further away from the flanking SAGD steam chambers than other regions of the residual zone.

In some optional implementations, the branch side wells are only provided at a toe end of the main well.

In some optional implementations, the branch side wells are only provided below non-coalesced area of the flanking SAGD steam chambers.

In some optional implementations, the branch side wells are provided in greater number or greater length in a region of the residual zone that is colder and/or further away from the flanking SAGD steam chambers than other regions of the residual zone.

In some optional implementations, the branch side wells are provided in greater number or greater length at a toe end of the main well.

In some optional implementations, the branch side wells are provided in greater number or greater length in a region below non-coalesced area of the flanking SAGD steam chambers.

In some optional implementations, the injection of the solvent containing startup fluid is performed through the main well and the branch side wells simultaneously.

In some optional implementations, the injection of the solvent containing startup fluid comprises injecting into at least one isolated section of the multilateral infill well in order to form the solvent mobilized zone around the at least one isolated section.

In some optional implementations, the at least one isolated section comprises a plurality of isolated sections, and the injection of the solvent containing startup fluid comprises injecting

into the plurality of isolated sections of the multilateral infill well in order to form corresponding solvent mobilized zones around respective isolated sections.

In some optional implementations, the at least one isolated section of the multilateral infill well is selected in order to provide enhanced conformance of production along the infill well.

In some optional implementations, the at least one isolated section of the multilateral infill well is selected to inject the solvent-containing startup fluid into a surrounding first region that is colder and/or further away from the at least one adjacent SAGD steam chamber than other sections of the infill well.

In some optional implementations, the at least one isolated section of the multilateral infill well comprises one of the branch side well sections.

In some optional implementations, there is an in situ bitumen recovery startup process for an in situ system in a bitumen containing reservoir, the in situ system comprising a well pair comprising a horizontal injection well and a horizontal production well located below the horizontal injection well and separated by an interwell region, the process comprising:

injecting a solvent-containing startup fluid into the injection well below a fracturing pressure of the reservoir proximate the injection well;

providing a pressure sink in the production well to promote pressure drive of the solvent from the injection well toward the production well to mobilize bitumen in the interwell region; and

establishing fluid communication between the injection well and the production well.

In some optional implementations, the pressure sink is created by a pump associated with the production well for producing fluids therefrom.

In some optional implementations, the solvent-containing startup fluid contains a solvent selected from aromatic compounds and alkanes.

In some optional implementations, the solvent in the solvent-containing startup fluid comprises at least one of toluene, xylene, diesel, butane, pentane, hexane, heptane and naphtha.

In some optional implementations, the solvent in the solvent-containing startup fluid comprises naphtha.

In some optional implementations, the solvent in the solvent containing startup fluid consists of naphtha.

In some optional implementations, the solvent containing startup fluid further comprises water.

In some optional implementations, the process includes halting the injection and the production upon reaching an upper solvent concentration threshold in the produced fluid.

In some optional implementations, the produced fluid comprises between about 20% and about 50% volume of solvent based on the total volume of bitumen and solvent mixture.

In some optional implementations, the upper solvent concentration threshold is 50% volume based on the total volume of the bitumen and solvent mixture.

In some optional implementations, the solvent is selected to avoid asphaltene deposition.

In some optional implementations, the solvent containing startup fluid is formulated to avoid asphaltene deposition.

In some optional implementations, the solvent containing startup fluid is injected at a temperature between the initial reservoir temperature and about 150°C.

In some optional implementations, the solvent containing startup fluid is injected at a temperature above 100°C.

In some optional implementations, the solvent containing startup fluid is injected at a pressure between about initial reservoir pressure and about 100 kPa below the fracturing pressure of the reservoir proximate the injection well.

In some optional implementations, the interwell region is about 3 m to about 10m high. In some optional implementations, the interwell region is about 4 to 7 m high or about 5 m high.

In some optional implementations, the in situ system is a SAGD system.

In some optional implementations, the process includes:

(i) isolating a first horizontal startup interval of the well pair;

(ii) injecting the solvent containing startup fluid into the injection well at the first horizontal startup interval;

(iii) providing the pressure sink in the production well to promote downward pressure drive of the solvent from the injection well toward the production well at the first horizontal startup interval, to mobilize bitumen in a first portion of the interwell region;

(iv) establishing fluid communication between the injection well and the production well in the first portion of the interwell region;

(v) halting solvent injection and production in the first horizontal startup interval; and

(vi) isolating additional horizontal startup intervals one-by-one and repeating steps (ii) to (v) for each of the additional horizontal startup intervals.

In some optional implementations, the isolating is performed using packers, using at least one diverter, or using balls and/or sliding sleeves.

In some optional implementations, the injecting of the solvent-containing startup fluid is only done via the injection well.

In some optional implementations, the providing the pressure sink is done only in the production well.

In some optional implementations, the in situ system comprises a plurality of the well pairs arranged in parallel relationship to one another and the process comprises performing solvent assisted startup on the plurality of well pairs.

In some optional implementations, three is an in situ bitumen recovery startup process for an in situ system in a bitumen containing reservoir, the in situ system comprising a pair of wells, a horizontal injection well and a horizontal production well located above the horizontal injection well, the wells being separated by an interwell region, the process comprising:

injecting a solvent-containing startup fluid into one of the wells below a fracturing pressure of the reservoir;

providing a pressure sink in the other of the wells to promote pressure drive of the solvent from the one well toward the other well to mobilize bitumen in the interwell region; and

establishing fluid communication between the pair of wells.

In some optional implementations, the one well is the horizontal injection well and the other well is the horizontal production well.

In some optional implementations, the pressure sink is created by a pump associate with the production well for producing fluids therefrom.

In some optional implementations, the solvent containing startup fluid contains a solvent selected from aromatic compounds and alkanes.

In some optional implementations, the solvent in the solvent containing startup fluid comprises at least one of toluene, xylene, diesel, butane, pentane, hexane, heptane and naphtha.

In some optional implementations, the solvent in the solvent containing startup fluid comprises naphtha.

In some optional implementations, the solvent in the solvent containing startup fluid consists of naphtha.

In some optional implementations, the solvent containing startup fluid further comprises water.

In some optional implementations, the process includes halting the injection and the pressure sink upon reaching an upper solvent concentration threshold in the produced fluid.

In some optional implementations, the produced fluid comprises between about 20% and about 50% volume of solvent based on the total volume of bitumen and solvent mixture.

In some optional implementations, the upper solvent concentration threshold is 50% volume based on the total volume of the bitumen and solvent mixture.

In some optional implementations, the solvent is selected to avoid asphaltene deposition.

In some optional implementations, the solvent containing startup fluid is formulated to avoid asphaltene deposition.

In some optional implementations, the solvent containing startup fluid is injected at a temperature between the initial reservoir temperature 8 and about 150ºC.

In some optional implementations, the solvent containing startup fluid is injected at a temperature above 100ºC.

In some optional implementations, the solvent containing startup fluid is injected at a pressure between about initial reservoir pressure and about 100 kPa below the fracturing pressure of the reservoir proximate the injection well.

In some optional implementations, the interwell region is about 3 m to about 10m high.

In some optional implementations, the in situ system is a SAGD system.

In some optional implementations, the process includes:

(i) isolating a first horizontal startup interval of the well pair;

(ii) injecting the solvent containing startup fluid into the injection well at the first horizontal startup interval;

(iii) providing the pressure sink in the production well to promote downward pressure drive of the solvent from the injection well toward the production well at the first horizontal startup interval, to mobilize bitumen in a first portion of the interwell region;

(iv) establishing fluid communication between the injection well and the production well in the first portion of the interwell region;

(v) halting solvent injection and production in the first horizontal startup interval; and

(vi) isolating additional horizontal startup intervals one-by-one and repeating steps (ii) to (v) for each of the additional horizontal startup intervals.

In some optional implementations, the isolating is performed using packers, using at least one diverter, or using balls and / or sliding sleeves.

In some optional implementations, the injecting of the solvent containing startup fluid is only done via the one well.

In some optional implementations, the providing the pressure sink is done only in the other well.

In some optional implementations, the in situ system comprises a plurality of the well pairs arranged in parallel relationship to one another and the process comprises performing solvent assisted startup on the plurality of well pairs.

In some optional implementations, there is an in situ bitumen recovery startup process for an in situ system in a bitumen containing reservoir, the in situ system comprising a pair of wells, a horizontal injection well and a horizontal production well located above the horizontal injection well, the wells being separated by an interwell region, the process including:

(i) isolating a first horizontal startup interval of one of the wells;

(ii) injecting a solvent containing startup fluid into the first horizontal startup interval;

(iii) mobilizing bitumen of the interwell region proximate the first horizontal startup interval;

(iv) establishing fluid communication between the pair of wells in the first horizontal startup interval;

(v) halting solvent injection and production in the first horizontal startup interval; and

(vi) isolating additional horizontal startup intervals one-by-one and repeating steps (ii) to (v) for each of the additional horizontal startup intervals.

In some optional implementations, steps (ii) to (iv) include:

injecting the solvent containing startup fluid into the one of the wells below a fracturing pressure of the reservoir;

providing a pressure sink in the other of the wells to promote pressure drive of the solvent from the one well toward the other well to mobilize the bitumen in the interwell region in the first horizontal startup interval; and

establishing fluid communication between the pair of wells.

In some optional implementations, the one well is the horizontal injection well and the other well is the horizontal production well.

In some optional implementations, the isolating is performed by packers.

In some optional implementations, the isolating is performed by at least one diverter.

In some optional implementations, the isolating is performed using balls and/or sliding sleeves.

In some optional implementations, the horizontal startup intervals are sized to have lengths in accordance with well conformance.

In some optional implementations, the horizontal startup intervals are sized to have lengths of at most about 100 m.

In some optional implementations, the pressure sink is created by a pump associate with the production well for producing fluids therefrom.

In some optional implementations, the solvent containing startup fluid contains a solvent selected from aromatic compounds and alkanes.

In some optional implementations, the solvent in the solvent containing startup fluid comprises at least one of toluene, xylene, diesel, butane, pentane, hexane, heptane and naphtha.

In some optional implementations, the solvent in the solvent containing startup fluid comprises naphtha.

In some optional implementations, the solvent in the solvent containing startup fluid consists of naphtha.

In some optional implementations, the solvent containing startup fluid further comprises water.

In some optional implementations, the process includes halting the injection and the production upon reaching an upper solvent concentration threshold in the produced fluid.

In some optional implementations, the produced fluid comprises between about 20% and about 50% volume of solvent based on the total volume of bitumen and solvent mixture.

In some optional implementations, the upper solvent concentration threshold is 50% volume based on the total volume of the bitumen and solvent mixture.

In some optional implementations, the solvent is selected to avoid asphaltene deposition.

In some optional implementations, the solvent containing startup fluid is formulated to avoid asphaltene deposition.

In some optional implementations, the solvent containing startup fluid is injected at a temperature between the initial reservoir temperature 8 and about 150ºC.

In some optional implementations, the solvent containing startup fluid is injected at a temperature above 100ºC.

In some optional implementations, the solvent containing startup fluid is injected at a pressure between about initial reservoir pressure and about 100 kPa below the fracturing pressure of the reservoir proximate the injection well.

In some optional implementations, the interwell region is about 3 m to about 10m high.

In some optional implementations, the in situ system is a SAGD system.

In some optional implementations, the injecting of the solvent containing startup fluid is only done via the injection well.

In some optional implementations, the providing the pressure sink is done only in the production well.

In some optional implementations, the in situ system comprises a plurality of the well pairs arranged in parallel relationship to one another and the process comprises performing solvent assisted startup on the plurality of well pairs.

In some optional implementations, there is an in situ bitumen recovery startup process for a well that is an infill well or a step-out well, comprising:

(i) isolating a first horizontal startup interval of the well;

(ii) injecting a solvent containing startup fluid into the first horizontal startup interval;

(iii) mobilizing bitumen of a first region proximate the first horizontal startup interval;

(iv) halting solvent injection into the first horizontal startup interval; and

(v) establishing fluid communication between the well and at least one adjacent SAGD operation;

(vi) producing bitumen from the well.

In some optional implementations, there is provided an in situ bitumen recovery startup process, comprising:

injecting a startup fluid into a first horizontal well located in a bitumen-containing reservoir, where the fluid is injected below a fracturing pressure of the reservoir proximate the first horizontal well;

providing a pressure sink in a second horizontal well located adjacent to the first well to define an interwell region there-between, to promote pressure drive of the startup fluid from the first horizontal well toward the second horizontal well to mobilize bitumen in the interwell region; and

establishing fluid communication between the first horizontal well and the second horizontal well.

In some optional implementations, there is provided an in situ bitumen recovery startup process for a well in a bitumen containing reservoir, the well being approximately parallel to one or more adjacent SAGD steam chambers, the process comprising:

selecting a plurality of startup intervals along a length of the well;

for each of the plurality of startup intervals:

isolating the startup interval;

injecting a startup fluid into the startup interval; wherein the injected startup fluid penetrates the reservoir and mobilizes bitumen in a region proximate the interval;

ceasing startup fluid injection into the startup interval; and

establishing fluid communication with at least one adjacent SAGD chamber; and

producing bitumen from the well.

In some optional implementations, there is provided an in situ bitumen recovery startup process for a well selected from an infill well and a step-out well located adjacent to at least one SAGD steam chamber, the process comprising:

injection of a startup fluid into the well, wherein:

the injection is commenced when a surrounding region contiguous with the well is still substantially unheated by heat from the at least one SAGD steam chamber;

the injected startup fluid penetrates the surrounding region and mobilizes bitumen therein, thereby forming a mobilized zone in the surrounding region; and

the injection is performed to establish fluid communication between the at least one SAGD steam chamber and the mobilized zone; and

operating the well in production mode for bitumen recovery.

In some optional implementations, there is provided an in situ bitumen recovery startup process for an in situ system in a bitumen containing reservoir, the in situ system comprising a pair of wells comprising a horizontal injection well and a horizontal production well located below the horizontal injection well, the wells being separated by an interwell region, the process comprising:

(i) isolating a first horizontal startup interval of one of the wells;

(ii) injecting a solvent-containing startup fluid into the first horizontal startup interval;

(iii) mobilizing bitumen of the interwell region proximate the first horizontal startup interval;

(iv) establishing fluid communication between the pair of wells in the first horizontal startup interval;

(v) halting solvent injection and production in the first horizontal startup interval; and

(vi) isolating additional horizontal startup intervals one-by-one and repeating steps (ii) to (v) for each of the additional horizontal startup intervals.

In some optional implementations, there is provided an in situ bitumen recovery startup process for an in situ system in a bitumen containing reservoir, the in situ system comprising a pair of wells comprising a horizontal injection well and a horizontal production well located below the horizontal injection well, the wells being separated by an interwell region, the process comprising:

selecting a plurality of startup intervals along a length of the injection well;

for each of the plurality of startup intervals:

isolating the startup interval;

injecting a startup fluid into the startup interval; wherein the injected startup fluid penetrates the reservoir and mobilizes bitumen in a region proximate the interval;

ceasing startup fluid injection into the startup interval; and

establishing fluid communication between the pair of wells.

Also provided are systems for implementing any one or more of the processes described herein.

BRIEF DESCRIPTION OF THE DRAWINGS

Fig 1 is transverse cut view of first and second wells, e.g. a SAGD well pair.

Fig 2 is a side cross-sectional view of a SAGD operation showing one SADG well pair.

Fig 3 is a transverse cut view schematic of a SAGD operation with infill wells.

Fig 4 is a transverse cut view schematic of a SAGD operation with infill wells.

Fig 5 is a transverse cut view schematic of a SAGD operation with step-out wells.

Fig 6 is a transverse cut view of two well pairs with solvent halo areas.

Fig 7 is a graph of viscosity versus solvent concentration at different temperatures for bitumen-naphtha mixtures.

Fig 8 is a side cross-sectional view of an infill or step-out well.

Figs 9A to 9C are side cross-sectional view schematics of an infill or step-out well and part of a steam chamber.

Figs 10A to 10C are transverse cut view schematics of a SAGD operation with an infill well.

