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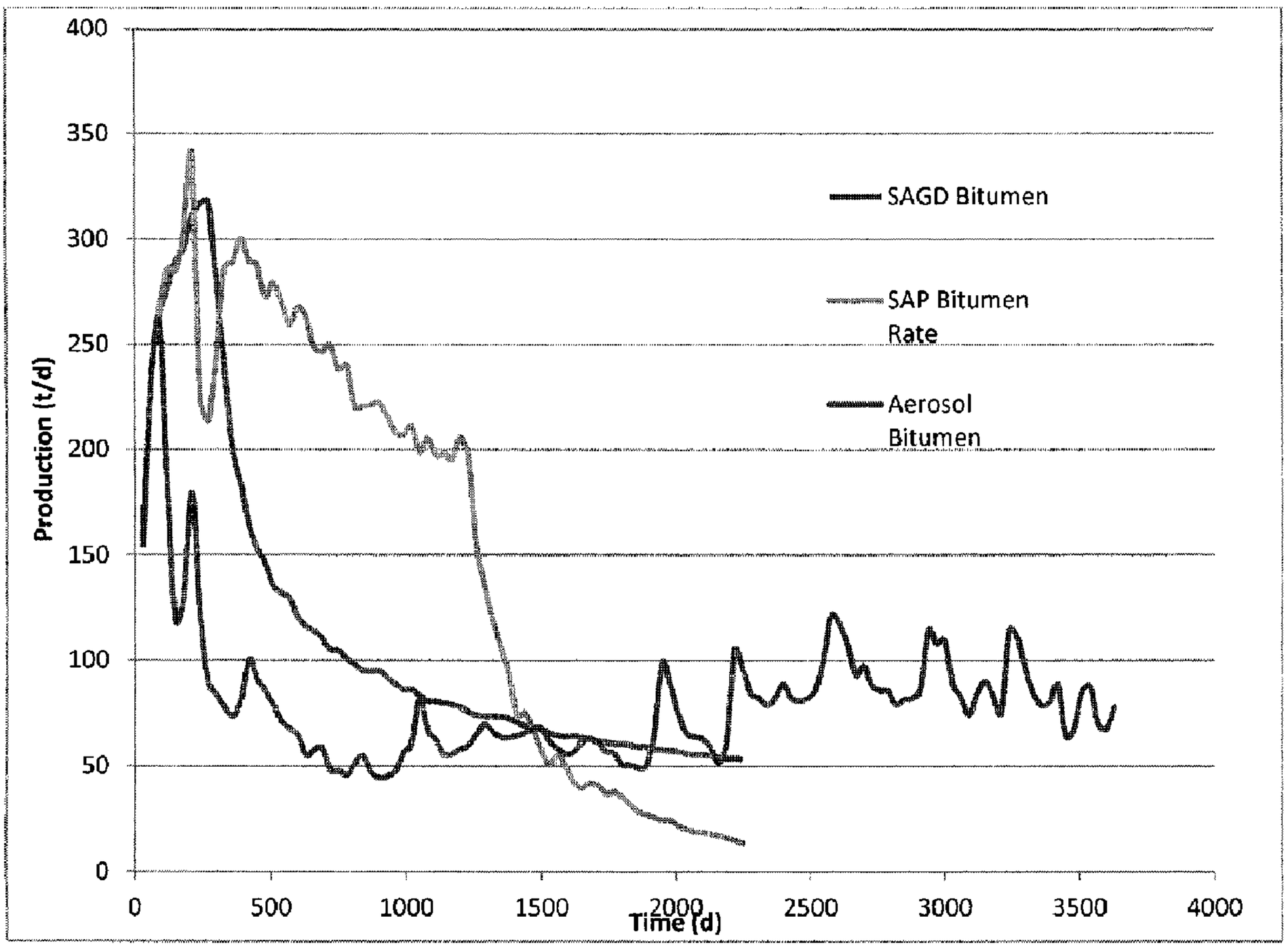
(54) **Titre : EXTRACTION DE PETROLE LOURD AU MOYEN DE LIQUIDES ENTRAINES PAR LE GAZ**
(54) **Title: HEAVY OIL EXTRACTION USING LIQUIDS SWEPT ALONG BY GAS**



(57) **Abrégé/Abstract:**
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(57) **Abrégé(suite)/Abstract(continued):**
NCGs effectively sweep the entrained DSLs through the formation, in a process that is characterized as providing liquids swept along by gas (LSAG).

