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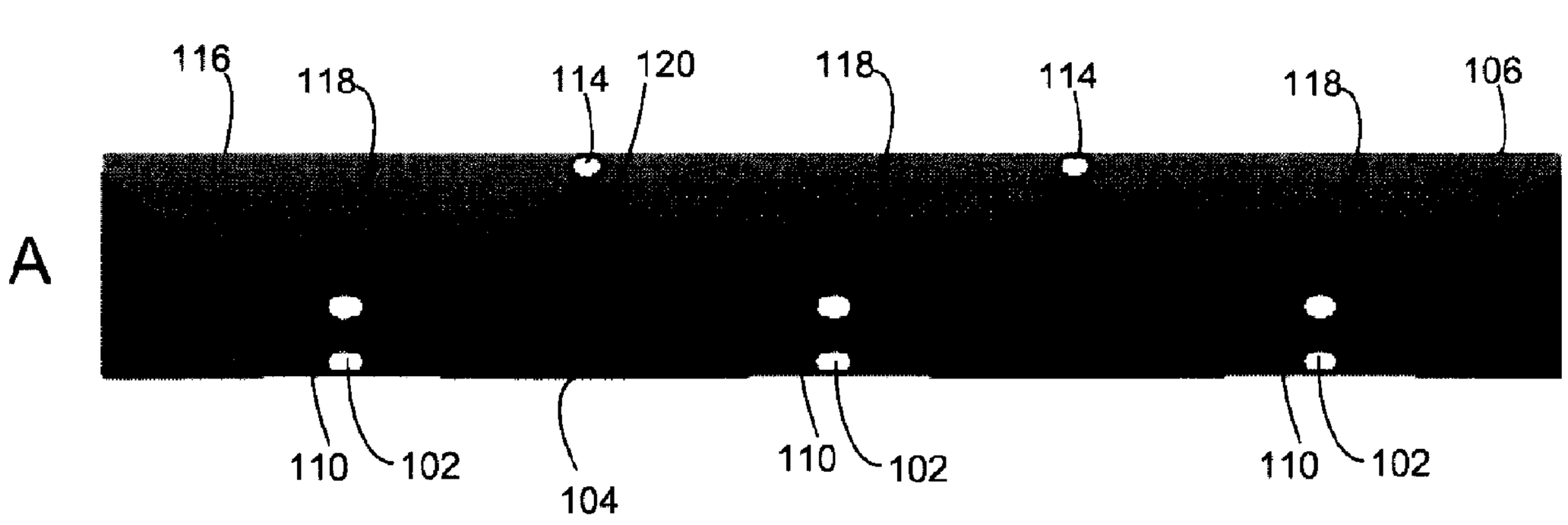
(71) Demandeur/Applicant:
CENOVUS ENERGY INC., CA

(72) Inventeurs/Inventors:
GUPTA, SUBODH, CA;
SOOD, ARUN, CA

(74) Agent: BORDEN LADNER GERVAIS LLP

(54) Titre : PROCEDE DE PRODUCTION D'HYDROCARBURES A PARTIR D'UNE FORMATION RENFERMANT DES HYDROCARBURES SOUTERRAINS

(54) Title: PROCESS FOR PRODUCING HYDROCARBONS FROM A SUBTERRANEAN HYDROCARBON-BEARING FORMATION



(57) Abrégé/Abstract:
A process for recovering hydrocarbons from a hydrocarbon-bearing formation includes injecting steam into injection wells disposed in a lower portion of the hydrocarbon-bearing formation and laterally spaced apart to create respective steam chambers extending upwardly in the hydrocarbon-bearing formation, producing the hydrocarbons from the hydrocarbon-bearing formation, and injecting a solvent through a further well disposed in an upper portion of the hydrocarbon formation, such that a solvent that is cold relative to a steam chamber temperature, is delivered to a location generally between the laterally spaced injection wells in the hydrocarbon-bearing formation and spaced vertically upwardly therefrom.

Abstract

A process for recovering hydrocarbons from a hydrocarbon-bearing formation includes injecting steam into injection wells disposed in a lower portion of the hydrocarbon-bearing formation and laterally spaced apart to create respective steam chambers extending upwardly in the hydrocarbon-bearing formation, producing the hydrocarbons from the hydrocarbon-bearing formation, and injecting a solvent through a further well disposed in an upper portion of the hydrocarbon formation, such that a solvent that is cold relative to a steam chamber temperature, is delivered to a location generally between the laterally spaced injection wells in the hydrocarbon-bearing formation and spaced vertically upwardly therefrom.

PROCESS FOR PRODUCING HYDROCARBONS FROM A SUBTERRANEAN HYDROCARBON-BEARING FORMATION

Technical Field

[0001] The present invention relates to the production of hydrocarbons such as heavy oils and bitumen from a hydrocarbon-bearing formation utilizing steam to mobilize the hydrocarbons.

Background

[0002] Extensive deposits of viscous hydrocarbons exist around the world, including large deposits in the northern Alberta oil sands that are not susceptible to standard oil well production technologies. The hydrocarbons in reservoirs of such deposits are too viscous to flow at commercially relevant rates at the virgin temperatures and pressures present in the reservoir. For such reservoirs, thermal techniques may be utilized to heat the reservoir to mobilize the hydrocarbons and produce the heated, mobilized hydrocarbons from wells. One such technique for utilizing a horizontal well for injecting heated fluids and producing hydrocarbons is described in U.S. Patent No. 4,116,275, which also describes some of the problems associated with the production of mobilized viscous hydrocarbons from horizontal wells.

[0003] One thermal method of recovering viscous hydrocarbons utilizing spaced horizontal wells is known as steam-assisted gravity drainage (SAGD). In general, a SAGD process may be described as including three stages: the start-up stage; the production stage; and the wind-down (or blowdown) stage. The production stage may be described as including further stages such as, for example, a ramp-up stage and a plateau stage.

[0004] In the SAGD process, pressurized steam is delivered through an upper, horizontal, injection well (injector), into a viscous hydrocarbon reservoir while hydrocarbons are produced from a lower, parallel, horizontal, production well (producer) that is near the injection well and is vertically spaced from the injection well. The injection and production wells are situated in the lower portion of the

reservoir, with the producer located close to the base of the hydrocarbon reservoir to collect the hydrocarbons that flow toward the base of the reservoir.

[0005] The SAGD process is believed to work as follows. The injected steam initially mobilizes the hydrocarbons to create a steam chamber in the reservoir around and above the horizontal injection well. The term steam chamber is utilized to refer to the volume of the reservoir that is saturated with injected steam and from which mobilized oil has at least partially drained. As the steam chamber expands, viscous hydrocarbons in the reservoir and water originally present in the reservoir are heated and mobilized and move with aqueous condensate, under the effect of gravity, toward the bottom of the steam chamber. The hydrocarbons, the water originally present, and the aqueous condensate are typically referred to collectively as emulsion. The emulsion accumulates such that the liquid / vapor interface is located below the steam injector and above the producer. The emulsion is collected and produced from the production well. The produced emulsion is separated into dry oil for sales and produced water, comprising the water originally present and the aqueous condensate.

[0006] After peak oil rate production, recovery rates generally decline until the steam to oil ratio no longer supports the injection of steam to mobilize the hydrocarbons. Because the steam chambers expand primarily vertically from the injection wells, unrecovered viscous hydrocarbons that are spaced laterally from the injection wells, are left unmobilized.

[0007] Thermal processes are also extremely energy intensive, utilize significant volumes of water for the production of steam, and may require additional equipment to handle the steam or gasses produced.

[0008] Improvements in recovery of hydrocarbons are desirable.

Summary

[0009] According to an aspect of an embodiment, a process is provided for hydrocarbon recovery from a hydrocarbon-bearing formation. The process includes injecting steam into injection wells disposed in a lower portion of the hydrocarbon-

bearing formation and laterally spaced apart to create respective steam chambers extending upwardly in the hydrocarbon-bearing formation, producing the hydrocarbons from the hydrocarbon-bearing formation, and injecting a solvent through a further well disposed in an upper portion of the hydrocarbon formation, such that a solvent that is cold relative to a steam chamber temperature, is delivered to a location generally between the laterally spaced injection wells in the hydrocarbon-bearing formation and spaced vertically upwardly therefrom.

[0010] According to another aspect of an embodiment, a process is provided for recovering hydrocarbons from a hydrocarbon-bearing formation having injection and production well pairs extending into a lower portion of the hydrocarbon-bearing formation, the injection and production well pairs being laterally spaced apart within the hydrocarbon-bearing formation. The process includes injecting steam into the injection wells and producing hydrocarbons utilizing the production wells, thereby forming respective steam chambers extending into the hydrocarbon bearing formation from the injection wells, and, after coalescence of steam chambers of adjacent injection and production well pairs, injecting a liquid solvent through a solvent injection well disposed in an upper portion of the hydrocarbon formation, to deliver liquid solvent to a location generally between the adjacent injection and production well pairs in the hydrocarbon-bearing formation.

[0011] The solvent injection well and the steam chamber(s) are in fluid communication prior to solvent injection to facilitate movement of the solvent into the chamber(s). Absent this fluid communication, i.e., when the hydrocarbon-bearing formation between the solvent injection well and the chamber(s) is at a relatively low temperature (has not been warmed), the cold solvent has very low or practically no mobility and may not reach the steam chamber(s). Thus, for the flow of solvent through the reservoir, some heat is present in the hydrocarbons, even if the steam chambers (the depleted zones) have not actually enveloped the solvent injection well.

[0012] The solvent may be injected at ambient temperature at the wellhead. The solvent may also be injected at sub-fracturing pressure and flow rate. Injecting steam and producing the hydrocarbons may be carried out in a steam-

assisted gravity drainage (SAGD) process or a solvent-aided process (SAP). The solvent injected through the further well may be any solvent having 2 to 8 carbon atoms per molecule, such as propane. A non-condensable gas, such as methane or carbon dioxide, may be injected along with the solvent. The proportion of non-condensable gas to solvent injected may increase over time. The volume of steam injected may decrease as the volume of non-condensable gas increases.

[0013] The injection of solvent may be carried out after coalescence of adjacent ones of the steam chambers, i.e., one of the steam chambers adjacent to another one of the steam chambers, and the process may optionally include determining that adjacent ones of the steam chambers have coalesced prior to injecting solvent, and injecting the solvent is carried out in response to coalescence of the adjacent ones of the steam chambers. The solvent may be continually injected until the blowdown stage.

[0014] Optionally, the further well may be configured to deliver solvent to at least two locations between laterally spaced injection wells and spaced vertically upwardly therefrom, including the location between a first injection well and a second injection well, and a second location, between the second injection well and a third injection well. For example, the further well may include a horizontal section that extends in a direction generally transverse to that of the injection wells. Flow control devices may be utilized in the further well to control the flow of solvent to a plurality of locations generally between laterally spaced injection wells, including the location between a first injection well and a second injection well, and a second location, between the second injection well and a third injection well.

Brief Description of the Drawings

[0015] Embodiments of the present invention will be described, by way of example, with reference to the drawings and to the following description, in which:

[0016] FIG. 1A is a schematic sectional view through a reservoir, illustrating horizontal segments of injection and production wells utilized in a hydrocarbon recovery process in accordance with one example of the present invention;

[0017] FIG. 1B is a schematic sectional view through a reservoir, illustrating horizontal segments of injection and production wells utilized in a hydrocarbon recovery process in accordance with another example of the present invention;

[0018] FIG. 2 is a flowchart illustrating a method of recovering hydrocarbons from a hydrocarbon bearing formation, in accordance with the present invention;

[0019] FIG. 3 is a simulation diagram illustrating the extent of steam chamber development during SAGD in the first 3 years of the hydrocarbon recovery process;

[0020] FIG. 4 is a simulation diagram illustrating spread of propane within the oleic phase in the reservoir at the end of 60 days of injection according to the process of FIG. 2;

[0021] FIG. 5 is a simulation diagram illustrating pressure gradients in the steam chamber in accordance with the process of FIG. 2;

[0022] FIG. 6 is a graph illustrating the oil production rate in SAGD compared to the oil production rate utilizing the process of FIG. 2 (referred to as a cold solvent process);

[0023] FIG. 7 is a graph showing steam (BBL/day), propane (tonnes/day) and methane (tonnes/day) injection rates over time utilizing the process of FIG. 2;

[0024] FIG. 8 is a graph showing cumulative oil recovery for SAGD and for the process of FIG. 2;

[0025] FIG. 9 is a graph showing the energy equivalent cumulative steam to oil ratio (eCSOR) for the process of FIG. 2 and SAGD;

[0026] FIG. 10 is a graph illustrating propane injected into the solvent injection well and propane produced through the production well utilizing the process of FIG. 2;

[0027] FIG. 11 is a graph illustrating production rates for SAGD, fixed rate propane injection with steam injection, and propane injection with no steam injection;

[0028] FIG. 12 is a graph showing the energy equivalent cumulative steam to oil ratio (eCSOR) for SAGD, fixed rate propane injection with steam injection, and propane injection with no steam injection; and

[0029] FIG. 13 is a graph showing percentage of total oil in place recovered for SAGD, fixed rate propane injection with steam injection, and propane injection with no steam injection.