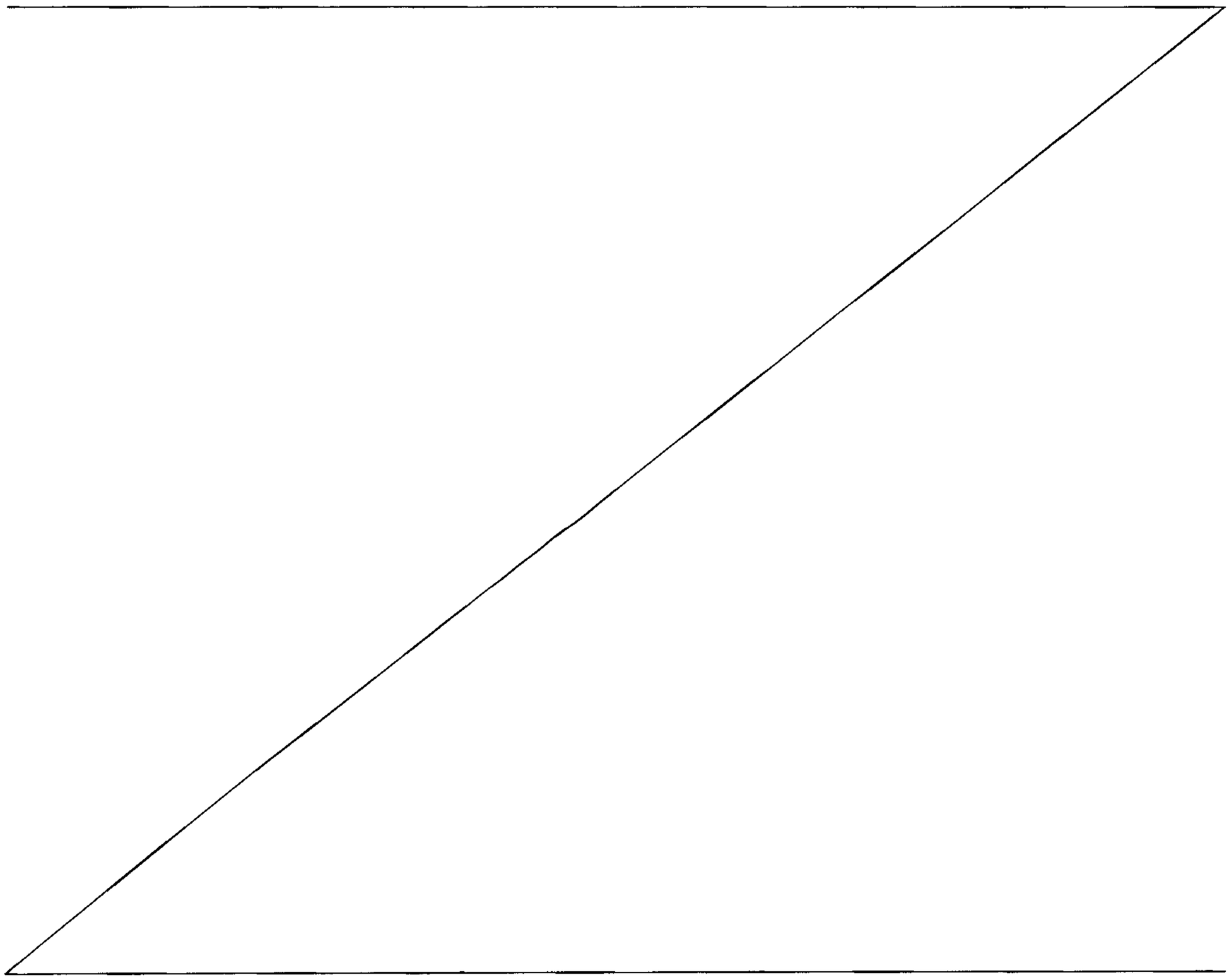
Figs 11A to 11C are top cross-sectional view schematics of a multilateral infill well and flanking SAGD steam chambers.

DETAILED DESCRIPTION

Solvent assisted startup techniques for in situ bitumen recovery are described below.

Solvent startup with well pairs and pressure sink

In some implementations, referring to Fig 1, an in situ recovery startup process may utilize a well pair, including a first well 10 and a second well 12 that are separated by an interwell



region 14. The process includes injecting a solvent containing startup fluid into one of the wells, for example into the first well 10, below a fracturing pressure of the reservoir proximate the first well 10; providing a pressure sink in the other well, for example the second well 12, to promote pressure drive of the solvent from the first well 10 toward the second well 12 to mobilize bitumen in the interwell region 14; and establishing fluid communication between the first well 10 and the second well 12.

In one optional scenario, the first well and second well may respectively be an injection well and a production well of a SAGD well pair, as illustrated in Fig 2.

In another optional scenario, the first well and second well may be at least a first infill well 16 and a second infill well 18, as illustrated in Figs 3 and 4. An infill well is a well that is positioned in a residual zone that is formed between two chambers, such as SAGD steam chambers, flanking either side of the residual zone. It should be noted that SAGD steam chambers may be created from steam injection in a SAGD operation and/or SAGD variant operations that may inject other fluids such as solvents, gases, and so on. The residual zone may have other boundaries such as over-burden and under-burden. The residual zone may be formed by flanking SAGD steam chamber areas as well as an overlying steam chamber area along at least a part of its length, in regions where the SAGD steam chambers have coalesced.

In another optional scenario, the first well 10 and second well may be a first infill well 20 and a second infill well 22, as illustrated in Fig 5.

It should be understood that other scenarios and configurations of first and second wells may be used.

In one implementation, as illustrated in Fig 2, the startup process is a SAGD startup process including the steps of providing an injection well 10 having a vertical portion 24 and a horizontal portion 26 extending from its vertical portion and a production well 12 having a vertical portion 28 and a horizontal portion 30 extending from its vertical portion. The horizontal portion 30 of the production well 12 is downwardly spaced away from the horizontal portion 26 of the injection well 10 defining the interwell region 14 in between.

The injection well 10, the production well 12 and the bitumen interval 32 are also shown in Fig 1.

The injection and production wells form a well pair 34 and there may be multiple well pairs arranged in parallel to one another in the reservoir. The well pairs 34 are connected to above ground equipment on a pad 36.

In one implementation, the solvent assisted SAGD startup process includes injecting a solvent containing startup fluid 38 into the injection well 10 and providing a pressure sink in the production well 12. The injection of solvent or a mixture of at least one solvent with water in the injection well may be performed below the fracturing pressure of the reservoir. The injection of the solvent containing startup fluid 38 may be performed at a pressure between about initial reservoir pressure, e.g. between 500 and 1000 kPa and about 100 kPa, for instance at a pressure at least 100 kPa below the fracturing pressure of the reservoir proximate the injection which will depend on the depth of the injection well. The initial reservoir pressure should be understood to be the pressure of the reservoir before injection of the startup fluid and prior to any substantial modification of the pressure that may be caused by injection, production or other operations. The solvent injection may begin at an initial pressure which may be increased until solvent-bitumen fluid flow occurs in the production well or up to at most the fracturing pressure of the reservoir. This solvent injection pressure constraint along with the pressure sink of the production well, promote downward pressure drive of the solvent from the injection well toward the production well, to mobilize the bitumen interval. The process also includes producing fluid from the production well using a pump or any other means to lower pressure in the producer.

In another optional implementation, the solvent assisted startup process is utilized with well pairs for which the interwell region has a lower amount of bitumen to improve sweeping of the solvent through the length or interval of the interwell region.

Referring to Fig 2, a subsurface pump 40 may be provided to provide the pressure sink in the production well 12. A drive 42, which may be surface or subsurface, may also be provided.

The process includes establishing fluid communication between the injection well and the production well.

Referring to Fig 2, the solvent containing startup fluid 38 may be provided via a solvent module 44 or a piping configuration for supplying solvent into the injection well 10. The

efficiency of the pre-soak process can be improved by creating a pressure sink in one of the wells driving the solvent from one well to the other. This process promotes confinement of the solvent to the volume between wells estimating that the decrease of the amount of solvent needed to approximately ¼ of the solvent needed in a pre-soak process.

In addition, the process may also include monitoring of the solvent/bitumen produced allowing real-time assessment of the efficiency, corrective actions if required and direct evidence of the bitumen free path developed between wells.

Fig 6 illustrates a comparison between solvent soaking into both injection and production wells versus solvent injection into one of the wells with a pressure sink in the other well. Fig 6 is also based on exemplary calculations and estimations as explained hereafter. For both cases, the injection and production wells were considered as spaced apart by d_i of 5 m. The assumed porosity of the interval between the wells was 33% and assumed So was 78%. The radius R_{cih} of the co-injection case halo was taken as 2.5 m and the lateral span S_{ps} of the pressure sink penetration region was taken as 2.5 m. The co-injection case halo area A_{cih} was $2\pi(2.5)^2 = 39m^2$ and the pressure sink case halo area A_{ps} was $\pi(2.5)(1.25) = 10m^2$.The minimum volumes needed for an 800m long well are as follows.

For solvent soak:

Bitumen volume = 8,000 m^3

20% naphtha content in the mobilized volume= 2,000 m^3

50 % naphtha content in the mobilized volume = 8,000 m^3

For solvent injection with pressure sink:

Bitumen volume = 2,000 m^3

20% naphtha content in the mobilized volume = 500 m^3

50 % naphtha content in the mobilized volume = 2,000 m^3

In addition, the following is for an extreme case accounting for unoptimized process and solvent loses.

For solvent soak:

90 % naphtha content in the mobilized volume = 72,000 m^3

For solvent injection with pressure sink:

90 % naphtha content in the mobilized volume = 18,000 m^3

Solvent assisted startup in SAGD well pair implementations leveraging a pressure sink may provide advantages such as efficient use of existing injection and production equipment for the respective injection and production wells, alignment of gravity with the pressure drive direction from the injection to production well, relatively small interwell region for SAGD well pairs, and so on.

In another implementation, as illustrated in Figs 3 and 4, the first and second wells may be at least two infill wells, which may be provided in between adjacent SAGD well pairs. Referring to Fig 3, a first infill well 16 and a second infill well 18 may be provided in adjacent relation to each other. Various configurations and relative positioning of the infill wells may be used. For example, two infill wells may be positioned beside one another to be at a generally similar depth and they may also be at a similar depth as the SAGD well pairs.

Referring to Fig 4, there may be more than two infill wells and the infill wells may be arranged in a certain configuration, for example where an upper infill well 46 is located above and in between two other lower infill wells 48, 50.

Referring back to Fig 3, one of the infill wells, for example infill well 16, may be used as an injection well to inject the solvent containing startup fluid into the surrounding region, while the other infill well 18 creates a pressure sink, in a similar manner to the SAGD well pair startup scenario described above. Either one of the two infill wells may be used as the injection well. It may be advantageous to select the injection well as the one located in a colder region of the reservoir compared to the pressure sink well.

Referring to Fig 4, one of the infill wells, for example infill well 46, may be used for injection of the solvent containing startup fluid, while one or more of the other wells 48, 50 are operated in pressure sink mode to promote pressure drive of the solvent from the injection infill well 46 toward the other infill wells to mobilize bitumen in the interwell region. Two of the infill wells may also be used as solvent injection wells while the other infill well is operated in pressure sink mode. It may be advantageous to only have one infill well equipped to inject solvent, to provide efficient use of injection equipment since all of the infill wells will likely be put on production mode at some point in time. When three of more wells

are used, the infill well that is in between the other two or has the shortest total distance to the other two wells may be used as the solvent injection well for efficient use of solvent. In the illustrated example, the upper infill well 46 may be the sole solvent injector well.

Referring to Figs 3 and 4, the adjacent SAGD well pairs 34a, 34b may have been operated to form steam chambers 52a, 52b extending upward into the reservoir. The infill wells may be started up at various stages of development of the adjacent steam chambers. For example, the steam chambers may be separate from each other, as illustrated, or may have coalesced prior to solvent assisted startup the infill wells. More regarding the steam chambers, temperature distribution in the infill region of the reservoir, and infill well startup strategies will be discussed further below.

In another implementation, as illustrated in Fig 5, the first and second wells may be at least two step-out wells 20, 22, one of which may be provided adjacent to a SAGD well pair 34. A step-out well is a well that is positioned in the reservoir in an adjacent zone to one SAGD steam chamber such that the adjacent zone is flanked by the SAGD steam chamber. A step-out well is distinguished from an infill well in that there is a SAGD steam chamber on only one side of the step-out well when the step-out well is installed and operated. At a later stage, once the SAGD steam chamber has developed over a first step-out well, another step-out well may be added adjacent to the first step-out well. In this sense, a step-out well does not have to be adjacent to a SAGD well pair, but only a steam chamber that is part of a gravity drainage operation.

A first step-out well 20 and a second step-out well 22 may be provided in adjacent relation to each other. Various configurations and relative positioning of the step-out wells may be used. For example, two step-out wells may be positioned beside one another to be at a generally similar depth and they may also be at a similar depth as the SAGD well pairs.

Referring still to Fig 5, one of the step-out wells, for example step-out well 22, may be used as an injection well to inject the solvent containing startup fluid into the surrounding region, while the other step-out well 20 creates a pressure sink, in a similar manner to the SAGD well pair or infill well startup scenarios described above. Either one of the two step-out wells may be used as the injection well. However, it may be advantageous to select the injection well as the step-out well located in a colder region of the reservoir compared to the pressure sink well and/or the step-out well located further away from the SAGD steam chamber 52.

For example, step-out well 20 may be put on production mode for creating the pressure sink and this well may also be more likely to produce mobilized bitumen due to its proximity to the steam chamber 52 and greater heat that may be available to reduce the viscosity of the bitumen proximate the closer step-out well 20. In addition, by injecting solvent through the further step-out well 22, where the surrounding region is colder, the solvent impact on viscosity reduction may be enhanced.

Solvent assisted startup in infill or step-out well implementations leveraging a pressure sink may provide advantages such as acceleration of startup and eventual bitumen recovery with efficient use of solvent.

Solvent assisted startup intervals

In some implementations, an in situ recovery startup process may include isolating intervals of a well and utilizing solvent injection into one or more of the isolated intervals one at a time. In one optional scenario, the well may be an injection well or a production well of a SAGD well pair. For example, the well may be a SAGD injection well as illustrated in Fig 2. In another optional scenario, the well may be an infill or step-out well 54, as illustrated in Fig 8.

In one implementation, as illustrated in Fig 2, the startup process is a SAGD startup process including isolating intervals of the injection well 10 and fluidly connecting these isolated intervals with the production well 12 one at a time using solvent injection. The injection well 10 may be divided into several isolated intervals illustrated as isolated startup intervals 56a, 56b, 56c, 56d and 56e. The solvent injection techniques described above may be performed at the isolated intervals one at a time. In this regard, it should be noted that the formation rock and bitumen in the interwell region is not homogeneous or constant along the length of the in situ well pair, which can have horizontal portions about 1000 m long. Certain intervals of the interwell region have higher permeability and other regions have higher bitumen content with lower effective permeability to start up fluid. The interval-based approach improves the solvent assisted startup performance.

An interval-based approach to the solvent assisted startup process may provide a number of advantages. First, the interval-based approach enables adjustability to adapt solvent assisted startup conditions and procedures to each interval along the well pair. This

adjustability may help adapt to geological and compositional variations of the interwell region, for example. Secondly, the interval-based approach helps to ensure solvent penetration and solvent assisted fluid communication along the length of the interwell region. Due to variations along the length of the interwell region running from the heel to the toe of the well pair, solvent injection along the entire length of the injection well may tend to have increased penetration at high permeability locations in the interwell region. Such high permeability locations may consist of low bitumen pockets or locations with naturally occurring higher permeability sand. If the solvent containing startup fluid is injected along the entire length of the injection well, it may quickly establish fluid communication between the injection and production well at a high permeability location, after which the injected solvent may tend to preferentially flow through the interwell region at this location, which can prematurely short-circuit the solvent assisted startup process. The interval-based solvent startup mitigates this problem by ensuring the solvent is injected into the interwell region at multiple intervals along the length of the well pair and thus reducing break through issues. Third, the interval-based approach enables reliability with progressive solvent injection along the entire length of the well pair.

It should be noted that the breakthrough issue of the solvent injection may also be addressed in a number of other ways optionally in combination with the interval-based approach. The solvent injection pressure and the production well pressure sink may be provided or modulated to promote uniform solvent penetration. Special injection or production well completions may be utilized to prevent solvent injection short-circuiting or to alleviate it in case break through is prematurely established such as by blocking off the portion of the injection well where the breakthrough has occurred and continuing the solvent injection in other portions of interwell region.

The isolating of the horizontal startup intervals may be done in a number of ways. For example, wellbore isolation methods used in hydraulic fracturing may be adapted for use in the present invention. One method uses frac-balls in combination with frac-ports and sliding sleeves, the frac-balls being delivered into the injection well to block or close off portions of the well. Each ball is smaller than the opening of all of the previous sleeves, but larger than the sleeve it is intended to open. Another method uses cup packers to isolate the horizontal startup intervals. A further method uses a diverter to block the flow through the annulus

between the formation and the exterior surface of the liner which can improve the efficiency of the process improving the containment in the selected startup intervals 56a, 56b, 56c, 56d and 56e. It should be noted that any other means may be used to create the horizontal startup intervals.

The horizontal startup intervals may be, for example, about 100 m long. The horizontal startup intervals may each have identical lengths or may have different lengths from each other is desired. Depending on the method used to create the isolated intervals, the order of solvent injection and interval activation may be from toe to heel, heel to toe, or another order. When a string of packers is used, the order may be from toe to heel of the injection well, that is the injection would start at the toe end interval 56e and work its way toward the heel end interval 56a of the injection well.

In another optional aspect, the isolation method may be performed in order that subsequent isolation intervals to be activated are as far away as possible from the previously activated interval. This kind of isolation method may be used in order to reduce the fluid communication channels established in one interval from prematurely joining with the solvent injection of an adjacent interval and thus further reduce short circuiting potential. In such a method, the intervals may be alternately activated at the heel and toe ends and work its way toward the middle of the well. The solvent injection, the isolation of intervals and establishing pressure sink conditions may be controlled to promote a full solvent sweep of each interval. In addition, when activating an isolated interval that is adjacent to a previously solvent swept interval, the process may be controlled to avoid or reduce premature channeling of the injected solvent to the previously swept adjacent mobilized zone. In another optional aspect, each of the horizontal startup intervals is operated to achieve solvent sweep and is halted either upon reaching an upper threshold of solvent concentration in the produced fluid or upon joining or coalescing its solvent sweep zone with an adjacent solvent sweep zone.

In another possible aspect, the horizontal startup intervals may be provided alternating on the upper and lower wells and the solvent injection and pressure sink may accordingly be provided to inject and produce from alternating wells. For instance, a first interval is isolated in the upper injection well and the pressure sink is provided in the lower production well to achieve fluid communication at the first interval. Next, after sufficient fluid flushing and the

like, the upper well is converted to production mode, the lower well is converted to injection mode and a second interval is isolated in the lower well. The solvent injection process is performed for the second interval until fluid communication is established in between the wells. Subsequent intervals may be provided in alternating wells which may be converted back and forth between injection and production modes. Appropriate pump configurations for the two wells would be provided and operated to manage this process.

The startup process may then use injection of a solvent containing fluid into one of the wells, preferably the injection well 10, below the fracturing pressure of the reservoir. The process then preferably includes producing fluid from the producer well 12 with a pump or any other means to lower pressure in the producer. After a given amount of solvent 27 has been injected, for example approximately 100 m^3 (for about a 100 m interval), and bitumen content is low in the production stream 58 as a result of the completion of the sweep process, injection and production may be halted. The next step of the process is to isolate another horizontal startup interval, which may have the same or different length as the first horizontal startup interval, and repeat the injection and production procedure until no bitumen is detected in the production stream. The other horizontal startup intervals are sequentially isolated and the solvent assisted process is repeated in each of the horizontal startup intervals until the full length of the well has been treated. While a length of about 100 m of the isolated horizontal startup intervals is preferred, they may be smaller or extended to more than 100 m if conformance is not impacted negatively. In one aspect, the startup interval isolation lengths are provided in accordance with conformance of the well pair and detected geological features.

Solvent assisted startup in SAGD well pair implementations with an interval based approach may provide advantages such as efficient use of existing injection and production equipment for the respective injection and production wells, alignment of gravity with the pressure drive direction from the injection to production well, relatively small interwell region for SAGD well pairs, and so on.

In another implementation, as illustrated in Fig 8, the startup process includes isolating intervals of an infill or step-out well 54 one at a time using solvent injection. The infill or step-out well 54 may be divided into several isolated intervals illustrated as isolated startup intervals 60a, 60b, 60c, 60d and 60e. Some of the solvent injection techniques described

herein may be performed at the isolated intervals one at a time. In this regard, it should be noted that the formation rock and bitumen in the surrounding region may not be homogeneous or constant along the length of the well 54, which can have horizontal portions about 1000 m long. Certain intervals of the surrounding region may have higher permeability and other regions have higher bitumen content with lower effective permeability to startup fluid. The interval-based approach improves the solvent assisted startup performance.

The interval-based startup strategy may also be implemented for the infill or step-out well 54 so as to startup one or more intervals at certain locations or having initial temperature characteristics.

For example, in the case of an infill well located in between two SAGD well pairs, the steam chambers of the SAGD well pairs may be at different stages of development along the length of the well pairs. It may be that near the heel end of the well pairs, the steam chambers have coalesced in an upper part of the reservoir, while at the toe end of the well pairs the steam chambers are spaced apart from each other. This uneven development of steam chambers may occur to varying degrees at different points along the well pairs, depending on various factors.

Figs 9A to 9C are side cross-sectional view schematics of an infill or step-out well 54 positioned in a reservoir. These Figures illustrate variations in the flanking steam chamber along the length of the well 54. In each case, part of a SAGD steam chamber 52 has developed sufficiently from one or more adjacent SAGD operations to be present overtop of the infill or step-out well. In the case of an infill well, two SAGD steam chambers may have coalesced overtop of the infill well 54 (e.g. as shown in Fig 10C) in at least one region along the length of the infill well 54. In other cases, an upper part of one steam chamber 52 may have simply developed overtop of an infill or step-out well 54 in at least one region along the length of the well.

Referring to Figs 9A to 9C, an infill well 54 may be located in a region of the reservoir such that there is a steam chamber 52 that has developed to be closer to certain locations along the length of the infill well 54.

Fig 9A illustrates a scenario where part of the steam chamber 52 has developed over top of the infill well at interval 56a, for example by coalescing with the adjacent steam chamber at that region. However, the toe end of the infill well includes an interval 56b toward which the steam chamber has not yet progressed. In such a situation, the solvent containing startup fluid may be injected into isolated interval 56b in order to form a solvent mobilized region surrounding interval 56b.

Fig 9B illustrates a scenario where two areas of the steam chamber 52 have developed over top of the infill well at intervals 56a and 56c, and the solvent containing startup fluid may be injected into isolated interval 56b in order to form a solvent mobilized region surrounding interval 56b.

Fig 9C illustrates a scenario where part of the steam chamber 52 has developed over top of the infill well at interval 56b, and the solvent containing startup fluid may be injected into isolated interval 56a and/or 56c in order to form a solvent mobilized region surrounding intervals 56a and/or 56c.

By favoring solvent injection into one or more intervals of the infill well that are colder and/or are further away from the steam chambers, the overall operation of the infill well once it is put on production mode can have improved conformance. Conformance, in this context, can be generally viewed as the degree of uniformity in space of the composition, fluid behaviour and thermal characteristics of a given recovery zone of the reservoir. Improved conformance along the length of an infill well, for example, can be viewed as having relatively consistent recovery characteristics along the length of the infill well and can be achieved by targeting intervals of the infill well that are colder and/or are further away from the steam chambers, as described for various implementations herein.

Thus, solvent assisted startup may be focused on target intervals of the infill well around which there is lower heat-enabled mobility, while other intervals of the infill well that are proximate to hotter regions of the reservoir require less or no solvent to facilitate startup. In addition, by injecting a greater amount of solvent into intervals of the infill well that are colder and/or further away from the steam chambers, the infill well can benefit from both the heat mobilizing effects of the steam chambers and the solvent mobilizing effects in the appropriate intervals, thereby enabling efficient use of solvent and heat.

For instance, in the case where the heel end of an infill well has substantial heat due to the adjacent SAGD steam chambers while the toe end does not, the solvent assisted startup may include injecting the solvent containing startup fluid into the toe end of the infill well prior to injecting the solvent containing startup fluid into the heel end of the infill well. Once the toe end has been pre-treated with solvent, the startup method may continue by injecting solvent or another fluid adjacent SAGD operation and the infill may be put on production mode. In this case, by favoring solvent injection into the toe end of the infill well, the overall infill well startup can be more consistent along the length of the infill well and the conformance may be improved for production along the length of the infill well.

Solvent assisted startup in infill or step-out well implementations with an interval based approach may provide advantages such as improved conformance and acceleration of startup and eventual bitumen recovery with efficient use of solvent

Solvent assisted startup for infill wells

One or more infill wells may be operated using solvent assisted startup to enhance the overall SAGD recovery of bitumen.

In some implementations, referring to Figs 10A to 10C, the infill well 54 is located in between two adjacent SAGD well pairs 34a, 34b having two corresponding steam chambers 52a, 52b. The solvent containing startup fluid is injected into the infill well 54 and forms a solvent diluted region 62 surrounding the infill well 54. As illustrated in Fig 10A, the solvent fluid may be injected prior to coalescence of the adjacent steam chambers 52a, 52b. The solvent diluted region 62 may mobilize the region surrounding the infill well 54 at a temperature around initial reservoir temperature, e.g. 10ºC. The initial reservoir temperature is the temperature of the reservoir prior to substantial heating of the reservoir, e.g. by steam injection or hot fluid circulation through wells, and is typically around 10ºC to 15ºC. The initial reservoir temperature should include where the reservoir may have been marginally heated by the drilling and completion operations or other operations that do not substantially heat the reservoir. As illustrated in Fig 10B, one or both of the steam chambers 52a, 52b may approach and eventually contact the solvent diluted region 62. As the steam chambers 52a, 52b approach the solvent diluted region 62, the steam chamber advancement may be accelerated due to the combined effect of heat and solvent dilution on viscosity reduction of the bitumen. The steam chambers 52a, 52b may therefore advance more rapidly toward

each other, eventually coalescing as shown in Fig 10C, and also advance rapidly toward the infill well 54. The infill well 54 may then be put on production mode.

In some situations, steam chambers of adjacent SAGD well pairs may have coalesced along some sections of the well length, but there may be remaining sections where no coalescence has occurred. In such cases, solvent assisted startup of an infill well may promote coalescence to occur in some or all of the remaining non-coalesced regions, thereby enabling greater conformance for the infill operations. The solvent assisted startup may use an interval-based approach by injecting solvent into intervals above which there is little or no coalescence or solvent may be injected into the entire infill well while ensuring that at least some solvent is injected below non-coalesced regions.

If the infill well is started up at a later stage when the steam chambers are relatively close or have fully developed and coalesced, the benefit of the solvent assisted startup may be reduced.

In some implementations, the infill well may be operated with solvent assisted startup such that the initial temperature around infill well is at initial reservoir temperature, e.g. 10°C.

Multilateral infill wells and step-out wells

Referring to Figs 11A to 11C, a multilateral infill well 64 may be positioned in between two flanking SAGD steam chambers and started up using one or more of the techniques described herein using solvent containing startup fluid. The multilateral infill well 64 includes a main well 66 that may extend longitudinally along the residual zone, at a length approximately the same as the adjacent SAGD well pairs 34a, 34b. The multilateral infill well 64 also includes at least one branch side well section 68. The branch side well sections 68 may be provided in certain locations to enhance the startup, conformance and/or performance of the multilateral infill well 64. For example, the branch side well sections 68 may be located and operated using solvent assisted startup sin accordance with the heat in the reservoir and the relative locations of the flanking or overlying steam chambers 52. The branch side well section 68 may be provided only in a region of the residual zone that is cooler and/or further away from the flanking steam chambers.

Fig 11A shows a multilateral infill well 64 with branch side well sections 68 provided in a wider region of the residual zone, in this case the region that is closer to the toe end of the SAGD operation.

Fig 11B shows a multilateral infill well 64 with branch side well sections 68 provided in wider region of the residual zone and also in a region above which no steam chamber coalescence has yet occurred.

Fig 11C shows a multilateral infill well 64 with branch side well sections 68 provided in two wider regions of the residual zone, one near the toe (branch well sections 68a) and the other near the heel (branch well sections 68b) of the SAGD operation.

The branch side well sections 68 may be provided in greater number and/or greater length in the wider and/or cooler regions of the residual zone. Solvent containing startup fluid may be injected into the entire multilateral infill well 64, including the branch side well sections 68. Solvent containing startup fluid may be injected into certain intervals or parts of the multilateral infill well 64, for example into certain branch side well sections that are located in wider and/or cooler regions of the residual zone.

Regarding step-out wells, it should be noted that a similar strategy may be adopted as is outlined for infill wells above and illustrated in Figs 11A to 11C, but with only one adjacent SAGD steam chamber.

Solvent injection regime

The injection regime may be controlled in a number of ways. In one optional implementation, the injection regime may be continuous such that the solvent containing startup fluid is continuously injected through the injection well. In some scenarios, continuous injection may be done until the produced fluid from the production well reaches a solvent fluid to bitumen ratio sufficiently high to halt injection and production.

In another optional implementation, the injection regime may be alternating such that a slug of the solvent containing startup fluid is injected followed by a slug of water. The solvent containing slug may have a volume depending on the given startup interval or based on calculations, estimates or field data from the reservoir or field, to provide an effective amount of solvent for achieving startup. The water slug may enable improved efficiency of solvent use, since the hydraulic pressure on the solvent slug injection is enabled by the

upstream water slug and thus solvent use is maximized for bitumen solubilization in the interwell region rather than merely providing sufficient hydraulics in the system. The alternating slug method may also be used by injecting a first pair of solvent and water slugs followed by subsequent pairs of solvent and water slugs, each subsequent pair of slugs decreasing in volume to continue the startup process while reducing the possibility of wasting solvent. In a further optional aspect, the solvent containing fluid and/or water slugs may be injected at a constant pressure or varying pressures. The solvent or slugs may be injected at progressively increasing or decreasing pressures depending on various factors such as the solvent content in the produced fluid. Pressure changes in the injection can alter and improve the solvent sweep efficiency, making it possible to sweep more bitumen from the interwell region.

In a further optional implementation, the injection and production well pressurization regime may be controlled to promote distribution of the solvent across the length of the horizontal startup interval or the injection well, as the case may be. More particularly, the solvent may be initially injected while the production well has no pressure sink, for a sufficient time to allow the solvent to begin penetrating generally across the entire length of the horizontal startup interval or the injection well. The production well is then activated to create the pressure sink to draw the solvent toward the production well and promote more uniform communication between the injection and production well over the length of the well pair.

Solvent containing startup fluid

The solvent containing startup fluid 38 may contain one or more of a number of solvents. Solvent may include aromatic compounds such as toluene or xylene or aromatic containing fluids such as diesel and the like. Solvent may include alkanes such as butane, pentane, hexane, heptane and the like or a combination of such alkanes. Solvent may be selected as an oil sands processing or by-product stream and in accordance with site availability and location. In one preferred aspect, solvent includes naphtha which may be available on site. Naphtha may be used as diluent in the produced bitumen containing stream and thus the naphtha addition may be seen as a diluent pre-treatment. In one optional aspect, the amount of naphtha diluent used in the startup process produces a market ready diluted bitumen stream, e.g. as “dilbit”, thus avoiding further treatment of the produced bitumen stream as would normally be required. The solvent containing fluid may contain for example

about 50% naphtha and about 50% water. The proportion of the solvent and water may be varied and optimized to achieve various results such as efficient solvent usage and depending on other operating conditions such as pressure and temperature. In another optional aspect, the process includes a step of performing a bitumen-solvent compatibility test for each batch of solvent to be used. The solvent is preferably selected to have no undesired interaction with bitumen in downhole conditions, such as asphaltene precipitation or deposition which could lead to fouling and various problems. The solvent may be provided in a concentration in the solvent containing startup fluid sufficent to minimize asphaltene deposition, such as a solvent concentration below the asphaltene precipitation threshold in the case of alkane solvents.

Based on bitumen and naphtha studies, the process preferably uses naphtha which does not show adverse interactions with bitumen and which with a content between 20% and 50% of naphtha in the final bitumen naphtha mixture, which lowers the cold bitumen viscosity to a point where it is mobile. Thus, a naphtha content above 20% allows fluid mobility. In one aspect, referring to Fig 2, the produced fluid 58 will have an initial concentration around 20% naphtha and this concentration will increase over time as the startup process continues to mobilize bitumen in the interwell region and establish fluid communication. When the produced fluid 58 reaches an upper threshold, such as 50% naphtha, production is halted. For instance, after a given amount of solvent has been injected and bitumen content is low in the produced fluid stream 58 as a result of completion of the sweep process, injection and production are halted.

Fig 7 shows viscosity versus solvent concentration at different temperatures for bitumen-naphtha mixtures. The naphtha allows a marked viscosity reduction of the bitumen.

Solvent assisted startup techniques described herein provide faster and more efficient solvent assisted startup of SAGD well pairs or infill or step-out wells from SAGD operations. Some of the techniques allow pressure differential to drive the solvent and minimize losses. Injecting solvent or a mixture of one or more solvents with water in the injection well and producing fluid from the production well with a pressure sink drives fluid from the injection well to the production well making the process fast and efficient with less solvent loses. Solvent lowers the bitumen viscosity while simultaneous injection/production keeps the solvent contained in the interwell region and drives solvent diluted bitumen to the production

well. Packers or diverter or any other means improves the conformance of the process along the horizontal intervals of the well. The elimination of the typical SAGD wells preheat lowers the steam to oil ratio (SOR) and allows earlier start-up with the associated financial benefit. The solvent assisted SADG startup process allows significant gas savings due to faster startup and reduced steam use.