Detailed Description

[0030] For simplicity and clarity of illustration, reference numerals may be repeated among the figures to indicate corresponding or analogous elements. Numerous details are set forth to provide an understanding of the examples described herein. The examples may be practiced without these details. In other instances, well-known methods, procedures, and components are not described in detail to avoid obscuring the examples described. The description is not to be considered as limited to the scope of the examples described herein.

[0031] The disclosure generally relates to a process for hydrocarbon recovery from a hydrocarbon-bearing formation. The process includes injecting steam into injection wells disposed in a lower portion of the hydrocarbon-bearing formation, the wells being laterally spaced apart to create respective steam chambers extending upwardly in the hydrocarbon-bearing formation, producing the hydrocarbons from the hydrocarbon-bearing formation, and injecting a solvent through a further well disposed in an upper portion of the hydrocarbon formation, such that a solvent that is cold relative to a steam chamber temperature, is delivered to a location generally between the laterally spaced injection wells in the hydrocarbon-bearing formation and spaced vertically upwardly therefrom.

[0032] As noted above, the present disclosure relates to the injection of a mobilizing and displacing fluid, such as steam. In the present example, the process is described in relation to SAGD. The present process may be successfully implemented with other processes that utilize steam, however.

[0033] In the SAGD process, well pairs, each including a hydrocarbon production well and a steam injection well are utilized. A hydrocarbon production well includes a generally horizontal segment that extends near the base or bottom of the hydrocarbon reservoir. The injection well also includes a generally horizontal segment that is disposed generally parallel to and is spaced generally vertically above the horizontal segment of the hydrocarbon production well.

[0034] During SAGD, steam is injected into the injection well to mobilize the hydrocarbons and create a steam chamber in the reservoir, around and above the generally horizontal segment of the injection well. In addition to steam injection into the steam injection well, light hydrocarbons, such as C3 through C10 alkanes, either individually or in combination, may optionally be injected with the steam such that the light hydrocarbons function as solvents in aiding the mobilization of the hydrocarbons. The volume of light hydrocarbons injected is relatively small compared to the volume of steam injected, for example, up to about 20 wt% solvent. The addition of light hydrocarbons is referred to as a solvent aided process (SAP). Alternatively, or in addition to the light hydrocarbons, various non-condensing gases, such as methane or carbon dioxide, may be injected. Viscous hydrocarbons in the reservoir are heated and mobilized and the mobilized hydrocarbons drain under the effect of gravity. Fluids, including the mobilized hydrocarbons along with connate water and condensed steam (aqueous condensate), are collected in the generally horizontal segment of the production well. The fluids may also include gases such as steam, solvent, and production gases (e.g., methane, hydrogen sulfide) from the SAGD process or a SAP.

[0035] A simplified schematic section view illustrating horizontal segments of injection and production wells utilized in a hydrocarbon recovery process in accordance with one example is shown in FIG. 1A. In the example of FIG. 1A, three pairs of injection and production wells are illustrated. Each of the production wells 102 includes a generally horizontal segment that extends near the base or bottom 104 of the hydrocarbon reservoir 106. Each steam injection well 110 also includes a generally horizontal segment that is disposed generally parallel to and is spaced generally vertically above the horizontal segment of the hydrocarbon

production well 102. In addition to the steam injection wells 110, solvent injection wells 114 are also utilized.

[0036] The horizontal segment of the solvent injection well 114 in the example of FIG. 1A is located generally equidistant from two adjacent well pairs. The solvent injection well 114 is drilled such that at least a portion of the horizontal segment is located near the top 116 of the reservoir 106. The adjacent steam chambers 118 that are created by the injection of the steam through the steam injection wells 110 typically merge near the top 116 of the reservoir 106, with unmobilized hydrocarbons 120 disposed between the adjacent well pairs. Alternatively, the solvent injection well 114 may be at a location other than generally equidistant and near the top of the reservoir. For example, the solvent injection well may be positioned further below the top of the reservoir, between the two well pairs, in an area that is sufficiently mobilized, i.e., sufficiently heated from the SAGD process, to allow for solvent injection to facilitate the mobilizing of hydrocarbons. Absent sufficient heating of the reservoir where the solvent is injected, the cold solvent has very low or practically no mobility and may not reach the steam chambers.

[0037] After adjacent steam chambers 118 merge, solvent is injected through the solvent injection well 114 to deliver solvent to unmobilized hydrocarbons 120 disposed near the top 116 of the reservoir 106 and laterally between injection and production well pairs. The solvent is injected at a temperature that is less than the temperature in the steam chamber. For example, the solvent may be injected at ambient temperatures at the wellhead, thus facilitating injection of solvent absent heating, even in temperatures in cold winter climates such as those in Northern Alberta. The solvent is delivered to the location near the top 116 of the reservoir 106 and generally between the laterally spaced injection and production well pairs at a temperature that is lower than that of the steam chamber temperature. The solvent is injected at sub-fracturing pressure and flowrate. The solvent may be injected at any suitable rate. The solvent injection rate may be from a rate of gas produced from the steam chambers up to a rate sufficient to maintain pressure in the steam chambers. The solvent injection rate may be dependent on reservoir

depth, heat present in the chambers, and volume in the chambers for the solvent to occupy. Generally, the rate of solvent injection is much less than the steam injection rate prior to the start of solvent injection.

[0038] The solvent may be any suitable solvent, including light hydrocarbons such as alkanes. Solvents having 2 to 8 carbon atoms per molecule, such as ethane, propane, butane, pentane, hexane, heptane, or octane may be utilized.

[0039] The solvent injection as described herein is independent of the steam injection infrastructure. The solvent may be delivered in the liquid state to the location generally between the adjacent injection and production well pairs. Thus, the solvent may be injected, for example, directly from a truck or a vessel, into the solvent injection well without pre-heating.

[0040] Once inside the steam chamber, liquid solvent absorbs latent heat from the reservoir 106 and achieves thermodynamic equilibrium with a portion of the solvent dissolving in the oleic phase in the reservoir and the remainder of the solvent vaporizing. Utilizing the solvent injection well 114, the solvent is delivered directly to the outer edges of the steam chamber where the solvent is most beneficial.

[0041] The solvent that vaporizes facilitates maintaining the steam chamber pressure and exerts a back pressure on the steam injection. The steam injection rate may be decreased to maintain the operating pressure, eventually resulting in reduced steam injection.

[0042] Liquid solvent injection utilizing a solvent injection well 114 as described reduces steam injection rates while assisting in maintaining the steam chamber pressure. The reduction in steam injection rate is related to the rate at which solvent is injected. This correlation between solvent and steam injection rates may be used advantageously to reduce the steam utilized in older wells and facilitate the diversion of steam to newer wells that are starting up. Thus, increased oil production rates may be realized without additional steam generation capacity.

[0043] In a SAGD implementation, well pairs may be spaced about 50 meters to about 125 meters apart. In some examples, well pairs may be spaced about 80 meters to 100 meters apart. Steam chambers from adjacent well pairs may merge after 3 to 4 years of operation. Reservoirs are heterogeneous, however, and high permeability or preferential flow channels may exist that result in steam chambers spreading laterally at a faster rate. In such situations, adjacent steam chambers may merge much more quickly, facilitating relatively cold solvent injection at an earlier time, i.e., before 3 to 4 years of production.

[0044] Solvent solubility in bitumen is inversely proportional to temperature. The injection of relatively cold solvent into the steam chamber utilizing the solvent injection wells enhances solubility of the solvent in bitumen and improves recovery compared to conventional SAGD or solvent-aided processes. Utilizing the present method, sufficient energy is already present in the reservoir to vaporize and distribute a portion of the solvent within the steam chamber. Thus, energy already present in the steam chamber is utilized as the injected solvent is cold by comparison to the steam chamber. The injected solvent therefore heats up while cooling the steam chamber.

[0045] Dissolution of solvent in bitumen reduces the viscosity and enhances mobility of the oleic phase. A gradual increase in oil production rate may be observed subsequent to commencement of solvent injection. Over time, a secondary peak oil production rate is achieved, which is comparable to the first peak observed with steam prior to the merging of adjacent steam chambers. After the secondary peak oil production rate is achieved, a non-condensable gas is optionally co-injected with the relatively cold solvent. Methane and carbon dioxide are generally inexpensive or readily available non-condensable gases. Thus, the non-condensable gas may be methane or carbon dioxide. Other non-condensable gases such as air, nitrogen, or natural gas may alternatively or additionally be utilized.

[0046] The proportion of the non-condensable gas injected relative to solvent may increase gradually over time. Because the non-condensable gas remains primarily in vapor phase, the increased proportion of non-condensable gas to

solvent increasingly impacts the pressure in the merged steam chambers and leads to progressively lower steam injection rates. Steam injection is eventually stopped and the blowdown stage is commenced.

[0047] In the above-described example, the solvent is injected through the solvent injection well 114 after merging of adjacent steam chambers. The present process may also be implemented in mature wells that are slated for blowdown. For example, steam injection may be discontinued and relatively cold solvent injected via a solvent injection well. Oil production may increase, leading to a secondary peak oil rate. Subsequently, non-condensable gas, such as methane, may be injected with increasing volume in proportion to the volume of solvent injected, as described above. Eventually, the solvent injection is stopped and the blowdown stage is commenced.

[0048] A flowchart illustrating a process of recovering hydrocarbons from a hydrocarbon bearing formation is illustrated in FIG. 2. The process may contain additional or fewer subprocesses than shown or described, and parts of the process may be performed in a different order.

[0049] As described above, steam is injected via steam injection wells that are generally laterally spaced apart within a reservoir at 202. Hydrocarbons are produced, along with connate water and condensed steam (aqueous condensate), utilizing production wells at 204. The horizontal segments of the injection and the production well pairs are generally located in a lower portion of the hydrocarbon-bearing formation, i.e., closer to a base than the top of the hydrocarbon-bearing formation, as illustrated for example in FIG. 1A.

[0050] Reference is made herein to injection and production well pairs. The injection well and the production well may be physically separate wells. Alternatively, the production well and the injection well may be housed, at least partially, in a single physical wellbore, for example, a multilateral well. The production well and the injection well may be functionally independent components that are hydraulically isolated from each other, and housed within a single physical wellbore.

[0051] After merging of adjacent steam chambers at 206, which steam chambers are created by the injection of steam through the steam injection wells, the process continues at 208. The steam chamber growth may be monitored or communication between steam chambers tested and, in response to determining that the steam chambers have coalesced, the process continues at 208. Alternatively, the process may continue at 208 after injection of steam into the steam injection wells for a period of time sufficient to cause coalescence of the adjacent steam chambers.

[0052] The solvent injection well and the steam chambers are also in fluid communication prior to solvent injection at 208 to facilitate movement of the solvent into the chambers. Absent this fluid communication, i.e., when the hydrocarbon-bearing formation between the solvent injection well and the chambers is at a relatively low temperature (has not been warmed), the cold solvent has very low or practically no mobility and may not reach the steam chambers. Thus, for the flow of solvent through the reservoir, some heat is present in the hydrocarbons, even if the steam chambers (the depleted zones) have not actually enveloped the solvent injection well.

[0053] The solvent is injected via the solvent injection well at 208 and a secondary peak oil production rate is achieved. The solvent may be any suitable solvent as described above. After the secondary peak oil production rate is achieved, the non-condensable gas such as methane or carbon dioxide is optionally co-injected with the relatively cold solvent through the solvent injection well at 210. The proportion of the non-condensable gas injected relative to solvent may increase gradually over time. As shown at 212, the rate of steam injection is decreased over time as the relatively cold solvent is injected and the optional non-condensable gas is injected.