In one example case, the injection well is given a completion including three down-hole pressure sensors with real-time surface reading, downhole temperature sensors with real-time surface reading, well head flow meter for water, well head flow meter for bitumen-naphtha mixture and a spinner log for horizontal wells. The production well is given a completion including PCP pump landed as close as possible to the reservoir, three down-hole pressure sensors with real-time surface reading, downhole temperature sensors with real-time surface reading.

Optional detection steps

In an optional implementation, the startup process includes a preliminary detection stage for assessing various features of the reservoir and wells such as cold water mobility and cold solvent mobility.

The cold water mobility test may include:

- Starting the producer PCP while keeping constant downhole pressure; registering pressure in the injection well and adjacent well pairs; when a pressure drop is detected at an adjacent well pair or after a given time interval, e.g. 48 hrs, pumping; and stopping production and wait for pressure recovery.
- Starting the producer PCP while keeping substantially constant downhole pressure, injecting cold water in the injector at about 50% of the maximum allowed injection pressure; waiting for pressure and flow stabilization; and running spinner log in injection well.

The cold solvent mobility test may include:

- Keeping an injection/production ratio below about 0.7; adding solvent to the injection stream until 50 % v/vi is reached; waiting for pressure and flow stabilization; running spinner log in injection well; taking samples of produced

bitumen, for instance to determine viscosity and naphtha content; measuring water cut; when production is stable (water cut), increasing the solvent content until 100 % solvent is injected; waiting for pressure and flow stabilization; and running spinner log in injection well.

The following is an example procedural overview for implementation of some scenarios described herein:

- Conformance control:
    - When production is stable (water cut and naphtha content of the bitumen produced as determined by density measurement in the field) inject a slug of diverter to control the conformance of the process.
    - Repeat the cold solvent mobility step alternating with diverter slugs several times, e.g. at least four times.
- Warm water mobility:
    - Increase the bottom-hole temperature of the injected water to about 50°C, which will require steam at the well head. Repeat steps with solvent and diverter.
    - Increase the bottom-hole temperature to 100°C. Repeat steps with solvent and diverter.
- Circulate steam in the injector and the producer with slight pressure changes to evaluate communication between wells and start them up in SAGD mode.

In other implementations, the startup process may include a monitoring step for assessing the status of the startup process. For example, for first and second wells, such as a SAGD well pair, the solvent assisted fluid communication between the wells may be monitored by circulating another fluid, such as steam, into the both wells and monitoring whether the steam pressure equalize, thereby indicating a fluid connection. In addition, after one or more solvent injection cycles, the interwell region may be heated and then cooled and the temperature reduction along the interwell region may be monitored to detect one or more locations where the solvent was able to significantly penetrate the formation.

Various optional aspects of the present invention may help to mitigate technical challenges of the SAGD startup process. For instance, the cold water infectivity tests prior to performing the process allows adjustments for low injectivity. Driving solvent from one well to the other by creating a pressure sink in the producer and actually producing fluids as well as maintaining injection/production ratio below 0.7 helps to minimize solvent loss. Using diverter or the like to improve conformance along the well can make a particularly significant difference especially in early behavior of the wells. Furthermore, performing and analyzing compatibility samples and testing to asphaltene deposition can help quickly evaluate this potential challenge and solvent selection can be modified, e.g. from an alkane based solvent to a naphtha-based solvent.

Referring to Fig 2, the surface equipment provided to inject the solvent may include pumps and holding tanks along with monitoring equipment to monitor pressure, flow of solvent, slug volumes, and the like as the case may be. The surface equipment may include mixing means (not illustrated) to mix pure solvent with water to create the solvent containing startup fluid 27. The mixing equipment may include static mixers, tee pipe junctions, to generally provide sufficient mixing energy to blend the solvent and water. The surface equipment may also include tanks 36 for the produced fluid 34 and pumps 38 for supplying the produced fluid to desired locations, recycling, solvent removal or downstream processing as the case may be. There may be multiple tanks for holding the production fluid 34 produced at different periods of the startup process, e.g. a holding tank for receiving bitumen-rich produced fluid, a holding tank for receiving solvent-rich produced fluid and a holding tank for receiving produced fluid with a composition suitable to be considered “dilbit”.

In one example, a SAGD well pair was started up with solvent injection. A naphtha based solvent was injected through an injection well while the underlying production well created a pressure sink. The solvent was injected through two different intervals that were not adjacent to each other. Solvent was first injected through a 100 m interval at the toe end of the injection well. Solvent was then injected though a 100 m interval spaced 250 m away from the first toe end interval. Evidence of fluid communication was observed. When steam was circulated through the wells, pressure equalization was observed, indicating that the steam was fluidly communication between the injection and production wells. Secondly, in the intervals where solvent injection was performed, longer cooling times were observed in

response to reducing the heat injection, indicating that the heat penetration in these regions was greater due to solvent assisted mobilization.

In addition, two solvent injection amounts were tested. For one tested interval, the amount of solvent injected was at a 1:1 ratio with respect to the estimated bitumen in the interwell region for that interval. For another tested interval, the amount of solvent injected was at a 1:2 ratio with respect to the estimated bitumen in the interwell region for that interval. This indicates that lower solvent injection quantities are possible to achieve similar startup effects.

In some implementations, the solvent containing startup fluid may be provided upon injection at a temperature between the initial reservoir temperature and about 150ºC. The solvent containing startup fluid may be injected at a temperature above 100ºC. The solvent containing startup fluid may be injected at a temperature around ambient temperatures, which may depend on the season, e.g. between 15ºC and 25ºC.

In some implementations, various techniques described herein may be combined with other techniques described herein. For example, multilateral wells may be used with the interval approach (by providing isolated intervals in the multilateral well, e.g. such intervals may be the whole or part of one or more branch side well sections) and/or the pressure sink approach (by providing another well for injection or providing pressure sink relative to the multilateral infill well). Another example is that the multilateral well may be a step-out well with only one adjacent SAGD steam chamber. Many other examples of inter-combining one or more techniques described herein are also possible as should be apparent from the present description.

In some other implementations, various solvent assisted startup techniques as described may be used with other configurations such as vertical or slanted infill or step-out wells, SAGD variants such as solvent-SAGD operations, and/or infill or step-out wells that are provided in between or adjacent to steam chambers or mobilized zones other than SAGD steam chambers.

Indeed, various other variants, embodiment and aspects may also be used under the present invention.

CLAIMS

1. An in situ bitumen recovery startup process for a well in a bitumen containing reservoir, the well being approximately parallel to one or more adjacent SAGD steam chambers, the process comprising:

selecting a plurality of startup intervals along a length of the well;

for each of the plurality of startup intervals:

isolating the startup interval;

injecting a solvent-containing startup fluid into the startup interval; wherein the injected startup fluid penetrates the reservoir and mobilizes bitumen in a region proximate the interval;

ceasing solvent injection into the startup interval; and

establishing fluid communication with at least one adjacent SAGD chamber; and

producing bitumen from the well.

2. The process of claim 1, further comprising selecting one or more of the startup intervals based on a distance from the well within the selected startup interval to the one or more adjacent SAGD steam chambers.

3. The process of claim 1, further comprising selecting one or more of the startup intervals based on a distance based on a temperature of the reservoir around the selected startup interval.

4. The process of any one of claims 1 to 3, wherein the well is a step-out well provided in a recovery zone of the reservoir in spaced relation with respect to one adjacent SAGD steam chamber.

5. The process of 4, wherein at least one of the startup intervals is selected to inject the solvent-containing startup fluid into a surrounding region that is at initial reservoir temperature.

6. The process of 4 or 5, wherein at least one of the startup intervals is selected to inject the solvent-containing startup fluid into a surrounding region that is colder than other intervals of the step-out well.

7. The process of any one of claims 4 to 6, wherein at least one of the startup intervals is selected to inject the solvent-containing startup fluid into a surrounding region that is further away from the adjacent SAGD steam chamber than other intervals of the step-out well.

8. The process of any one of claims 4 to 7, comprising injecting the solvent-containing startup fluid through a selected startup interval into a surrounding region of the reservoir in a greater amount, for a greater duration and/or at an earlier injection time, based on the temperature of the surrounding region and/or a distance from the well within the selected startup interval to the adjacent SAGD steam chamber.

9. The process of claim 8, wherein the injecting of the greater amount, for the greater duration and/or at the earlier injection time is performed where the surrounding region of the selected startup interval is at initial reservoir temperature and/or is colder than other intervals of the well.

10. The process of claim 8, wherein the injecting of the greater amount, for the greater duration and/or at the earlier injection time is performed where the distance from the well within the selected startup interval to the adjacent SAGD steam chamber is greater than other intervals of the well.

11. The process of any one of claims 1 to 3 wherein the well is an infill well provided in a residual zone, the residual zone being defined in between two flanking SAGD steam chambers.

12. The process of claim 11, wherein at least one of the startup intervals is selected to inject the solvent-containing startup fluid into a surrounding region that is at initial reservoir temperature.

13. The process of claim 11 or 12, wherein at least one of the startup intervals is selected to inject the solvent-containing startup fluid into a surrounding region that is colder than other intervals of the infill well.

14. The process of any one of claims 11 to 13, wherein at least one of the startup intervals is selected to inject the solvent-containing startup fluid into a surrounding region that is further away from the flanking SAGD steam chambers than other intervals of the infill well.

15. The process of any one of claims 11 to 14, comprising injecting the solvent-containing startup fluid through a selected startup interval into a surrounding region of the reservoir in a greater amount, for a greater duration and/or at an earlier injection time, based on the temperature of the surrounding region, a distance from the well within the selected startup interval to the flanking SAGD steam chambers, and/or whether the flanking SAGD steam chambers have coalesced above the selected startup interval.

16. The process of claim 15, wherein the injecting of the greater amount, for the greater duration and/or at the earlier injection time is performed where the surrounding region of the selected startup interval is at initial reservoir temperature and/or is colder than other intervals of the well.

17. The process of claim 15, wherein the injecting of the greater amount, for the greater duration and/or at the earlier injection time is performed where the distance from the well within the selected startup interval to the adjacent SAGD steam chamber is greater than other intervals of the well.

18. The process of claim 15, wherein the injecting of the greater amount, for the greater duration and/or at the earlier injection time is performed wherein where the flanking SAGD steam chambers have not yet coalesced above the selected startup interval.

19. The process of any one of claims 1 to 18, wherein the isolating is performed by packers.

20. The process of any one of claims 1 to 18, wherein the isolating is performed by at least one diverter.

21. The process of any one of claims 1 to 18, wherein the isolating is performed using balls and/or sliding sleeves.

22. The process of any one of claims 1 to 21, wherein the startup intervals are sized to have lengths in accordance with well conformance.

23. The process of any one of claims 1 to 22, wherein the startup intervals are sized to have lengths of at most about 100 m.

24. The process of any one of claims 1 to 23, wherein the solvent-containing startup fluid contains a solvent selected from aromatic compounds and alkanes.

25. The process of claim 24, wherein the solvent in the solvent-containing startup fluid comprises at least one of toluene, xylene, diesel, butane, pentane, hexane, heptane and naphtha.

26. The process of claim 24, wherein the solvent in the solvent-containing startup fluid comprises naphtha.

27. The process of claim 26, wherein the solvent in the solvent-containing startup fluid consists of naphtha.

28. The process of any one of claims 1 to 27, wherein the solvent-containing startup fluid further comprises water.

29. The process of any one of claims 1 to 28, wherein the solvent-containing startup fluid is formulated to avoid asphaltene deposition.

30. The process of any one of claims 1 to 29, wherein the solvent-containing startup fluid is injected at a temperature between the initial reservoir temperature 8 and about 150°C.

31. The process of any one of claims 1 to 30, wherein the solvent-containing startup fluid is injected at a temperature above 100°C.

32. The process of any one of claims 1 to 31, wherein the solvent-containing startup fluid is injected at a pressure between about initial reservoir pressure and about 100 kPa below the fracturing pressure of the reservoir proximate the well.

33. The process of any one of claims 1 to 32, wherein the well is a multilateral well comprising:

a main well extending longitudinally in spaced relation with respect to the at least one adjacent SAGD steam chamber; and

a plurality of branch side wells in fluid communication with the main well and extending from the main well in a lateral direction.

34. An in situ bitumen recovery startup process for a well selected from an infill well and a step-out well located adjacent to at least one SAGD steam chamber, the process comprising:

injection of a solvent-containing startup fluid into the well, wherein:

the injection is commenced when a surrounding region contiguous with the well is still substantially unheated by heat from the at least one SAGD steam chamber;

the injected solvent-containing startup fluid penetrates the surrounding region and mobilizes bitumen therein, thereby forming a solvent mobilized zone in the surrounding region; and

the injection is performed to establish fluid communication between the at least one SAGD steam chamber and the solvent mobilized zone; and

operating the well in production mode for bitumen recovery.

35. The process of claim 34, wherein the injection of the solvent-containing startup fluid is performed along the entire length of the well.

36. The process of claim 34, wherein the injection of the solvent-containing startup fluid comprises injecting into at least one isolated section of the well in order to form the solvent mobilized zone around the at least one isolated section.

37. The process of claim 36, wherein the at least one isolated section comprises a plurality of isolated sections, and the injection of the solvent-containing startup fluid comprises injecting into the plurality of isolated sections of the well in order to form corresponding solvent mobilized zones around respective isolated sections.

38. The process of claim 36 or 37, wherein the at least one isolated section of the well is selected in order to provide enhanced conformance of production along the well.

39. The process of any one of claims 36 to 38, wherein the at least one isolated section of the well is selected to inject the solvent-containing startup fluid into a surrounding first region that is colder and/or further away from the at least one adjacent SAGD steam chamber than other sections of the well.

40. The process of any one of claims 36 to 39, wherein the well is a multilateral well comprising:

a main well extending longitudinally in spaced relation with respect to the at least one adjacent SAGD steam chamber; and

a plurality of branch side wells in fluid communication with the main well and extending from the main well in a lateral direction.

41. An in situ bitumen recovery startup process for an infill well located in a residual zone defined between two flanking SAGD steam chambers, the process comprising:

injection of a solvent-containing startup fluid into the well, wherein:

the injection is commenced prior to coalescence of the two flanking SAGD steam chambers along the length of the infill well;

the injected solvent-containing startup fluid penetrates the reservoir and mobilizes bitumen therein, thereby forming a solvent mobilized zone; and

the injection is performed to accelerate advancement of the at least one flanking SAGD steam chamber toward the infill well through the solvent diluted zone and establish fluid communication between the at least one SAGD steam chamber and the solvent mobilized zone; and

operating the infill well in production mode for bitumen recovery from the residual zone.

42. The process of claim 41, wherein the injection of the solvent-containing startup fluid is performed along the entire length of the infill well.

43. The process of claim 41, wherein the injection of the solvent-containing startup fluid comprises injecting into at least one isolated section of the infill well in order to form the solvent mobilized zone around the at least one isolated section, wherein the injection into the at least one isolated section is commenced prior to coalescence of the two flanking SAGD steam chambers along a length corresponding to the at least one isolated section.

44. The process of claim 43, wherein the at least one isolated section comprises a plurality of isolated sections, and the injection of the solvent-containing startup fluid comprises injecting into the plurality of isolated sections of the infill well in order to form corresponding solvent mobilized zones around respective isolated sections, wherein the injection into each of the isolated sections is commenced prior to coalescence of the two flanking SAGD steam chambers along respective lengths corresponding to the isolated sections.

45. The process of claim 43 or 44, wherein the at least one isolated section of the infill well is selected in order to provide enhanced conformance of production along the infill well.

46. The process of any one of claims 43 to 45, wherein the at least one isolated section of the infill well is further selected to inject the solvent-containing startup fluid into a surrounding first region that is colder and/or further away from the at least one adjacent SAGD steam chamber than other sections of the infill well.

47. The process of any one of claims 41 to 46, wherein the infill well is a multilateral well comprising:

a main well extending longitudinally in spaced relation with respect to the at least one adjacent SAGD steam chamber; and

a plurality of branch side wells in fluid communication with the main well and extending from the main well in a lateral direction.

48. An in situ bitumen recovery startup process, comprising:

injecting a solvent-containing startup fluid into a multilateral infill well to form a solvent diluted zone, the multilateral infill well being positioned in a residual zone defined in between two flanking SAGD steam chambers, the multilateral infill well comprising:

a main well extending longitudinally along the residual zone; and

a plurality of branch side wells in fluid communication with the main well and each extending from the main well in a lateral direction in the residual zone toward and terminating in spaced relation with respect to one of the flanking SAGD steam chambers;

establishing fluid communication between at least one of the flanking SAGD steam chambers and the multilateral infill well; and

operating the multilateral infill well in production mode.