[0054] In an alternative example, steam injection is discontinued completely upon commencement of injecting the liquid solvent and non-condensable gas. The liquid solvent and non-condensable gas in this example, is injected at a rate sufficient to maintain the pressure in the steam chamber by the methane and vaporized solvent. Operation of the production well at its original gas production

rate continues. This alternative example utilizes more solvent than the example described above, but higher production rates may be realized. As more heat is removed quickly from the steam chamber to vaporize the liquid solvent, faster cooling of the steam chamber occurs, enhancing solubility of solvent in the oleic phase. The proportion of non-condensable gas to solvent injected may be increased over time. After reaching a certain recovery of hydrocarbons from the reservoir, solvent injection may be completely stopped and blowdown commenced.

[0055] Pressure gradients may be manipulated within the steam chamber by opening and closing steam injection ports utilizing flow control devices. The pressure gradients may be manipulated to preferentially sweep the solvent vapor to target locations based on steam chamber development.

[0056] In the example shown in FIG. 1A, a separate solvent injection well is included between each two adjacent well pairs. Rather than separate solvent injection wells between each pair of adjacent well pairs, a single solvent injection well may be utilized to deliver solvent to locations between more than two well pairs. Referring to FIG. 1B, a single solvent injection well 130 is illustrated. The single solvent injection well 130 includes a generally horizontal segment located near the top of the reservoir. In the present example, however, the generally horizontal segment of the solvent injection well 130 extends in a direction that is generally transverse to the generally horizontal segments of the steam injection wells 110 and the production wells 102. Flow control devices along the solvent injection well 130 are employed to control the flow of solvent to deliver the relatively cold solvent to locations between more than one pair of adjacent injection wells 110. Optionally, one or more additional solvent injection wells may be utilized such that each of the one or more additional solvent injection wells deliver solvent to further locations between more than two well pairs. Utilizing the flow control devices, the solvent may be injected to selected locations to deliver solvent to selected steam chambers, for example, to deliver solvent to adjacent steam chambers that have coalesced without waiting for other pairs of steam chambers to coalesce.

[0057] In the examples shown in FIG. 1A and FIG. 1B, three pairs of injection and production wells are illustrated. The present process may be applied to a single injection and production well pair. In this example, a solvent injection well may be disposed near a side of a steam chamber for delivery of relatively cold solvent near a steam chamber side. Solvent may also be delivered to other sides of the steam chamber.

[0058] Alternatively, a multilateral solvent injection well may be a multilateral well for the injection of solvent to multiple locations between well pairs. In yet another alternative, the multilateral solvent injection well may be a vertical well for delivering solvent to multiple locations between well pairs. The solvent injection well may be a well previously utilized as an observation well and recompleted as a vertical injector for injection of solvent.

[0059] One example of a vertical well that may be successfully utilized in the present process is shown and described in Canadian patent application number 2,937,710, entitled Vertical Staging With Horizontal Production in Heavy Oil Extraction, assigned to Cenovus Energy, Inc. Such a vertical injection well may be utilized for solvent injection at any suitable vertical location along the vertical injection well. The ability to select a location along the vertical injection well facilitates solvent injection and resulting hydrocarbon recovery in complex geologies.

[0060] Advantageously, solvent at a temperature that is lower than that of the steam chamber is injected via a solvent injection well as described herein, after the coalescence of adjacent steam chambers, and facilitates the absorption of latent heat from the reservoir by the solvent to vaporize the solvent. The solvent may be injected at ambient temperature at the wellhead, facilitating injection of solvent absent heating, even in temperatures in cold winter climates such as those in Northern Alberta. The pressure gradients in the steam chamber facilitate solvent spreading along the outer edge of the steam chamber. This can be achieved with or without continued steam injection as the solvent injection is commenced.

Modelling

[0061] Reservoir simulations were performed to demonstrate the process. A live oil simulation model with methane dissolved in bitumen at reservoir conditions was utilized with Northern Alberta oil sands reservoir properties.

[0062] Simulation parameters utilized are included in Table 1 below.

Table 1: Simulation Parameters

Rich Pay thickness	15m
Well Spacing	100m
Well Length	800m
Symmetry	Half
Model grid Block Dimensions	1m wide x 1m thick x 50m long
Porosity	0.33
Reservoir Temperature	15°C
Reservoir Pressure	3000kPa
Initial Oil Saturation	80%
Vertical Permeability	5 darcies
Horizontal Permeability	6 darcies
Methane mole fraction in Oleic Phase	0.13
GOR	10m3/m3
Oil API	8.5

Well Completions

[0063] For the simulations described herein, a typical Northern Alberta Oil Sands SAGD well completion was simulated. 95% quality steam was injected into the reservoir at 3100 kPa while the producer was operated at a gas production rate constraint of 20 t/day.

[0064] A solvent injection well was placed near a top of the reservoir, 50m laterally spaced from the SAGD well pair, assuming 100m spacing between well pairs. After the steam chamber enveloped the solvent injection well, cold liquid propane at 5°C was injected at 20t/day. During propane injection, the steam chamber pressure was maintained at 3100kPa by controlling steam injection rate. The propane injection rate was kept the same as the gas production rate on the basis that the production pump should handle similar amounts of gas volumes as

handled during SAGD and should not be subjected to unnecessary stressful operating conditions as a result of substantially increased gas volumes.

Results

[0065] FIG. 3 illustrates the extent of steam chamber development during SAGD in the first 3 years of the hydrocarbon recovery operation. The steam chamber spread laterally up to 50m away from the SAGD well pair. Because the simulation was performed utilizing a homogeneous model, 48% of original oil was recovered over this time period. Recovery is expected to be lower at the time adjacent steam chambers merge in heterogeneous reservoirs.

[0066] Liquid propane injection at a temperature of 5°C was commenced at 3 years at the rate of 20t/day utilizing the solvent injection well at the top of the reservoir and 50m laterally spaced from the SAGD well pair. FIG. 4 illustrates the spread of propane within the oleic phase at the end of 60 days of injection. Initial injection of liquid propane into the steam chamber occurred about 300m from the heel of the solvent injection well, where the steam chamber made initial overlap with the well.

[0067] Referring to FIG. 4, after 60 days, propane had spread 600m along the length of the well. This significant spread of propane is explained on the basis of prevailing pressure gradients in the steam chamber (illustrated in FIG. 5). The fastest growth of the steam chamber occurred laterally away from the location of the steam sub (which was at 300m from the heel of the steam injection well). A plane of high pressure existed perpendicular to the SAGD injection well at that location. The pressure also decreased in a perpendicular direction from this plane along the length of the well.

[0068] Latent heat is absorbed by the liquid propane as the propane drains into the hot steam chamber and at least some propane is vaporized. It appears that once vaporized, propane is pushed out into the steam chamber along the pressure gradients. Because propane is injected and is mobile at the outer edges of the steam chamber, the prevailing pressure gradients seem to contain and quickly allow the solvent to spread along the steam chamber boundaries. Propane lowers

the temperature at the edges of the steam chamber by absorbing the latent heat, which also increases solvent solubility in the oleic phase. Dissolved propane mobilizes the oil by reducing its effective viscosity.

[0069] FIG. 6 shows the impact of cold liquid propane addition at 3 years on the oil production rate. Oil rate (rate of production of oil) modelled for SAGD is also plotted for comparison. The oil rate for the cold solvent process started to increase roughly 60 days after the start of propane injection. Oil rate increased almost to the level of the first peak production rate achieved during the ramp-up stage of SAGD (that is, in the early part of year 1 after the initial spike in oil rate shown), before starting to decline. The decline happened over an extended period of time (from about 3.5 to about 5 years) over which the oil rate stayed significantly higher than the observed rate for SAGD.

[0070] FIG. 7 depicts steam (BBL/day), propane (tonnes/day) and methane (tonnes/day) injection rates over time for SAGD compared to cold solvent processes as described herein. Although oil rate started increasing roughly 60 days after propane injection was started at 3 years, the impact on steam injection was observed very quickly. Steam injection rate (shown in BBL/day) dropped by 50% immediately (dashed line) as the vaporized propane and trace amounts of methane helped maintain the steam chamber pressure. A slight increase in steam rate was observed for a short period of time during the ramp up in oil rate after propane was injected; however, eventually the rate decreased steadily as the proportion of methane injected (solid light line) with propane was increased. After a desired recovery was achieved, which, in this example, was 75% of oil in place, steam and propane injection were both ceased (at about 5 years). Steam and propane injection were replaced by 100% methane injection and the wells were switched over to the blowdown stage. Steam injection rate (BBL/day) for SAGD absent solvent injection is shown (solid dark line) in FIG. 7 for comparison.

[0071] The immediate impact of propane injection on reducing steam injection rate may be advantageous. Cold propane may be injected into mature wells while steam is diverted to newer wells.

[0072] FIG. 8 shows the cumulative (%) oil recovery comparison between a cold solvent process and SAGD. Propane injection starting at 3 years significantly accelerated oil recovery. Propane injection was started when 48% oil in place was recovered. Over the next 2.1 years, the recovery ramped up to 75% of oil in place recovered. As illustrated in FIG. 8, SAGD required an additional 3 years (8 years total compared to 5 years for the cold solvent process) to reach the same recovery level.

[0073] FIG. 9 shows the energy equivalent cumulative steam to oil ratio (eCSOR) for the cold solvent process compared to SAGD. The eCSOR for the cold solvent process was calculated as the ratio of energy injected to energy produced from the reservoir against the volumetric ratio of water injected to oil produced utilized in a standard SAGD SOR calculation. The present process required 37% less energy compared to SAGD for recovery of 75% oil in place. Advantageously, significantly less energy was utilized (as shown in FIG. 9) and oil recovery was accelerated (as illustrated in FIG. 8).

[0074] FIG. 10 is a graph illustrating propane injected into the solvent injection well and propane produced through the production well. Propane injection was started at 3 years and propane production from the production well began after 2 months of injecting propane. Initially trace amounts of methane were injected with propane and over time the proportion of methane to propane was steadily increased. Production rates of propane also increased over time. After 1.3 years of propane injection, propane for injection was not required as the rate at which propane was produced was comparable to the rate at which the propane was injected. Thus, the propane produced was re-injected. Propane injection was stopped at 5.1 years (2.1 years after start of injection), after recovery of 75% oil in place. After discontinuing propane injection, the wells were switched to blowdown with injection of methane. Propane production from the reservoir continued over the next 1 year along with bitumen. Cumulatively, 93% of injected propane was recovered at the end of 6.5 years.

[0075] As indicated above, steam injection may be discontinued completely upon commencement of injecting the liquid solvent and non-condensable gas. The

liquid solvent and non-condensable gas in this example are injected at a rate sufficient to maintain the pressure in the steam chamber by the methane and vaporized solvent.

[0076] For the purpose of comparison, the following three scenarios were modelled: (i) SAGD alone, (ii) SAGD followed by fixed rate propane injection beginning at 3 years with continuation of steam injection, and (iii) SAGD followed by propane injection beginning at 3 years with discontinuation of steam injection (i.e., steam injection was discontinued when propane injection commenced). Resulting oil production rates are illustrated in the graph of FIG. 11. The injection of propane with discontinuation of steam, i.e., at higher rates compared to injection with continued steam, resulted in a rapid increase in the oil production rate. The oil production rate for the injection of propane with discontinued steam was sustained (in the early part of year 3) at levels higher than those observed during the ramp-up stage of SAGD (that is, in the early part of year 1 after the initial spike in oil rate shown).

[0077] As shown in FIG. 12, the injection of cold liquid propane with discontinued steam injection resulted in an eCSOR value for 75% oil recovery that was 52% lower than that for SAGD; this benefit was realized as steam injection was ceased at 3 years. The eCSOR value for 75% oil recovery resulting from SAGD followed by fixed rate propane injection and continuation of steam injection was in between the values of the other two scenarios.

[0078] FIG. 13 shows that 75% of oil in place was recovered in only 4.35 years when propane was injected at 3 years with discontinued steam injection, which was roughly half of the time taken by SAGD to recover the same volume of oil. The process of injecting fixed rate propane at 3 years with continued steam injection also led to faster recovery of 75% of oil in place than SAGD alone, but more slowly than when propane was injected with discontinued steam injection.

[0079] The results of injection of relatively cold solvent with continuation of steam injection and the injection of relatively cold solvent with discontinuation of steam injection illustrate two examples of cold solvent processes leading to oil production enhancement compared to SAGD. The production enhancement realized

in other variations of these two processes may lie between the two production curves shown in FIG. 11.

[0080] Simulation results show that the injection of relatively cold solvent according to the present disclosure reduced the energy required for recovering bitumen and accelerated production. In the results shown, the production pump was operated at the same gas handling capacity as in SAGD, meaning that higher production rates may be achieved without undue strain on the pump. Advantageously, decoupling solvent and steam injection, i.e., injecting the solvent via a solvent injection well separate from the injection of steam, provides a relatively simpler design for commercial implementation. Again, a benefit of the process is that the solvent need not be heated.

[0081] The described embodiments are to be considered in all respects only as illustrative and not restrictive. The scope of the claims should not be limited by the preferred embodiments set forth in the examples, but should be given the broadest interpretation consistent with the description as a whole. All changes that come with meaning and range of equivalency of the claims are to be embraced within their scope.

Claims

1. A process for recovering hydrocarbons from a hydrocarbon-bearing formation, the process comprising:

injecting steam into injection wells disposed in a lower portion of the hydrocarbon-bearing formation and laterally spaced apart to create respective steam chambers extending upwardly in the hydrocarbon-bearing formation;

producing the hydrocarbons from the hydrocarbon-bearing formation;

injecting a solvent through a further well disposed in an upper portion of the hydrocarbon formation, such that the solvent, which is cold relative to a steam chamber temperature, is delivered to a location generally between the laterally spaced injection wells in the hydrocarbon-bearing formation and spaced vertically upwardly therefrom.

2. The process according to claim 1, wherein the solvent is injected at ambient temperature at the wellhead.

3. The process according to claim 1 or claim 2, wherein the solvent is injected at sub-fracturing pressure and flow rate.

4. The process according to any one of claims 1 to 3, wherein the injecting steam and producing the hydrocarbons are carried out in a steam-assisted gravity drainage (SAGD) process or a SAP.

5. The process according to any one of claims 1 to 4, wherein the solvent comprises a solvent having 2 to 8 carbon atoms per molecule.

6. The process according to any one of claims 1 to 5, wherein the solvent comprises propane.

7. The process according to any one of claims 1 to 6, comprising injecting a non-condensable gas along with the solvent.

8. The process according to claim 7, wherein the non-condensable gas comprises methane or carbon dioxide.

9. The process according to claim 7 or claim 8, comprising increasing a proportion of the non-condensable gas to the solvent injected over time.

10. The process according to claim 9, comprising decreasing a volume of steam injected with an increase in volume of non-condensable gas.

11. The process according to any one of claims 1 to 10, wherein injecting the solvent through the further well is carried out after coalescence of adjacent ones of the steam chambers.

12. The process according to any one of claims 1 to 10, comprising determining that adjacent ones of the steam chambers have coalesced prior to injecting solvent, wherein injecting the solvent is carried out in response to coalescence of the adjacent ones of the steam chambers.

13. The process according to any one of claims 1 to 12, wherein injecting solvent comprises continually injecting solvent until a blowdown stage.

14. The process according to any one of claims 1 to 13, wherein the further well is configured to deliver solvent to at least two locations between laterally spaced injection wells and spaced vertically upwardly therefrom, including the location between a first injection well and a second injection well, and a second location, between the second injection well and a third injection well.

15. The process according to any one of claims 1 to 13, wherein the further well includes a horizontal section that extends in a direction generally transverse to that of the injection wells.

16. The process according to claim 15, comprising utilizing flow control devices in the further well to control the flow of solvent to a plurality of locations generally between laterally spaced injection wells, including the location between a first injection well and a second injection well, and a second location, between the second injection well and a third injection well.

17. A process for removing hydrocarbons from a hydrocarbon-bearing formation having injection and production well pairs extending into a lower portion of the hydrocarbon-bearing formation, the injection and production well pairs being laterally spaced apart within the hydrocarbon-bearing formation, each injection and production well pair including an injection well vertically spaced above a production well, the process comprising:

injecting steam into the injection wells and removing hydrocarbons utilizing the production wells, thereby forming respective steam chambers extending into the hydrocarbon bearing formation from the injection wells;

after coalescence of steam chambers of adjacent injection and production well pairs, injecting a liquid solvent through a solvent injection well disposed in an upper portion of the hydrocarbon formation, to deliver liquid solvent to a location generally between the adjacent injection and production well pairs in the hydrocarbon-bearing formation.

18. The process according to claim 17, wherein the liquid solvent is injected at ambient temperature at the wellhead.

19. The process according to claim 17 or claim 18, wherein the solvent is injected at sub-fracturing pressure and flow rate.

20. The process according to any one of claims 17 to 19, wherein the injecting steam and producing the hydrocarbons is carried out in a steam-assisted gravity drainage (SAGD) process or a SAP.

21. The process according to any one of claims 17 to 20, wherein the solvent comprises a solvent having 2 to 8 carbon atoms per molecule.

22. The process according to any one of claims 17 to 21, wherein the solvent comprises propane.

23. The process according to any one of claims 17 to 22, comprising injecting a non-condensable gas along with the solvent.

24. The process according to claim 23, wherein the non-condensable gas comprises methane or carbon dioxide.

25. The process according to claim 23 or claim 24, comprising increasing a proportion of the non-condensable gas to the solvent injected over time.

26. The process according to claim 25, comprising decreasing a volume of steam injected with an increase in volume of non-condensable gas.

27. The process according to any one of claims 17 to 26, comprising determining that adjacent ones of the steam chambers have coalesced prior to injecting solvent, wherein injecting the solvent is carried out in response to coalescence of the adjacent ones of the steam chambers.

28. The process according to any one of claims 17 to 27, wherein injecting solvent comprises continually injecting solvent until a blowdown stage.

29. The process according to any one of claims 17 to 28, wherein the solvent injection well is configured to deliver solvent to at least two locations between laterally spaced injection and production well pairs and spaced vertically upwardly therefrom, including the location between a first injection and production well pair and a second injection and production well pair, and a second location between a second injection and production well pair and a third injection and production well pair.

30. The process according to any one of claims 17 to 28, wherein the solvent injection well includes a horizontal section that extends in a direction generally transverse to that of the injection wells.

31. The process according to claim 30, comprising utilizing flow control devices in the solvent injection well to control the flow of solvent to a plurality of locations generally between laterally spaced injection and production well pairs and spaced vertically upwardly therefrom, including the location between a first injection and production well pair and a second injection and production well pair, and a second location between a second injection and production well pair and a third injection and production well pair.

FIG. 1A

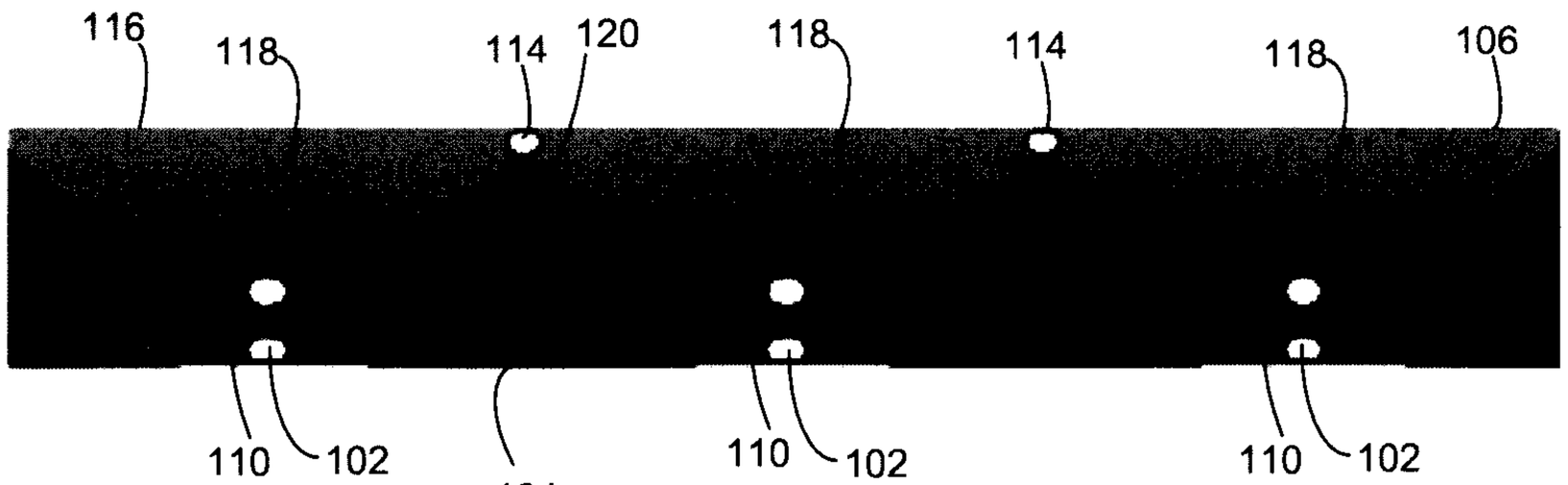
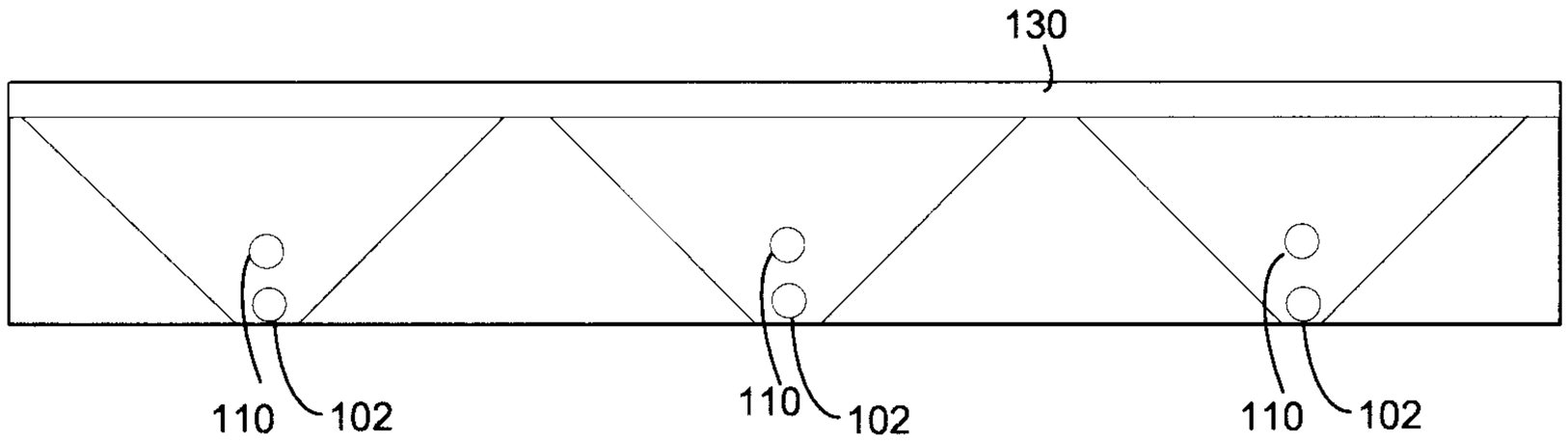