49. The process of claim 48, wherein the branch side wells are only provided in a region of the residual zone that is colder and/or further away from the flanking SAGD steam chambers than other regions of the residual zone.

50. The process of claim 48 or 49, wherein the branch side wells are only provided at a toe end of the main well.

51. The process of any one of claims 48 to 50, wherein the branch side wells are only provided below non-coalesced area of the flanking SAGD steam chambers.

52. The process of claim 48, wherein the branch side wells are provided in greater number or greater length in a region of the residual zone that is colder and/or further away from the flanking SAGD steam chambers than other regions of the residual zone.

53. The process of claim 52, wherein the branch side wells are provided in greater number or greater length at a toe end of the main well.

54. The process of claim 52 or 53, wherein the branch side wells are provided in greater number or greater length in a region below non-coalesced area of the flanking SAGD steam chambers.

55. The process of any one of claims 48 to 54, wherein the injection of the solvent-containing startup fluid is performed through the main well and the branch side wells simultaneously.

56. The process of any one of claims 48 to 55, wherein the injection of the solvent-containing startup fluid comprises injecting into at least one isolated section of the multilateral infill well in order to form the solvent mobilized zone around the at least one isolated section.

57. The process of claim 56, wherein the at least one isolated section comprises a plurality of isolated sections, and the injection of the solvent-containing startup fluid comprises injecting into the plurality of isolated sections of the multilateral infill well in order to form corresponding solvent mobilized zones around respective isolated sections.

58. The process of claim 56 or 57, wherein the at least one isolated section of the multilateral infill well is selected in order to provide enhanced conformance of production along the infill well.

59. The process of any one of claims 56 to 58, wherein the at least one isolated section of the multilateral infill well is selected to inject the solvent-containing startup fluid into a surrounding first region that is colder and/or further away from the at least one adjacent SAGD steam chamber than other sections of the infill well.

60. The process of any one of claims 56 to 59, wherein the at least one isolated section of the multilateral infill well comprises one of the branch side well sections.

61. An in situ bitumen recovery startup process for a well in a bitumen containing reservoir, the well being approximately parallel to one or more adjacent SAGD steam chambers, the process comprising:

selecting a plurality of startup intervals along a length of the well;

for each of the plurality of startup intervals:

isolating the startup interval;

injecting a startup fluid into the startup interval; wherein the injected startup fluid penetrates the reservoir and mobilizes bitumen in a region proximate the interval;

ceasing startup fluid injection into the startup interval; and

establishing fluid communication with at least one adjacent SAGD chamber; and

producing bitumen from the well.

62. An in situ bitumen recovery startup process for a well selected from an infill well and a step-out well located adjacent to at least one SAGD steam chamber, the process comprising:

injection of a startup fluid into the well, wherein:

the injection is commenced when a surrounding region contiguous with the well is still substantially unheated by heat from the at least one SAGD steam chamber;

the injected startup fluid penetrates the surrounding region and mobilizes bitumen therein, thereby forming a mobilized zone in the surrounding region; and

the injection is performed to establish fluid communication between the at least one SAGD steam chamber and the mobilized zone; and

operating the well in production mode for bitumen recovery.

63. An in situ bitumen recovery startup process for an in situ system in a bitumen containing reservoir, the in situ system comprising a pair of wells comprising a horizontal injection well and a horizontal production well located below the horizontal injection well, the wells being separated by an interwell region, the process comprising:

(i) isolating a first horizontal startup interval of one of the wells;

(ii) injecting a solvent-containing startup fluid into the first horizontal startup interval;

(iii) mobilizing bitumen of the interwell region proximate the first horizontal startup interval;

(iv) establishing fluid communication between the pair of wells in the first horizontal startup interval;

(v) halting solvent injection and production in the first horizontal startup interval; and

(vi) isolating additional horizontal startup intervals one-by-one and repeating steps (ii) to (v) for each of the additional horizontal startup intervals.

64. The process of claim 63, wherein the one well is the horizontal injection well and the other well is the horizontal production well.

65. The process of claim 63 or 64, wherein the isolating is performed by packers.

66. The process of any one of claims 63 to 65, wherein the isolating is performed by at least one diverter.

67. The process of any one of claims 63 to 65, wherein the isolating is performed using balls and/or sliding sleeves.

68. The process of any one of claims 63 to 67, wherein the horizontal startup intervals are sized to have lengths in accordance with well conformance.

69. The process of any one of claims 63 to 68, wherein the horizontal startup intervals are sized to have lengths of at most about 100 m.

70. The process of any one of claims 63 to 69, wherein the solvent-containing startup fluid contains a solvent selected from aromatic compounds and alkanes.

71. The process of claim 70, wherein the solvent in the solvent-containing startup fluid comprises at least one of toluene, xylene, diesel, butane, pentane, hexane, heptane and naphtha.

72. The process of claim 71, wherein the solvent in the solvent-containing startup fluid comprises naphtha.

73. The process of claim 72, wherein the solvent in the solvent-containing startup fluid consists of naphtha.

74. The process of any one of claims 63 to 73, wherein the solvent-containing startup fluid further comprises water.

75. The process of any one of claims 63 to 74, comprising halting the injection and the production upon reaching an upper solvent concentration threshold in the produced fluid.

76. The process of claim 75, wherein the produced fluid comprises between about 20% and about 50% volume of solvent based on the total volume of bitumen and solvent mixture.

77. The process of claim 75, wherein the upper solvent concentration threshold is 50% volume based on the total volume of the bitumen and solvent mixture.

78. The process of any one of claims 63 to 77, wherein the solvent is selected to avoid asphaltene deposition.

79. The process of any one of claims 63 to 78, wherein the solvent-containing startup fluid is formulated to avoid asphaltene deposition.

80. The process of any one of claims 63 to 79, wherein the solvent-containing startup fluid is injected at a temperature between the initial reservoir temperature 8 and about 150°C.

81. The process of any one of claims 63 to 80, wherein the solvent-containing startup fluid is injected at a temperature above 100°C.

82. The process of any one of claims 63 to 81, wherein the solvent-containing startup fluid is injected at a pressure between about initial reservoir pressure and about 100 kPa below the fracturing pressure of the reservoir proximate the injection well.

83. The process of any one of claims 63 to 82, wherein the interwell region is about 3 m to about 10m.

84. The process of any one of claims 63 to 83, wherein the in situ system is a SAGD system.

85. The process of any one of claims 63 to 84, wherein the injecting of the solvent-containing startup fluid is only done via the injection well.

86. The process of any one of claims 63 to 85, wherein the in situ system comprises a plurality of the well pairs arranged in parallel relationship to one another and the process comprises performing solvent-assisted startup on the plurality of well pairs.

87. An in situ bitumen recovery startup process for an in situ system in a bitumen containing reservoir, the in situ system comprising a pair of wells comprising a horizontal injection well and a horizontal production well located below the horizontal injection well, the wells being separated by an interwell region, the process comprising:

selecting a plurality of startup intervals along a length of the injection well;

for each of the plurality of startup intervals:

isolating the startup interval;

injecting a startup fluid into the startup interval; wherein the injected startup fluid penetrates the reservoir and mobilizes bitumen in a region proximate the interval;

ceasing startup fluid injection into the startup interval; and

establishing fluid communication between the pair of wells.

88. The process of claim 87, wherein the isolating is performed by packers.

89. The process of claim 87, wherein the isolating is performed by at least one diverter.

90. The process of claim 87, wherein the isolating is performed using balls and/or sliding sleeves.

91. The process of any one of claims 87 to 90, wherein the startup intervals are sized to have lengths in accordance with well conformance.

92. The process of any one of claims 87 to 91, wherein the startup intervals are sized to have lengths of at most about 100 m.

93. The process of any one of claims 87 to 92, wherein the startup fluid is a solvent-containing startup fluid containing a solvent selected from aromatic compounds and alkanes.

94. The process of claim 93, wherein the solvent in the solvent-containing startup fluid comprises at least one of toluene, xylene, diesel, butane, pentane, hexane, heptane and naphtha.

95. The process of claim 94, wherein the solvent in the solvent-containing startup fluid comprises naphtha.

96. The process of claim 95, wherein the solvent in the solvent-containing startup fluid consists of naphtha.

97. The process of any one of claims 87 to 96, wherein the startup fluid comprises water.

98. The process of any one of claims 87 to 97, comprising halting the injection and the production upon reaching an upper concentration threshold in the produced fluid.

99. The process of any one of claims 87 to 98, wherein the startup fluid is formulated to avoid asphaltene deposition.

100. The process of any one of claims 87 to 99, wherein the startup fluid is injected at a temperature between the initial reservoir temperature and about 150°C.

101. The process of any one of claims 87 to 100, wherein the startup fluid is injected at a temperature above 100°C.

102. The process of any one of claims 87 to 101, wherein the startup fluid is injected at a pressure between about initial reservoir pressure and about 100 kPa below the fracturing pressure of the reservoir proximate the injection well.

103. The process of any one of claims 87 to 102, wherein the interwell region is about 3 m to about 10m.

104. The process of any one of claims 87 to 103, wherein the in situ system is a SAGD system.

105. The process of any one of claims 87 to 104, wherein the in situ system comprises a plurality of the well pairs arranged in parallel relationship to one another.

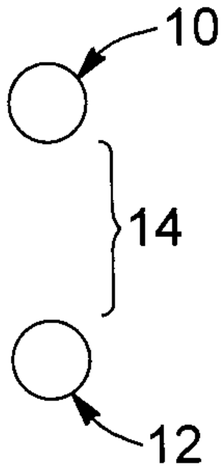

10
14
12

FIG. 1

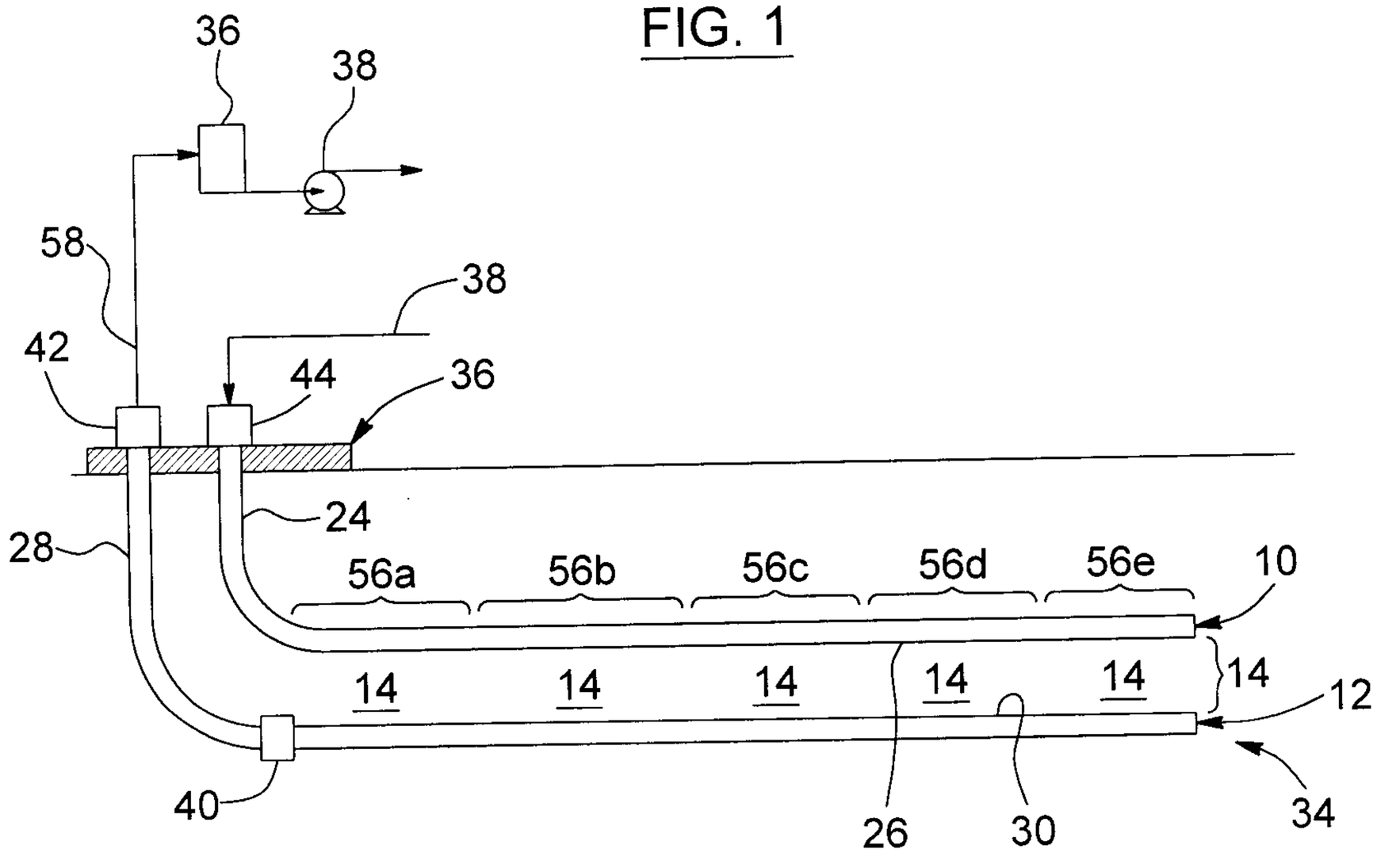

36
38
58
38
42
44
36
24
28
56a
56b
56c
56d
56e
10
14
14
14
14
14
14
12
40
26
30
34