FIG. 1B



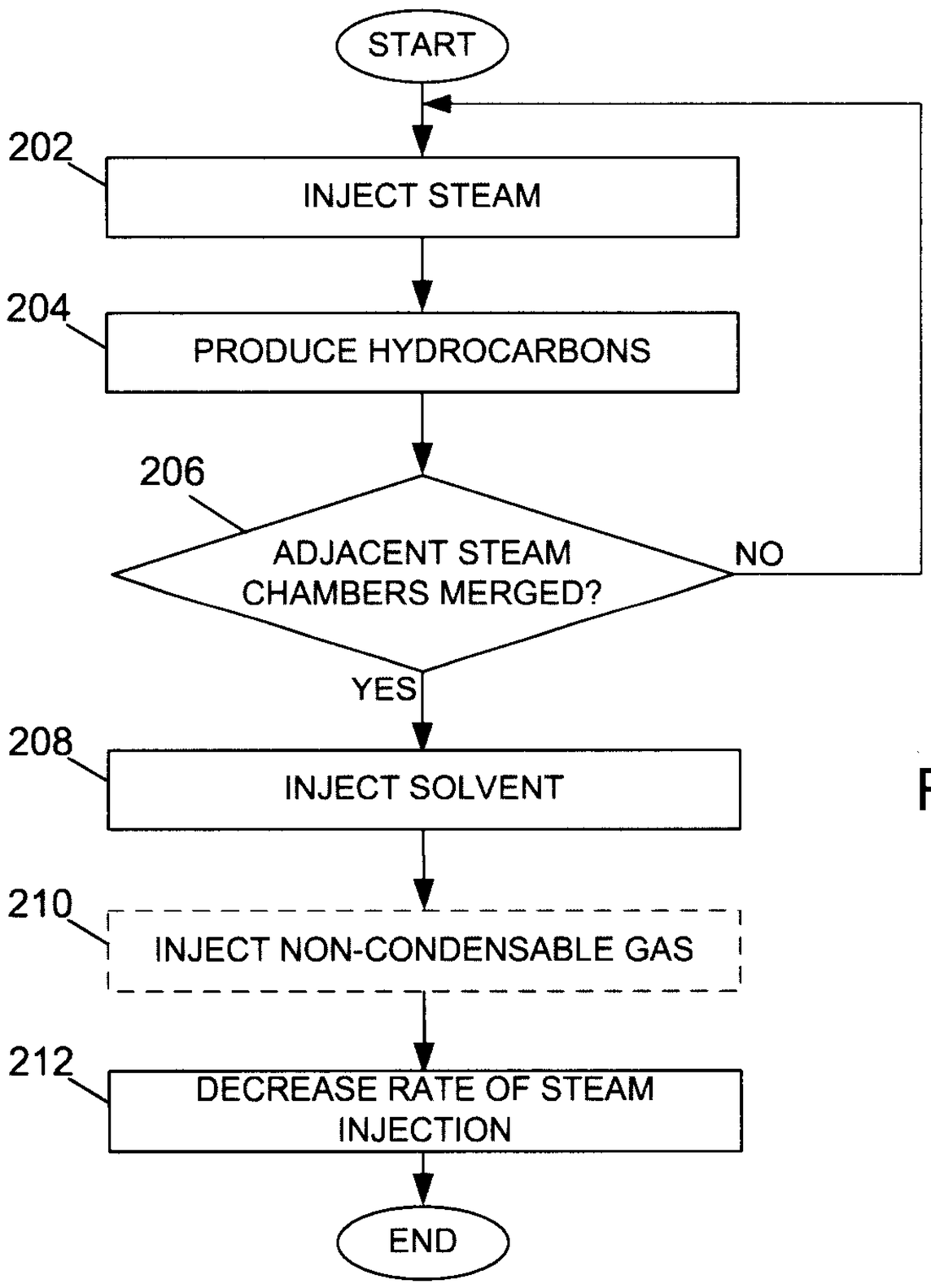


FIG. 2

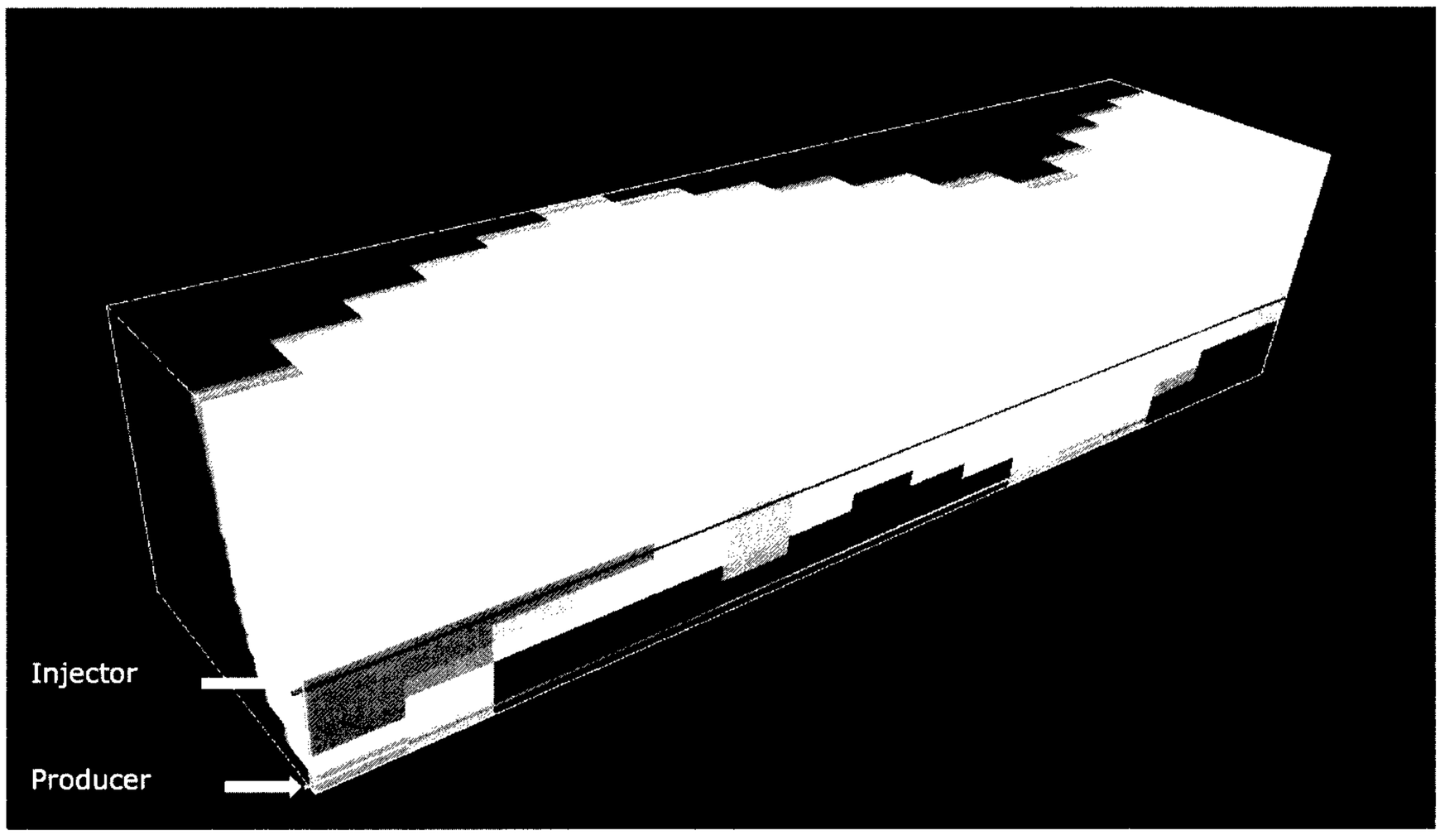


FIG. 3

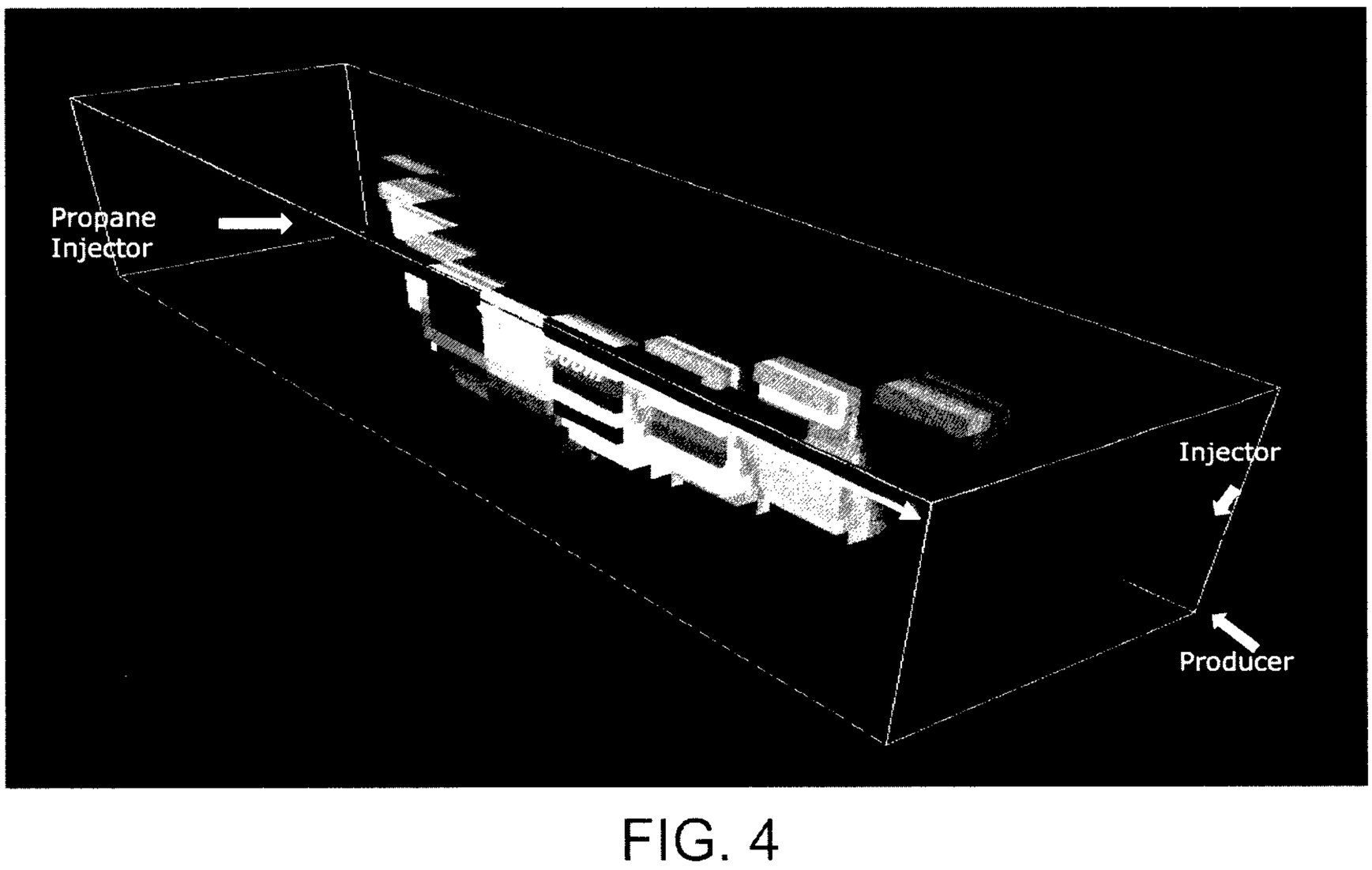


FIG. 4

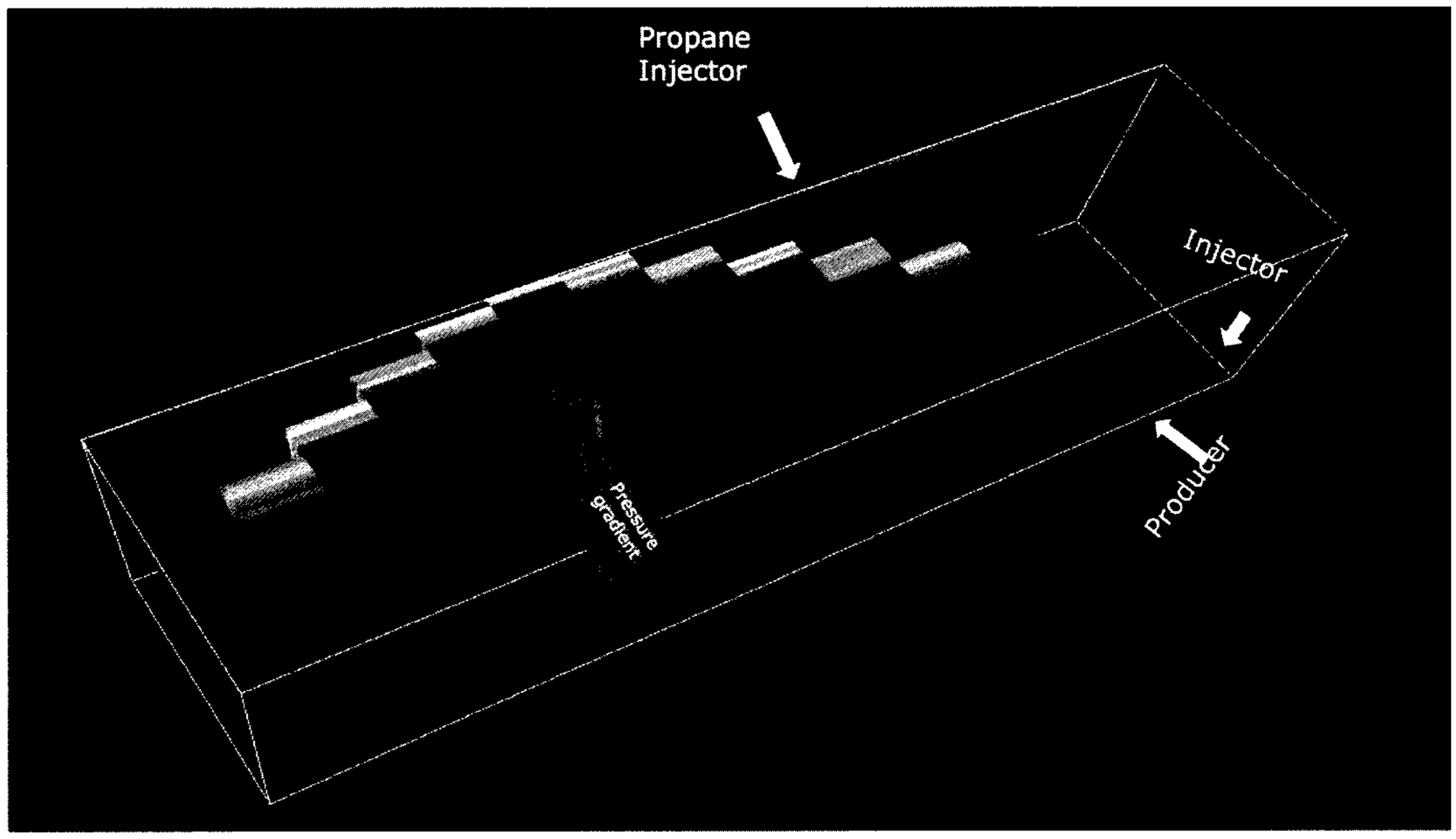

Propane
Injector
Injector
Pressure
gradient
Producer

FIG. 5

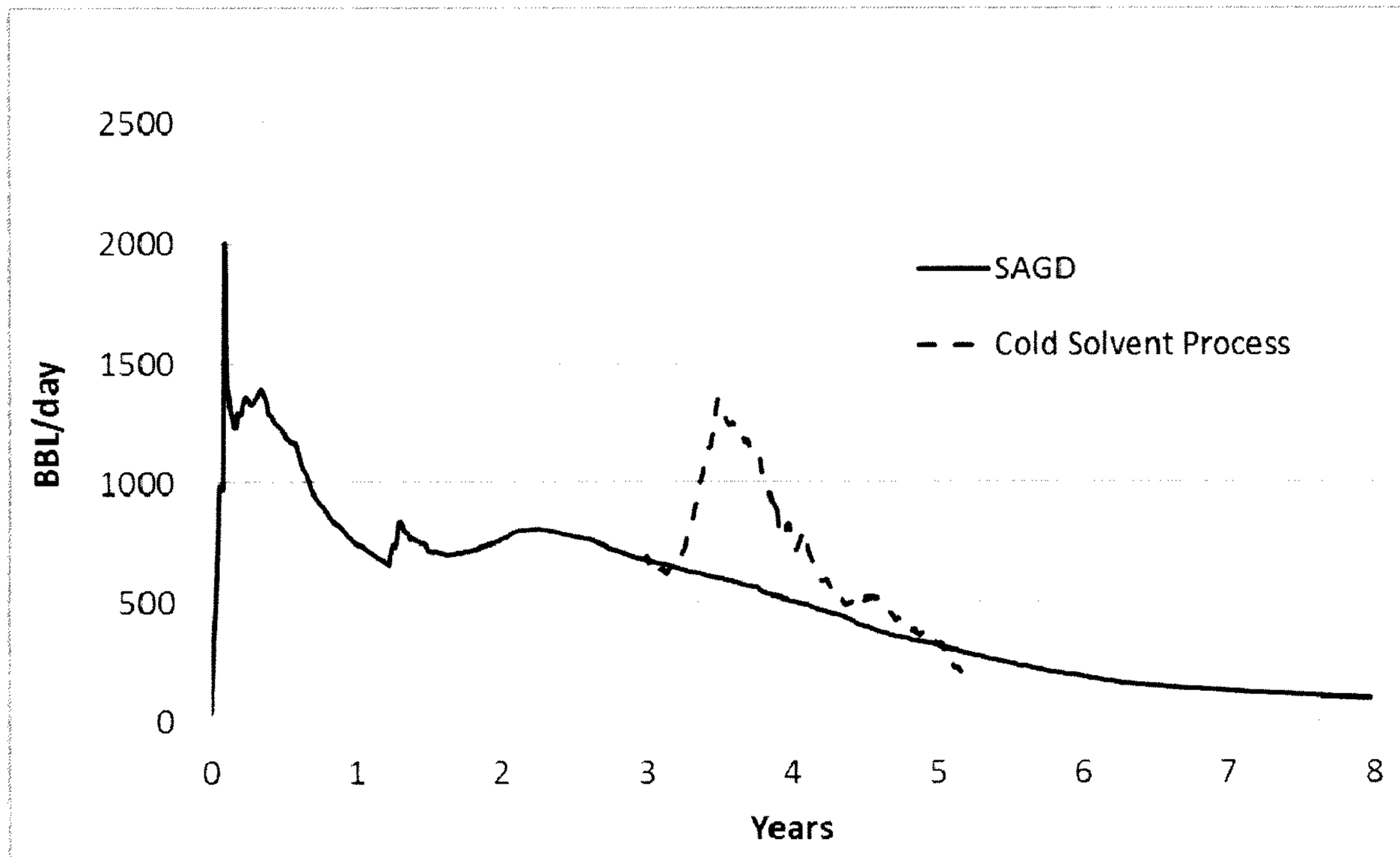