FIG. 2

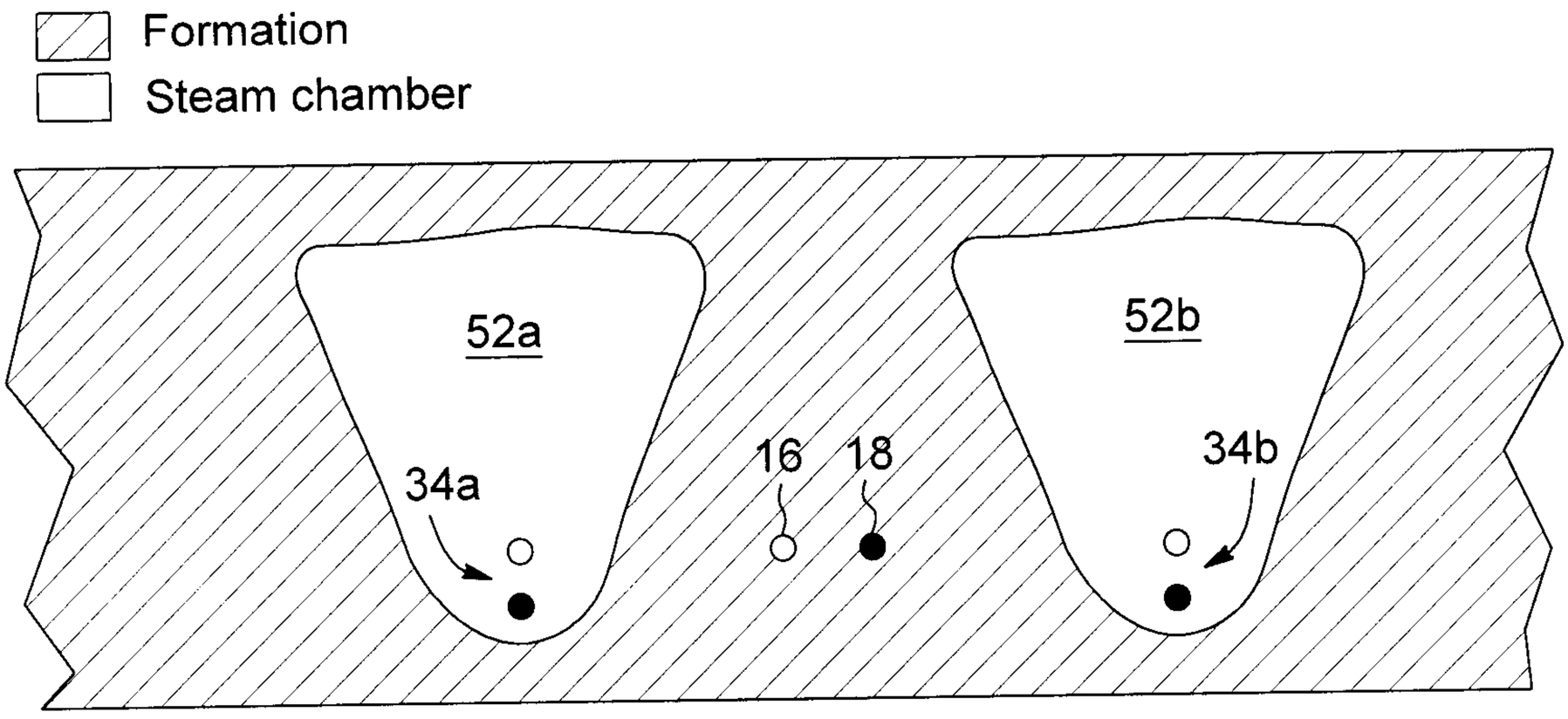


FIG. 3

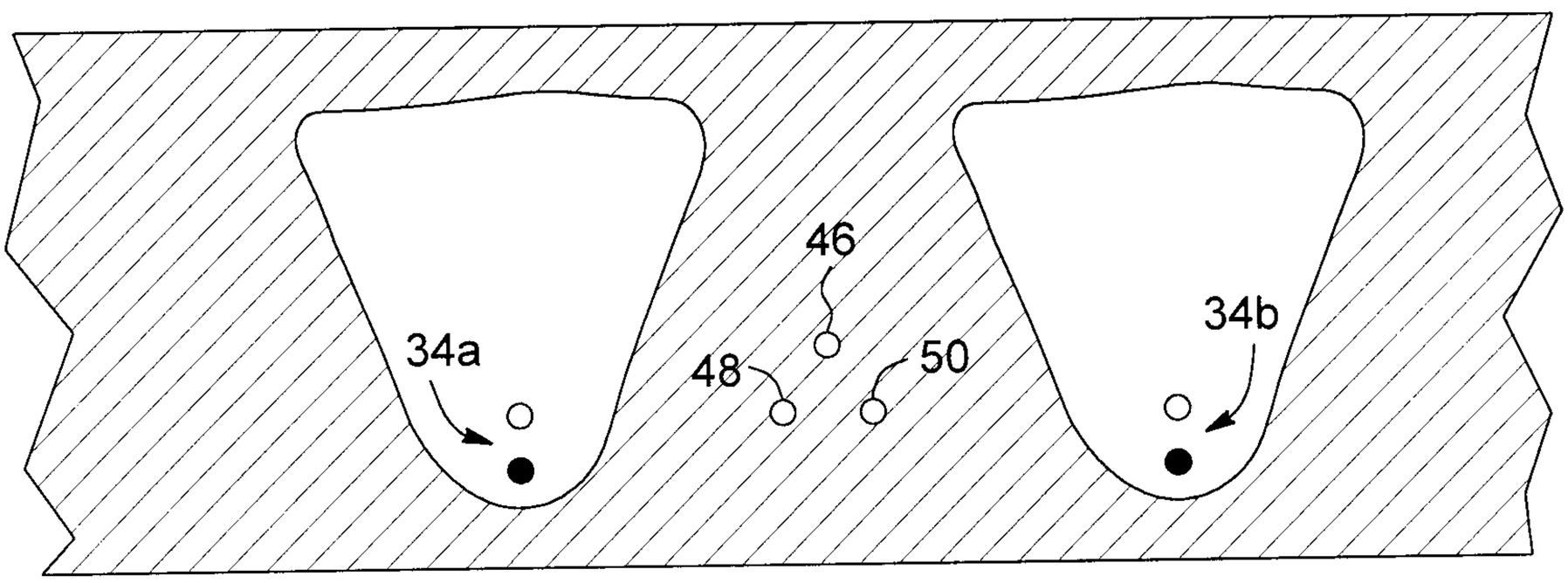


FIG. 4

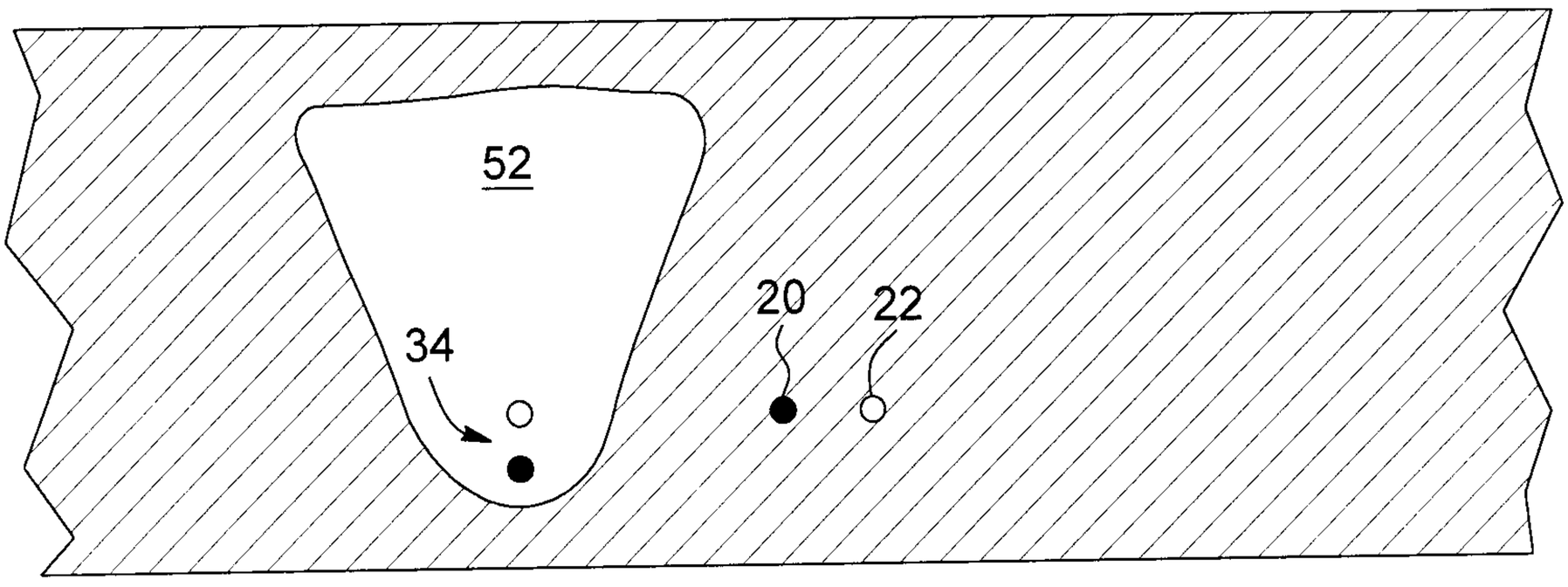


FIG. 5

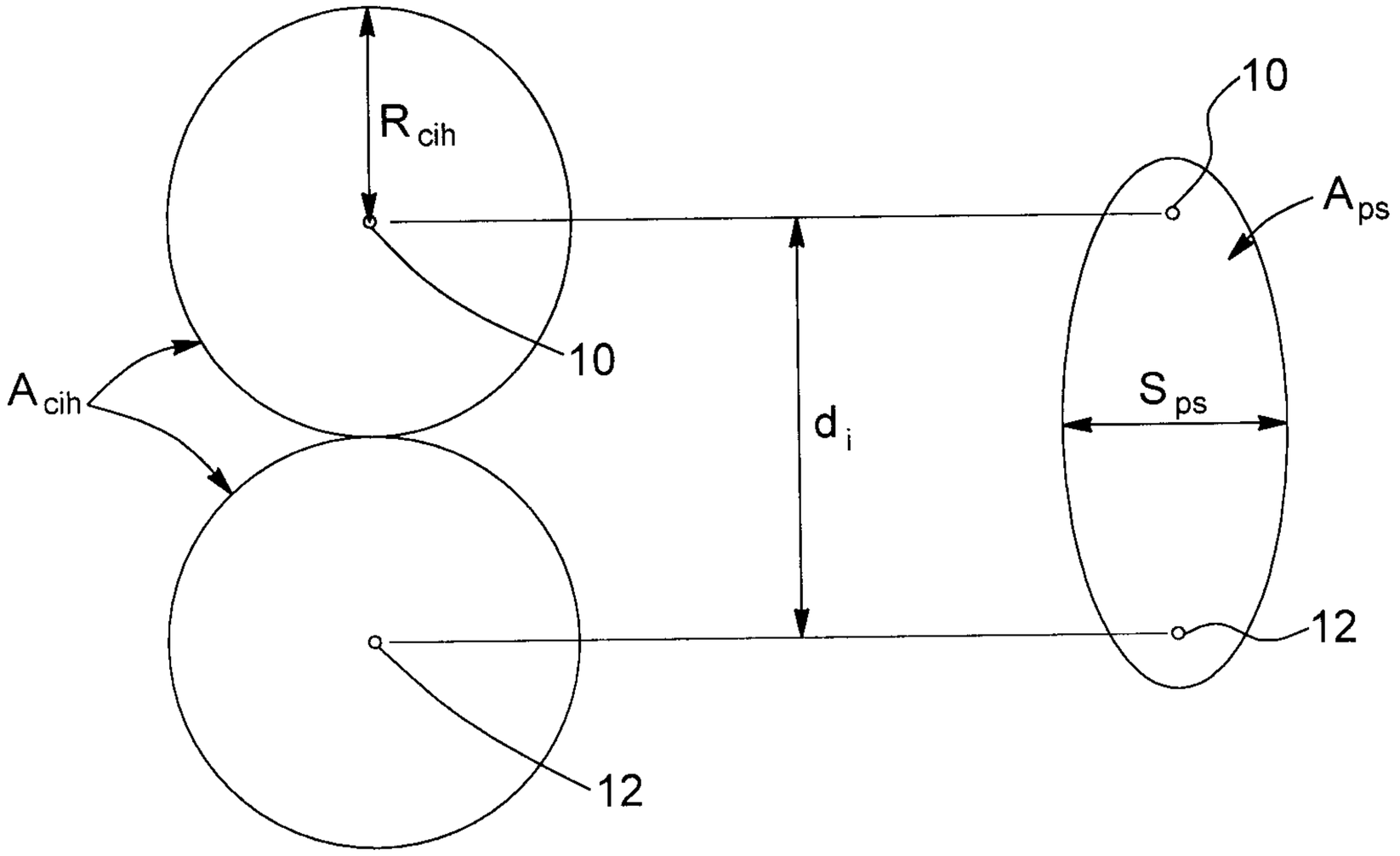


FIG. 6

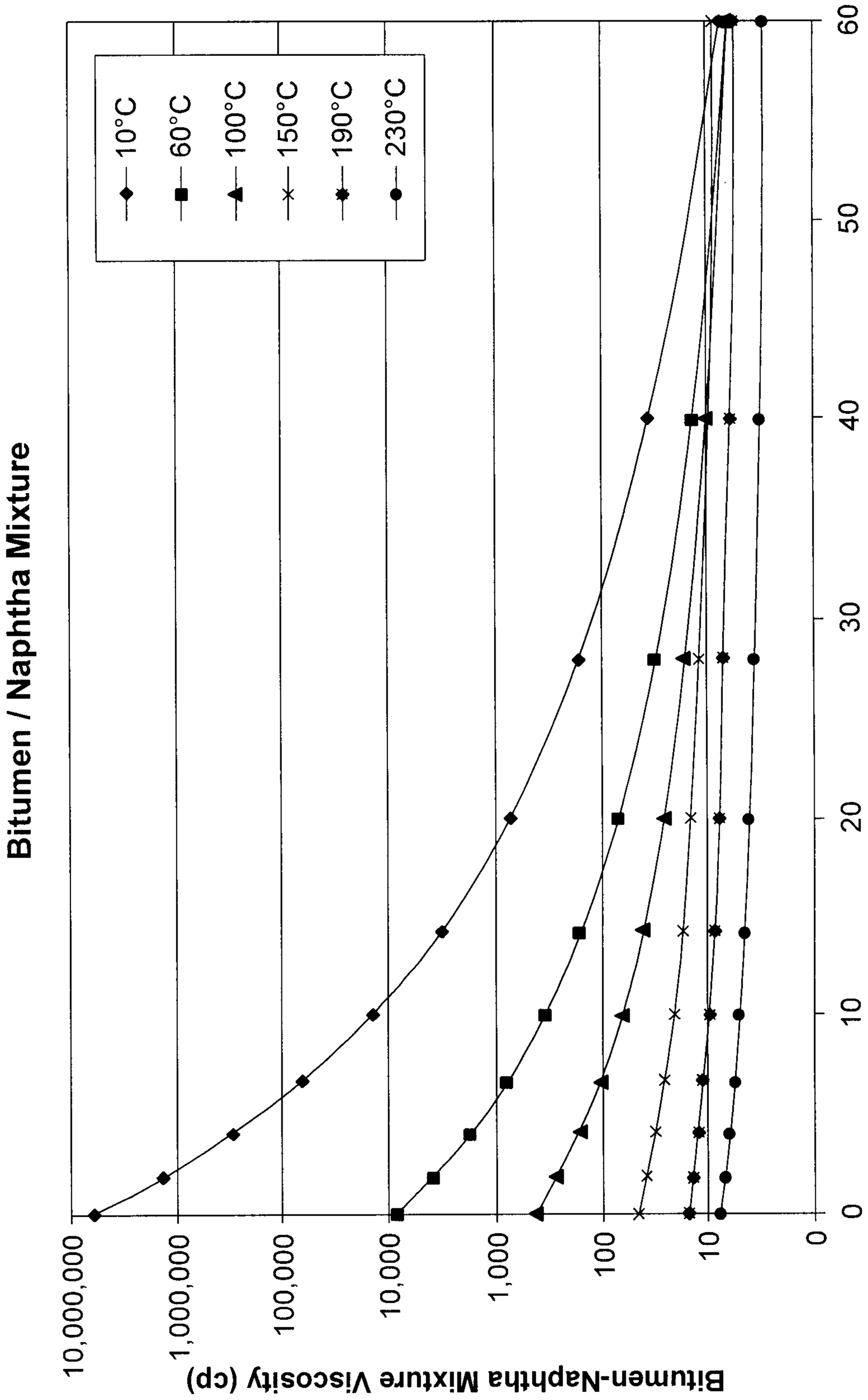

10°C
60°C
100°C
150°C
190°C
230°C
Bitumen / Naphtha Mixture
Naphtha wt%
0
10
20
30
40
50
60
Bitumen-Naphtha Mixture Viscosity (cp)
10,000,000
1,000,000
100,000
10,000
1,000
100
10
0