2500
2000
1500
1000
500
0
BBL/day
SAGD
Cold Solvent Process
0
1
2
3
4
5
6
7
8
Years

FIG. 6

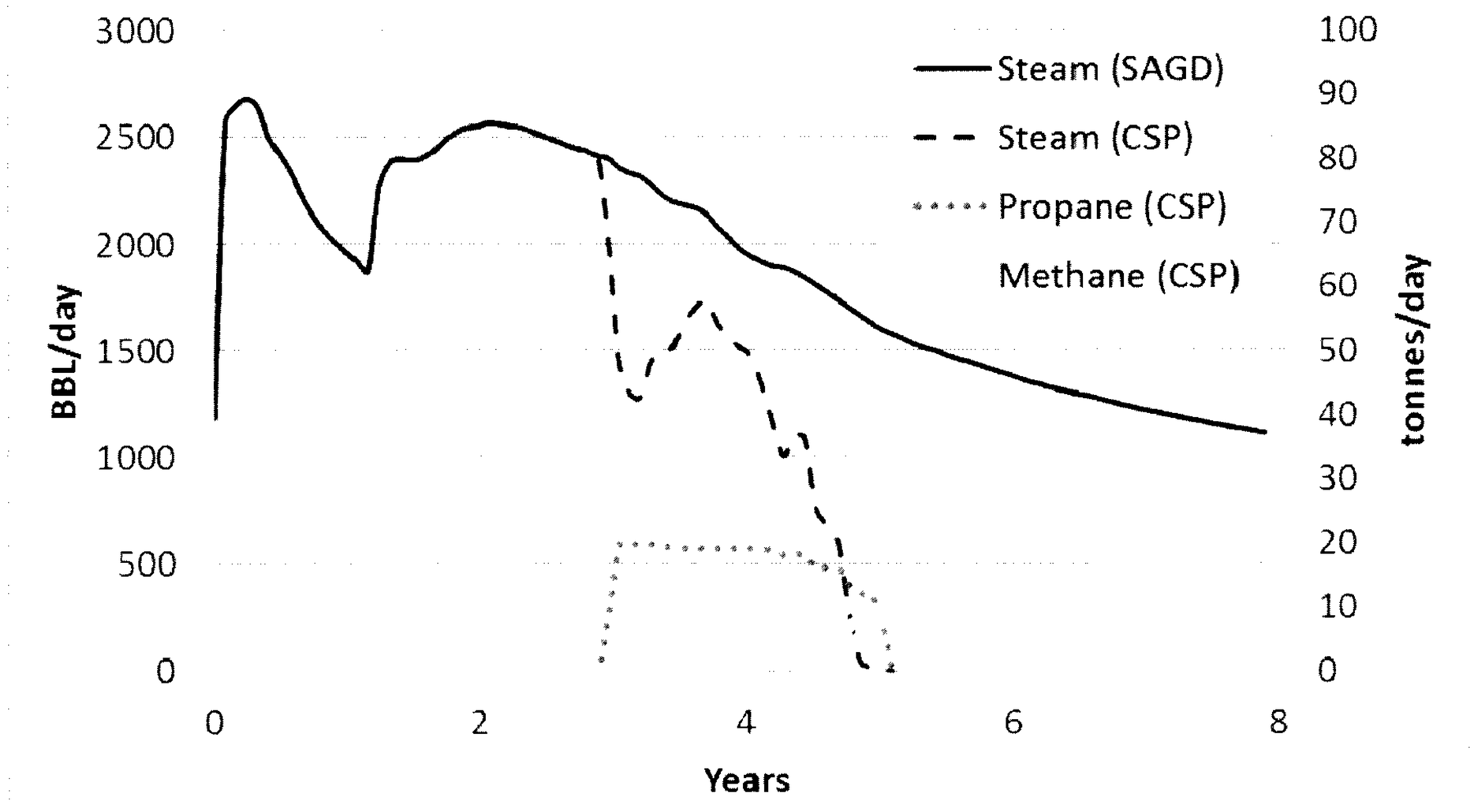

3000
2500
2000
1500
1000
500
0
BBL/day
100
90
80
70
60
50
40
30
20
10
0
tonnes/day
0
2
4
6
8
Years
Steam (SAGD)
Steam (CSP)
Propane (CSP)
Methane (CSP)