FIG. 7

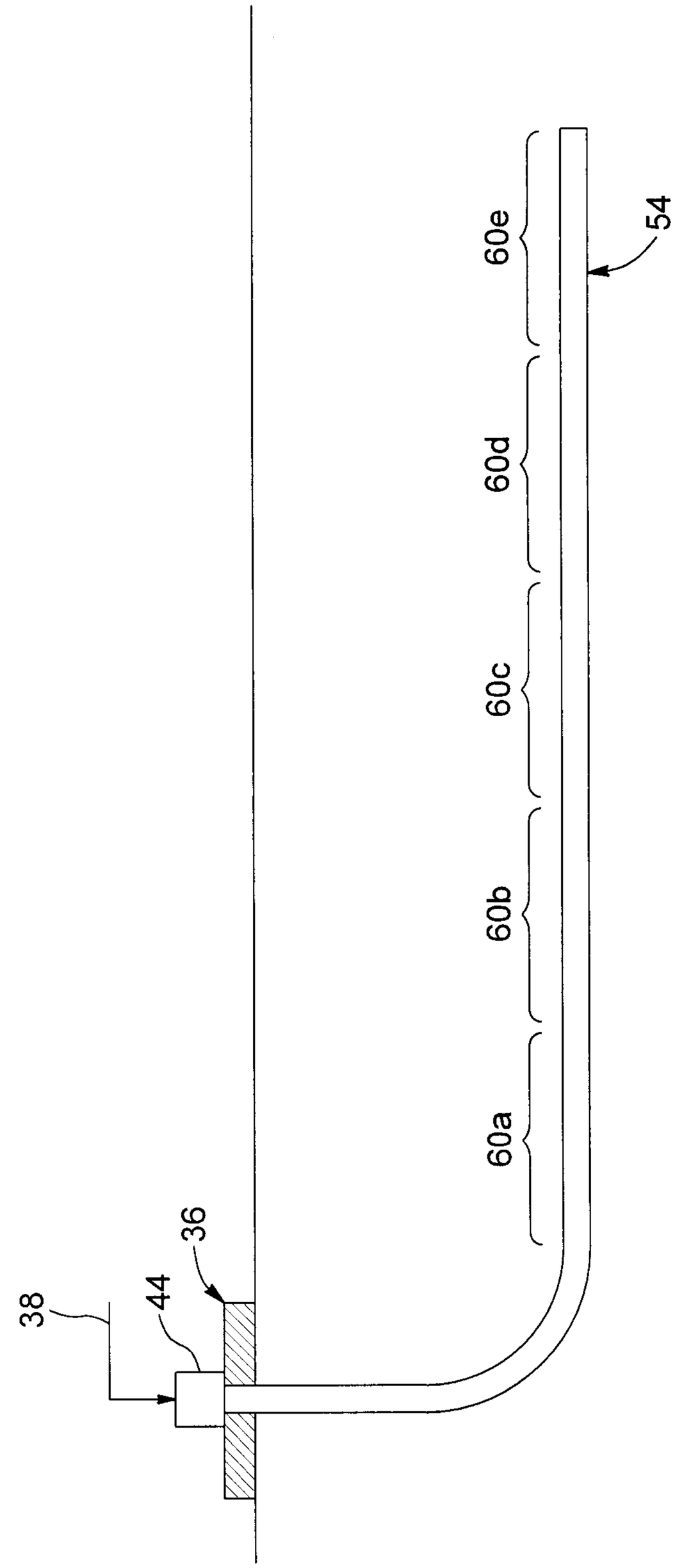


FIG. 8

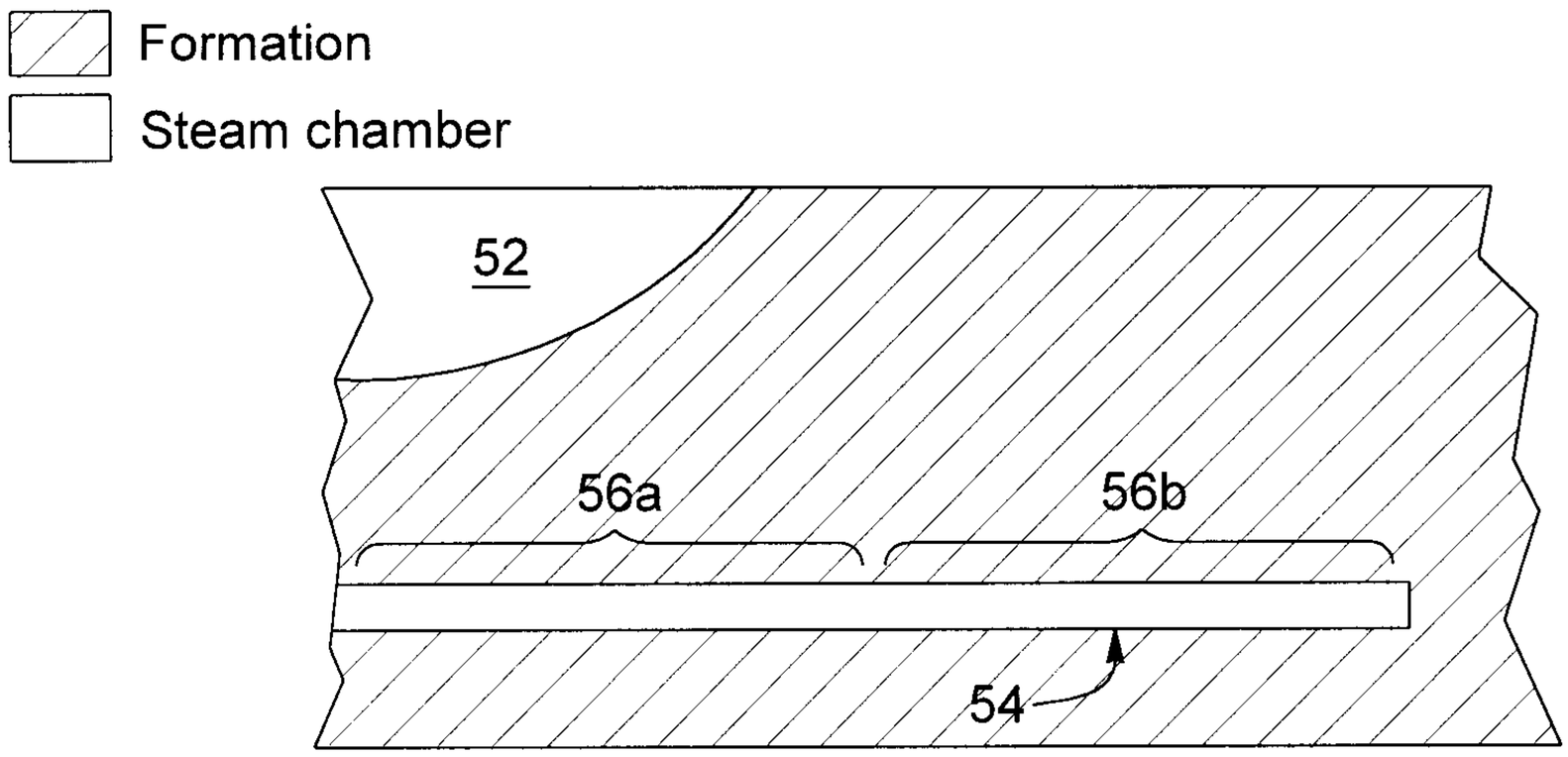


FIG. 9A

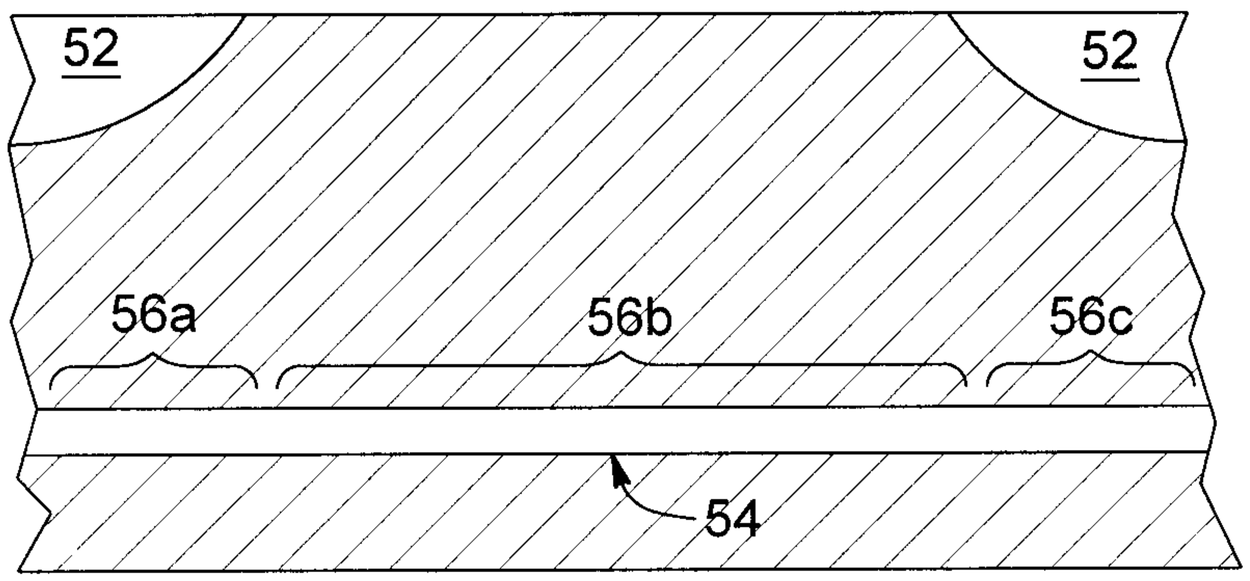


FIG. 9B

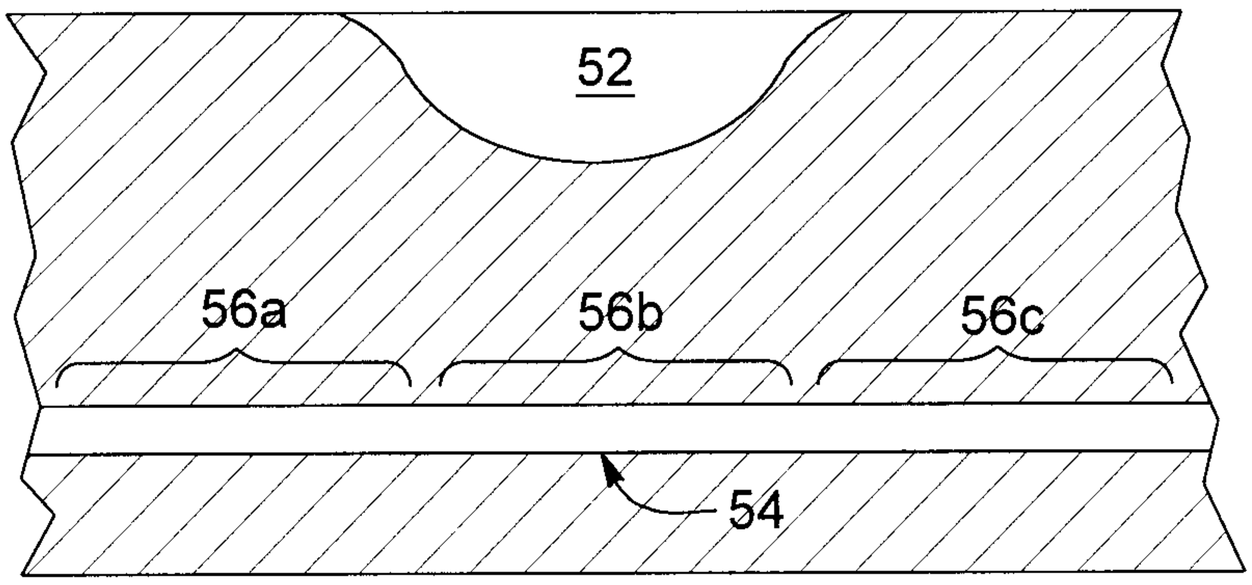


FIG. 9C

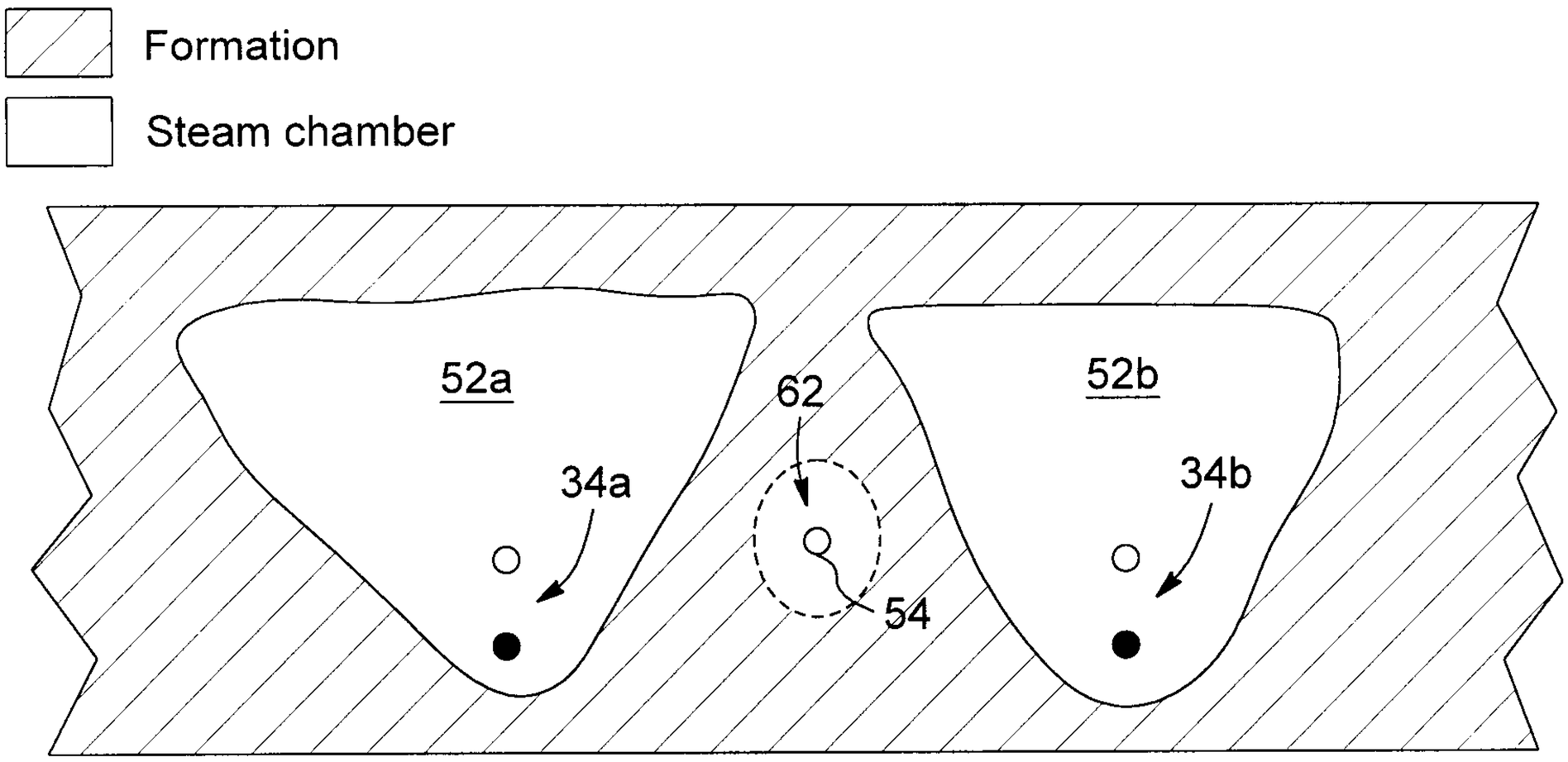


FIG. 10A

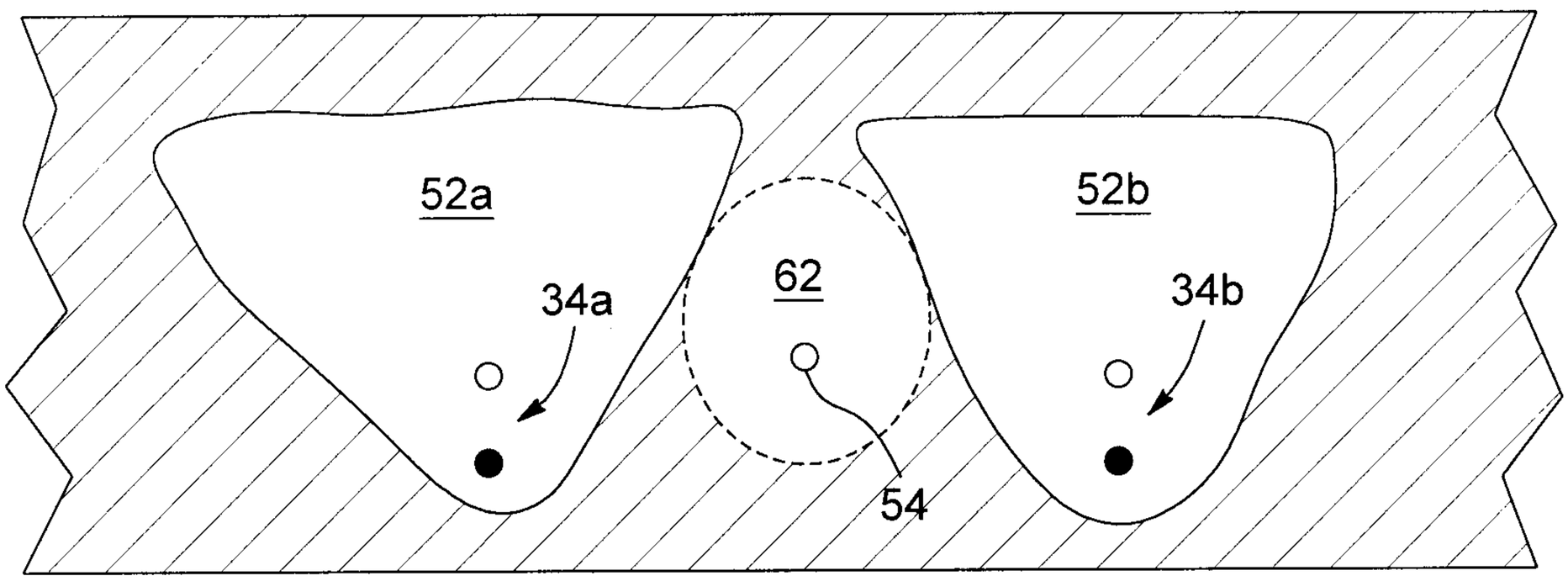