FIG. 7

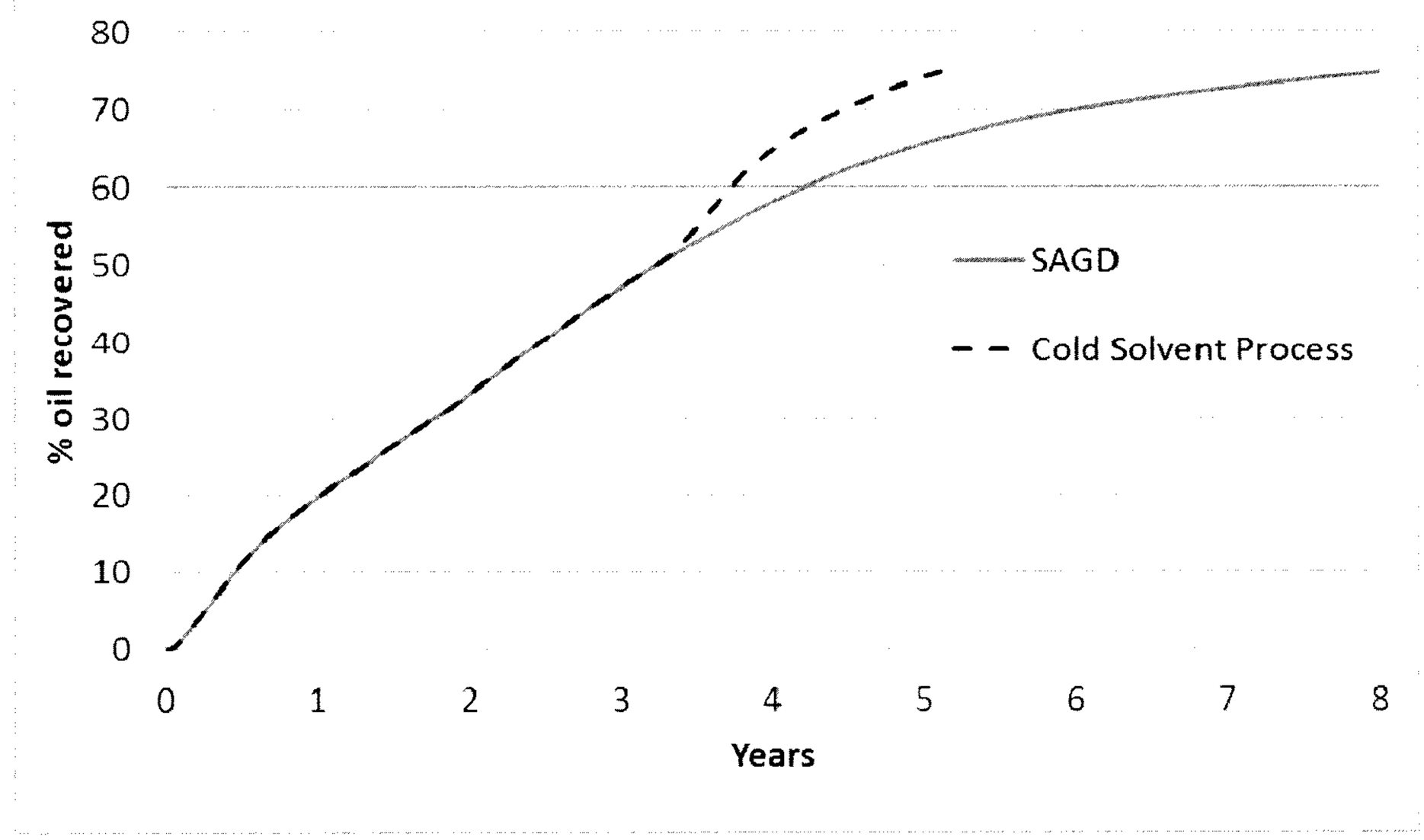

80
70
60
50
40
30
20
10
0
% oil recovered
0
1
2
3
4
5
6
7
8
Years
SAGD
Cold Solvent Process

FIG. 8

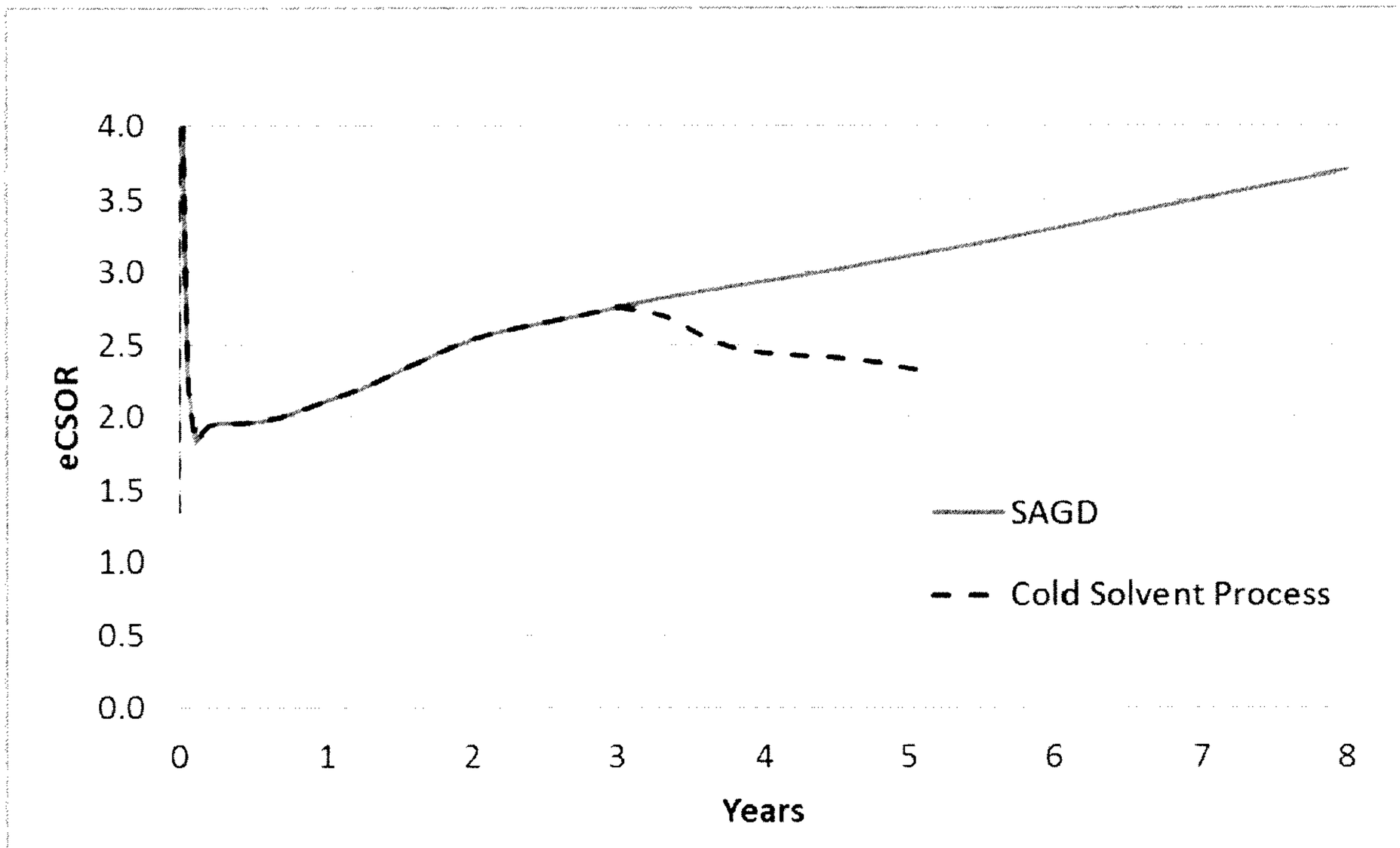

4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
eCSOR
0
1
2
3
4
5
6
7
8
Years
SAGD
Cold Solvent Process

FIG. 9

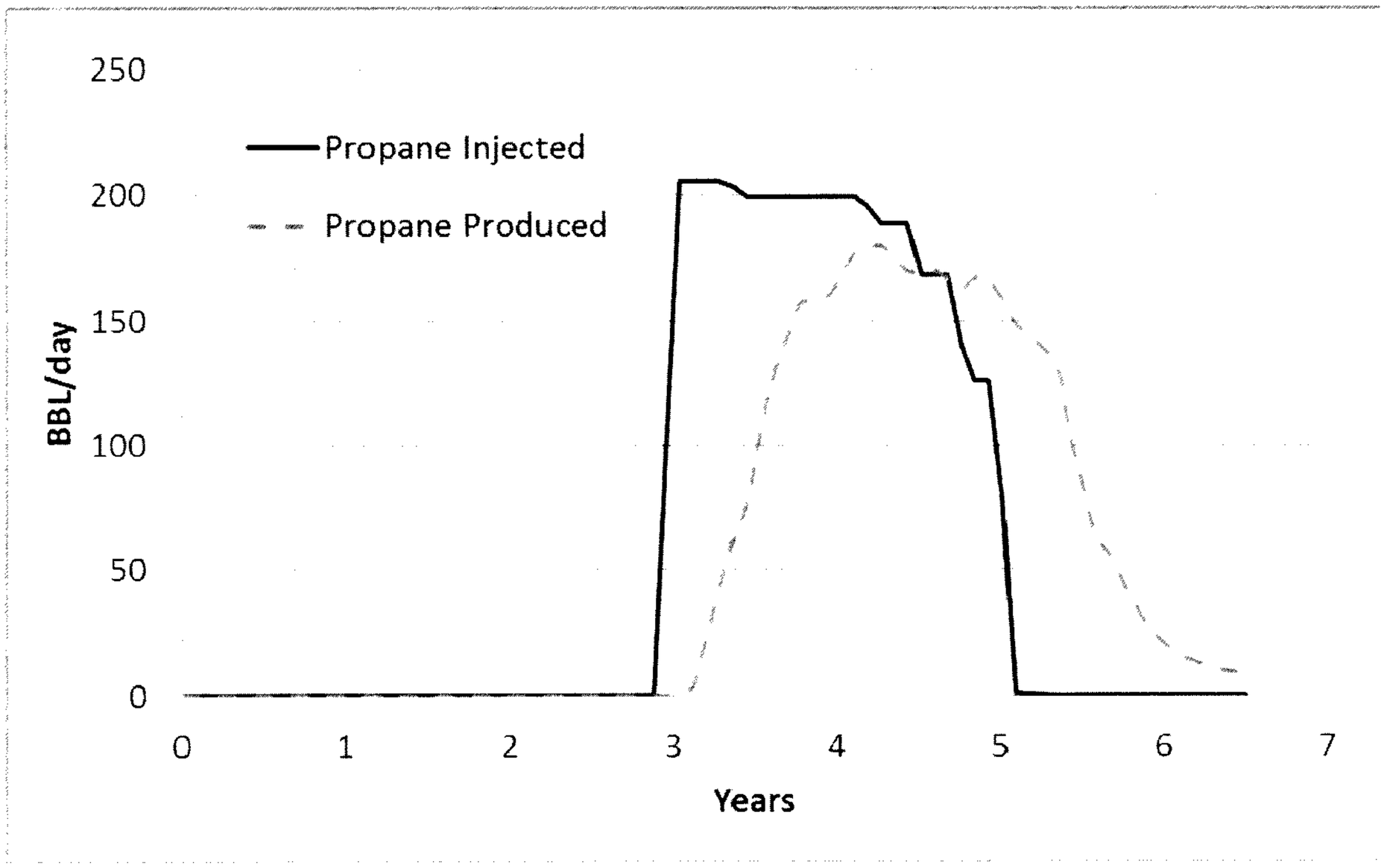

250
200
150
100
50
0
BBL/day
0
1
2
3
4
5
6
7
Years
Propane Injected
Propane Produced

FIG. 10

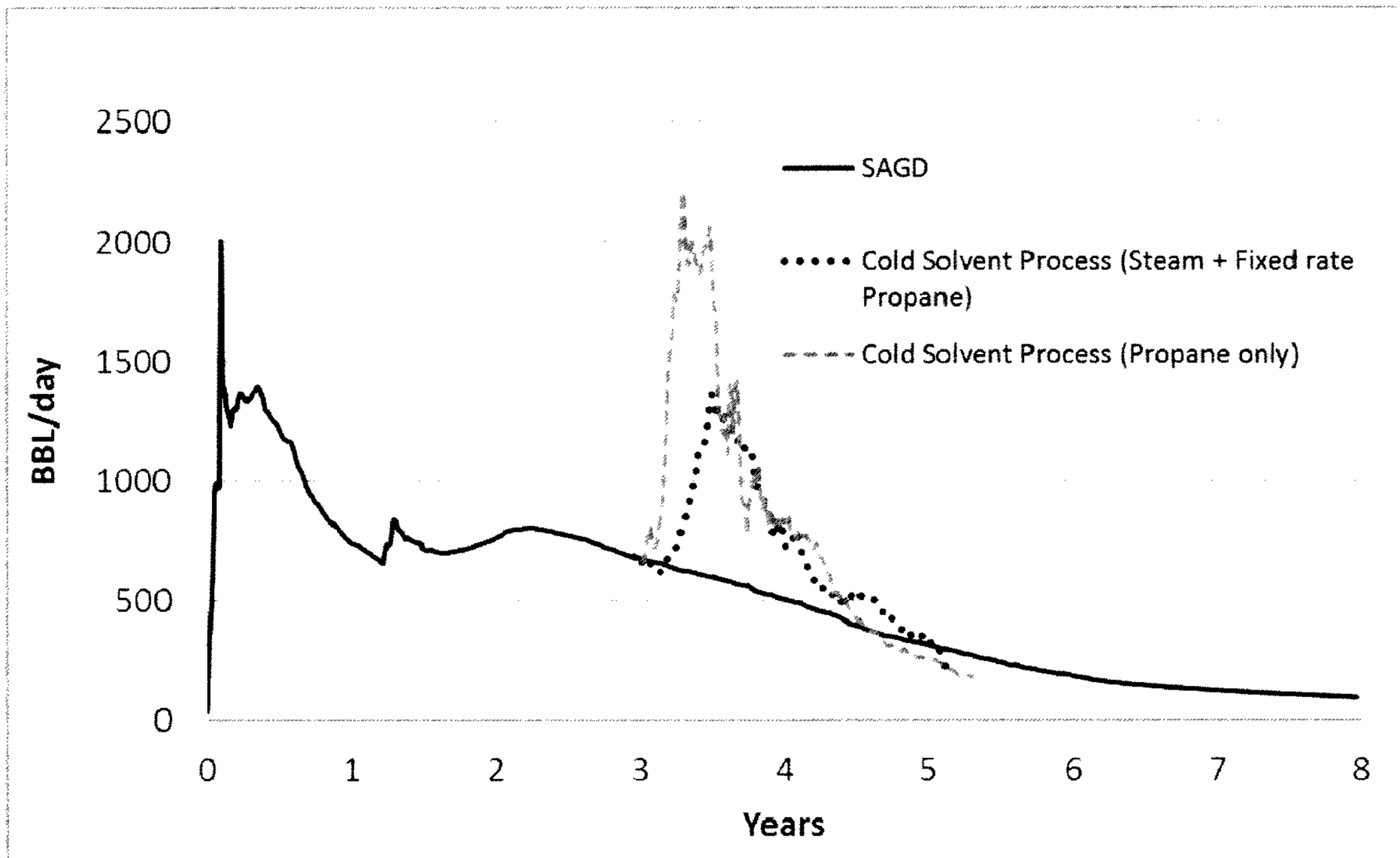

2500
2000
1500
1000
500
0
BBL/day
0
1
2
3
4
5
6
7
8
Years
SAGD
Cold Solvent Process (Steam + Fixed rate Propane)
Cold Solvent Process (Propane only)