FIG. 10B

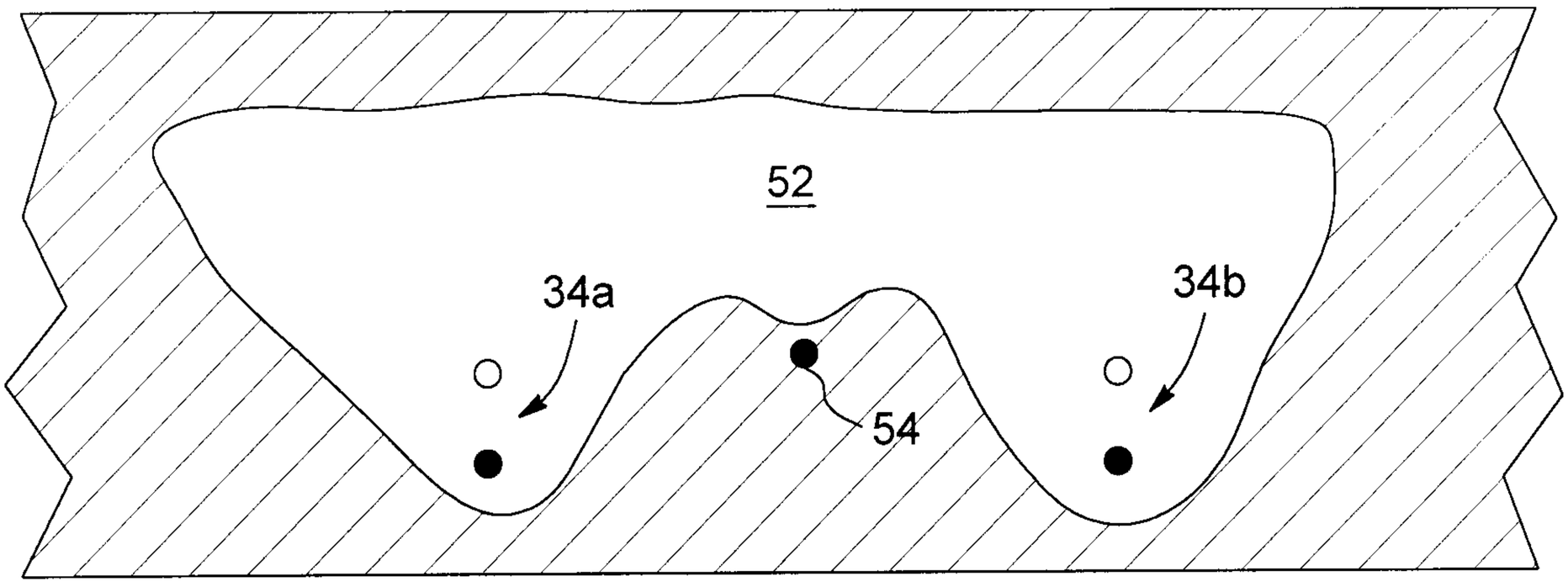


FIG. 10C

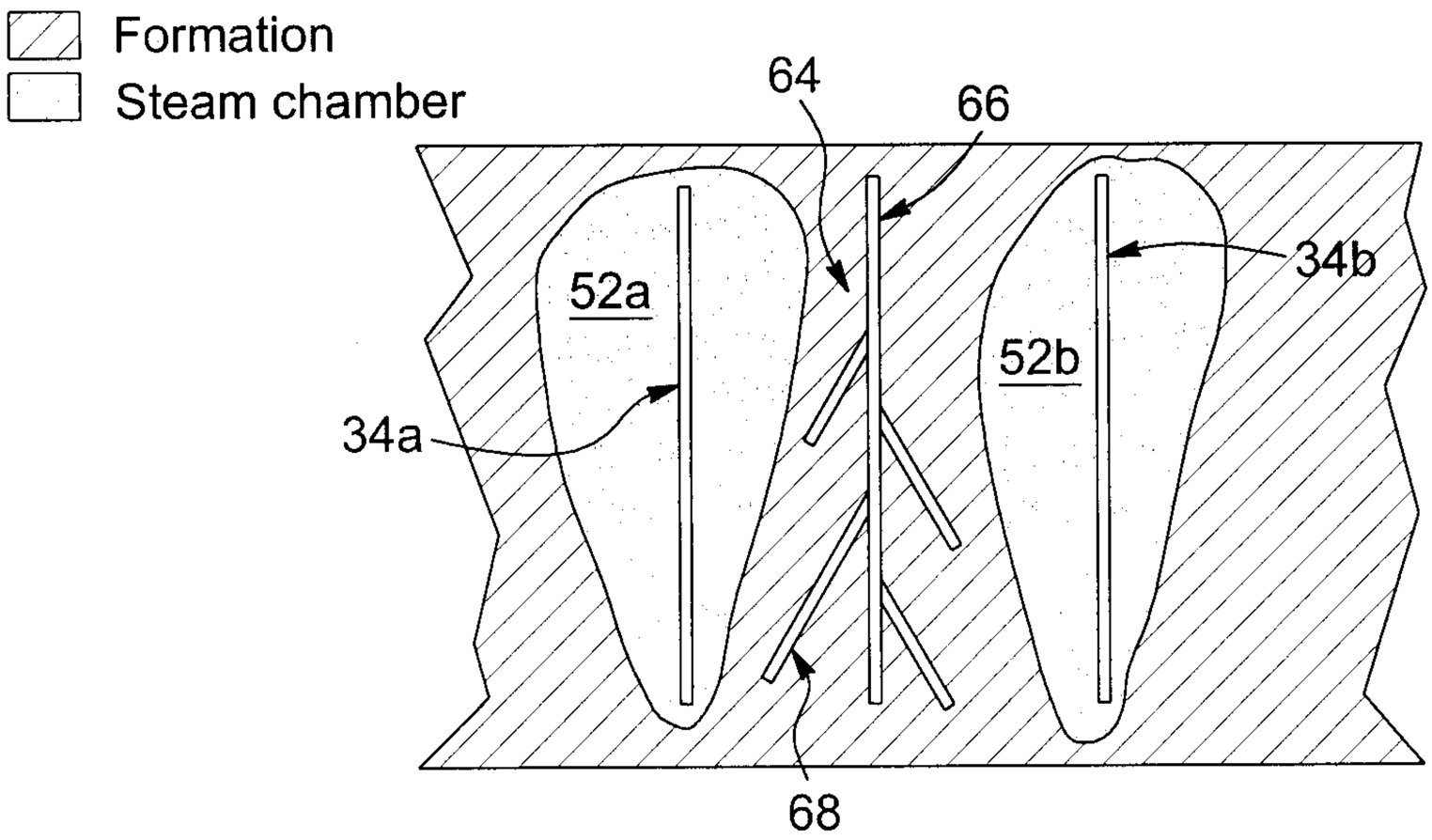


FIG. 11A

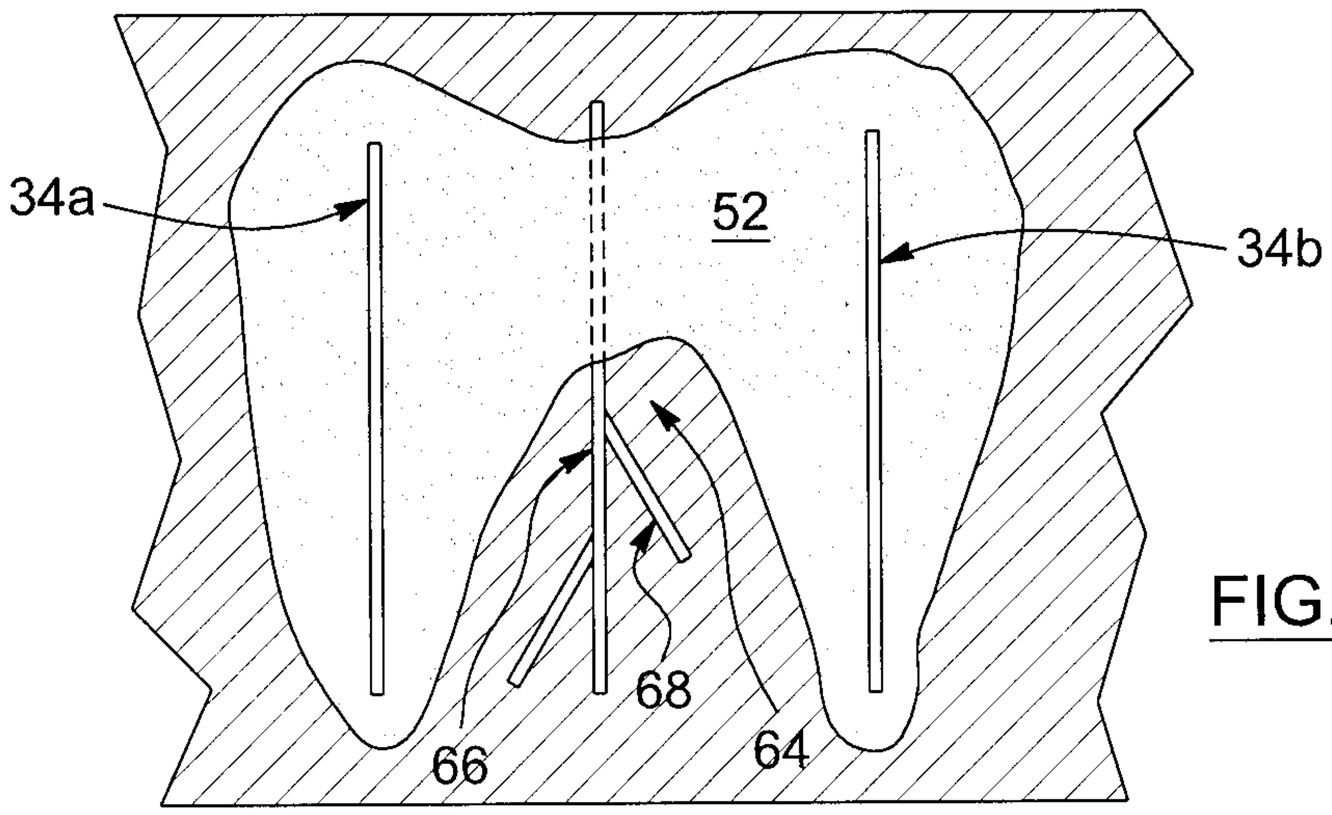


FIG. 11B

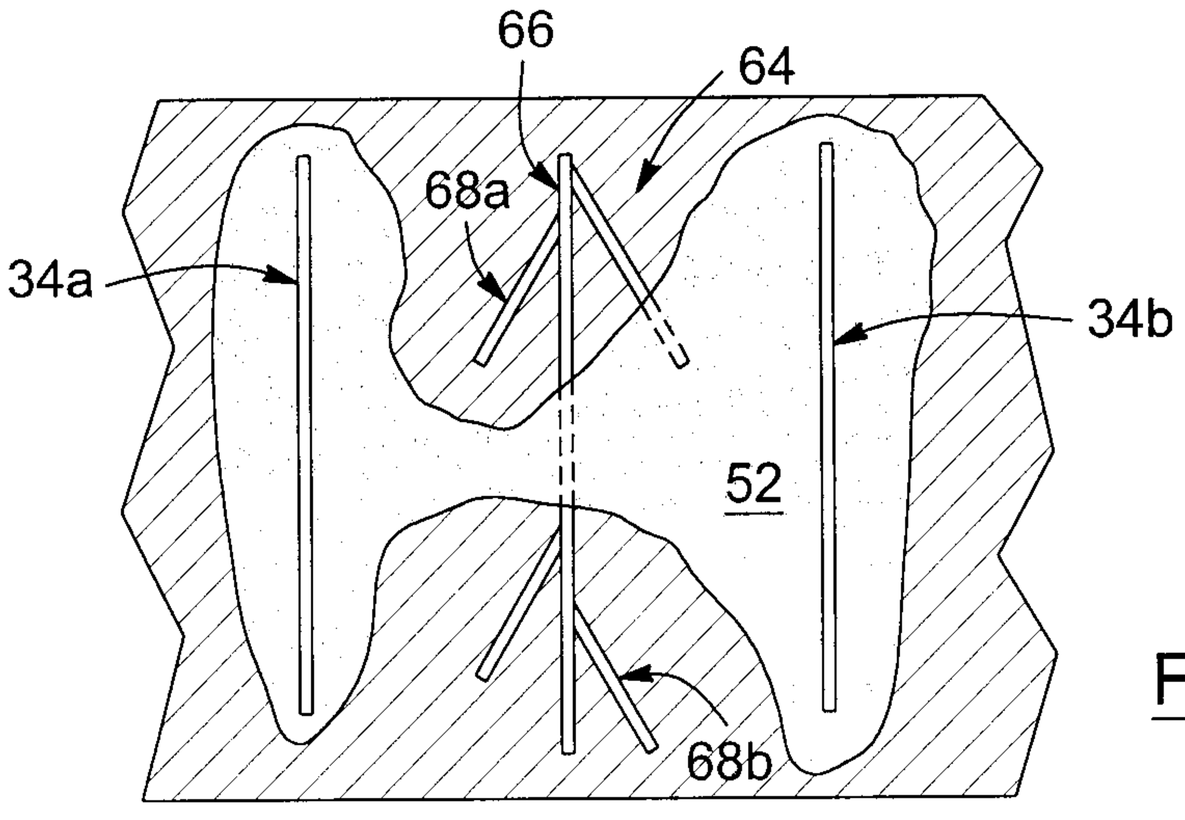
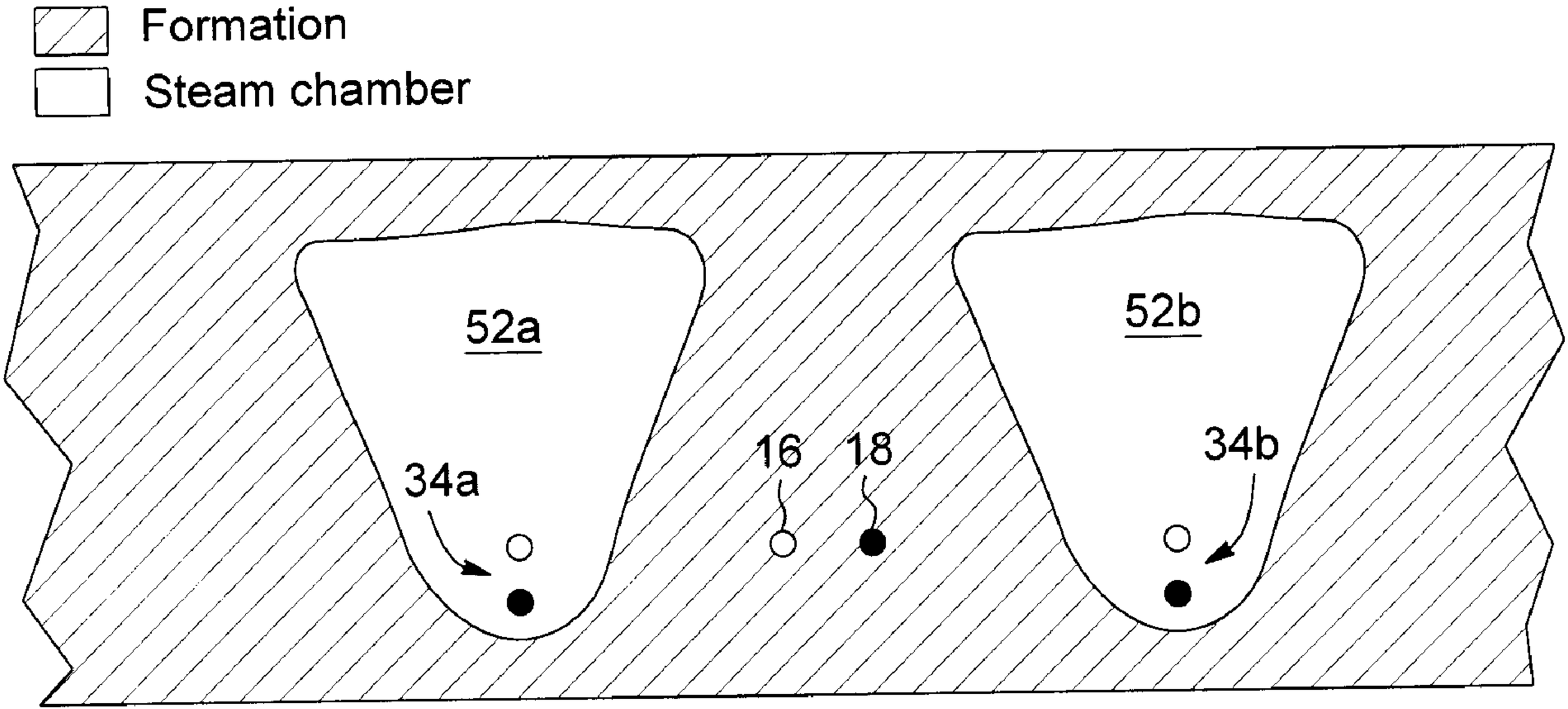


FIG. 11C


Formation
Steam chamber
52a
52b
34a
16
18
34b