FIG. 11

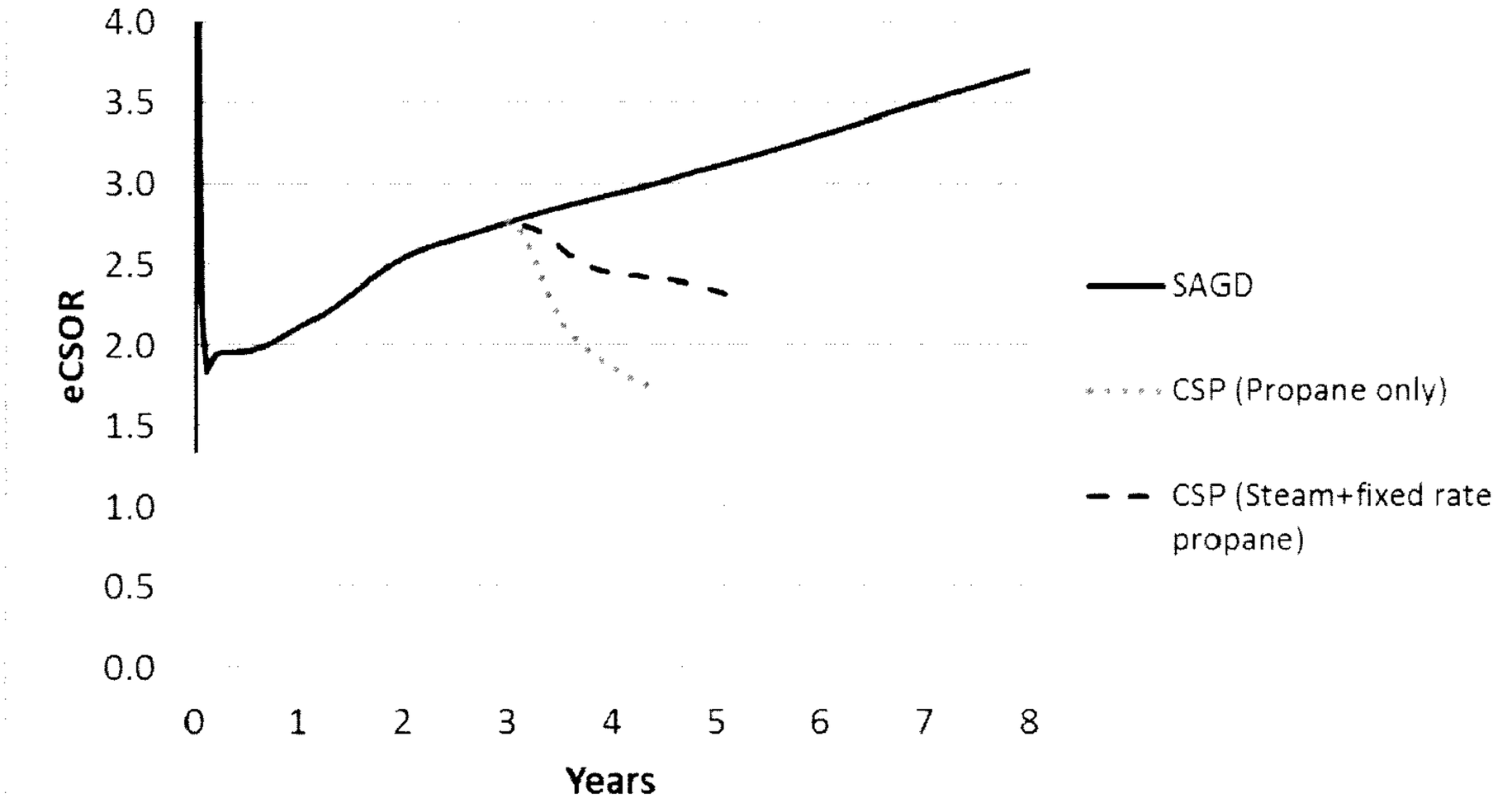

4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
eCSOR
0
1
2
3
4
5
6
7
8
Years
SAGD
CSP (Propane only)
CSP (Steam+fixed rate propane)

FIG. 12

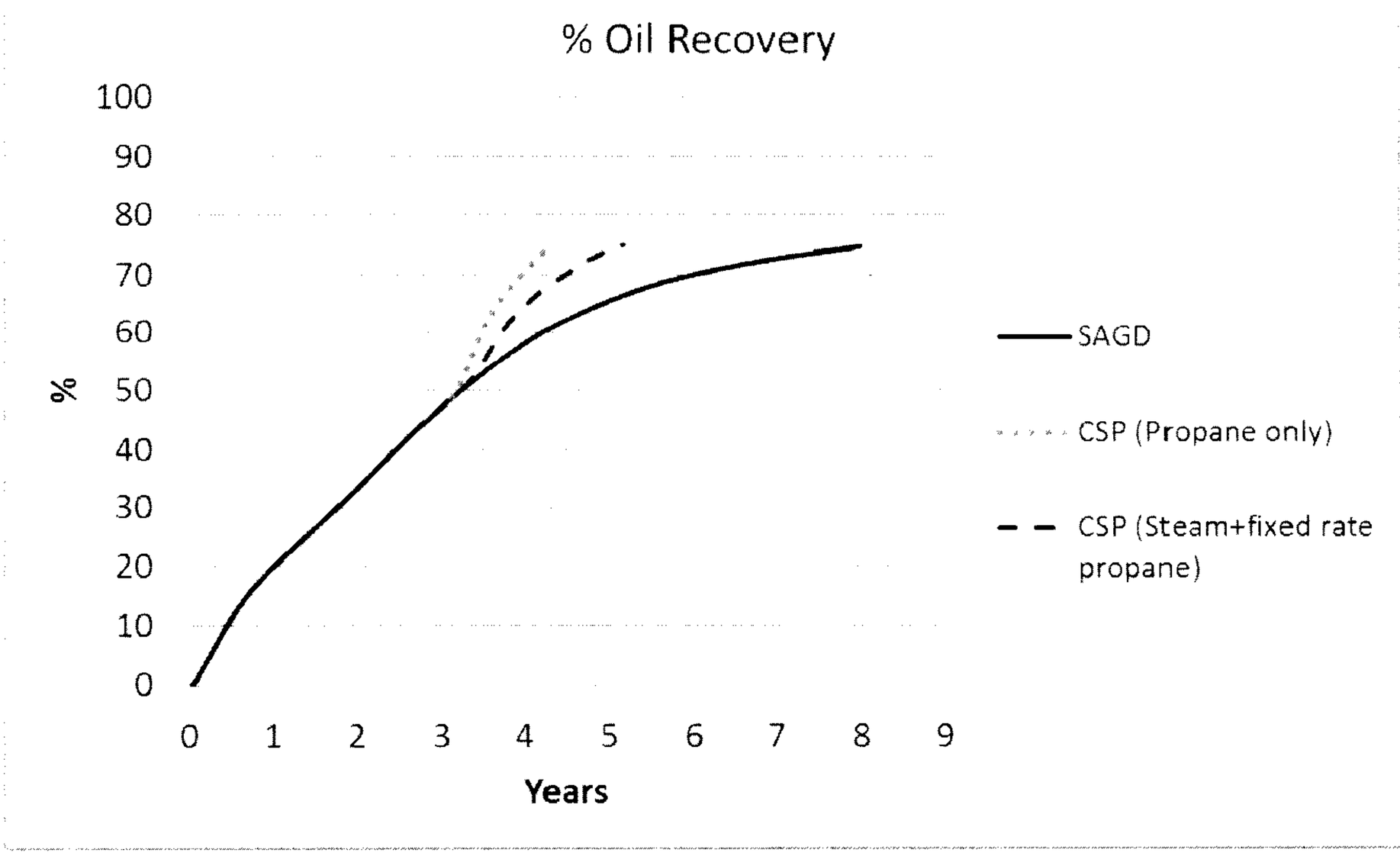
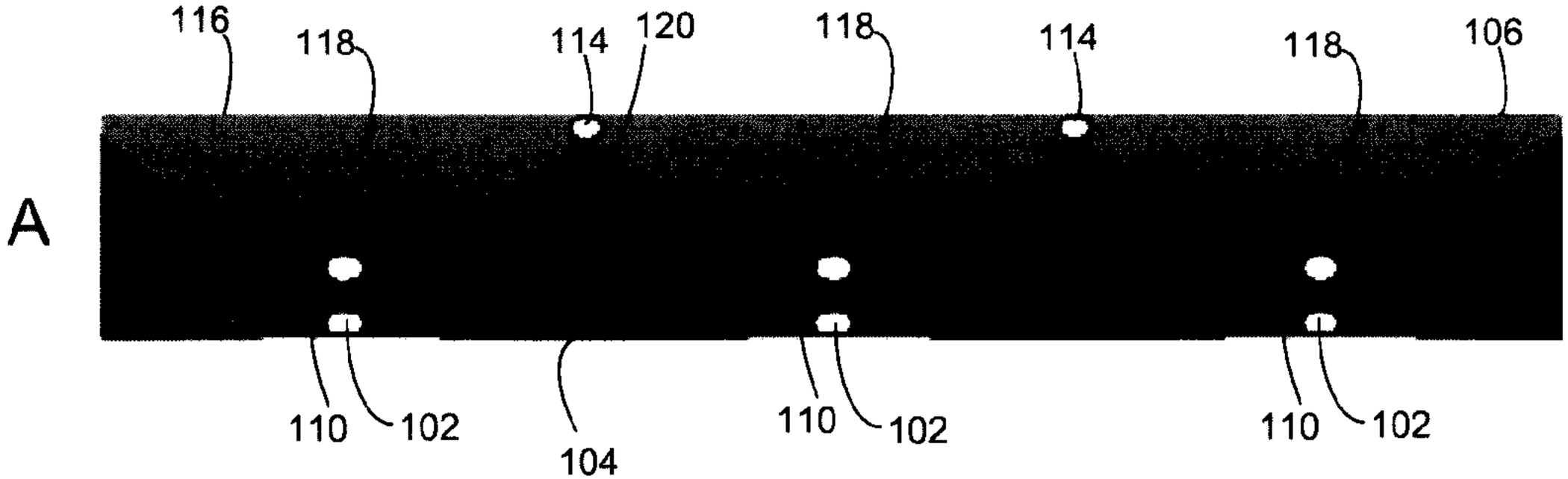

% Oil Recovery
100
90
80
70
60
50
40
30
20
10
0
%
0
1
2
3
4
5
6
7
8
9
Years
SAGD
CSP (Propane only)
CSP (Steam+fixed rate propane)

FIG. 13


A
116
118
114
120
118
114
118
106
110
102
104
110
102
110
102