ABSTRACT

Oil recovery processes are provided that utilize aspects of non-condensing gas (NCG) flow management to deliver an entrained diluent/solvent liquid (DSL) to an oil interface within a reservoir, with the entrained DSL then mobilizing the oil for production. The NCGs effectively sweep the entrained DSLs through the formation, in a process that is characterized as providing liquids swept along by gas (LSAG).

HEAVY OIL EXTRACTION USING LIQUIDS SWEPT ALONG BY GAS

FIELD OF THE INVENTION

[0001] The invention is in the field of hydrocarbon reservoir engineering, particularly solvent-assisted recovery processes in heavy oil reservoirs.

BACKGROUND OF THE INVENTION

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

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

well remains located at the bottom of the steam chamber in an appropriate position to collect mobilized hydrocarbons.

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

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

[0006] A wide variety of alternative enhanced or in-situ recovery processes may be used that employ thermal and non-thermal components to mobilise oil. A wide variety of processes have been described that use hydrocarbon solvents in addition to steam, or in place of steam, in processes analogous to conventional SAGD, or in processes that are alternatives to SAGD. For example, Canadian Patent Number 2,299,790 describes methods for stimulating heavy oil production using a propane vapor. Similarly, Canadian Patent No. 2,323,029 describes an *in situ* recovery process involving injection of steam and a non-aqueous solvent. Unheated hydrocarbon vapours have been proposed for use to dissolve and displace heavy oils in a process known as VAPEX (Butler and Mokrys, J. Can. Petro. Tech. 1991,30; U.S. Pat. No. 5,407,009). Processes for cyclic steam stimulation of vertical wells using hydrocarbon solvents have been described (Leaute and Carey, J. Can. Petro. Tech., Vol. 46, No. 9, pp. 22-30, 2007). Field trials have also been reported for solvent assisted processes that involve the use of solvent, such as butane, as an addition or aid to injected steam in improving the performance of conventional SAGD (Gupta et al., Paper 2001-126, Can. Intl. Pet. Conf., Calgary, Alberta, June 12-14, 2001; Gupta et al., Paper No. 2002-299, Can. Intl. Pet. Conf., Calgary, Alberta, June 11-13, 2002;Gupta and Gittins, Paper No. 2005-190, Can. Intl. Pet. Conf., Calgary, Alberta, June 7-9, 2005). Similarly, solvent assisted processes characterized as Liquid Assisted Steam Enhanced Recovery (LASER) have been described, in which solvents are used in conjunction with steam to enhance performance of Cyclic Steam Stimulation (CSS).

[0007] The complexities associated with heavy oil recovery processes involving solvents are considerable. As for example, illustrated by Canadian Patent Application 2,660,227, which describes numerical simulations of alternative hybrid solvent processes. Numerical studies have suggested that simple addition of propane to steam may be ineffective, with the propane failing to condense and thereby acting as a noncondensable gas (Zhao, SPE 86957 presented at the SPE International Thermal Operations and Heavy Oil Symposium , Bakersfield, California, 2004). Further complications may be introduced in methods that involve varying solvent compositions over time (Gupta and Gittins J. Can. Petro. Tech. September 2007, Vol. 46, No 9; and, Canadian Patent No. 2,462,359).

[0008] Non-condensing gases (NCGs) may be present in heavy oil recovery process for a variety of reasons. In the context of alternative processes, NCGs have been described as offering both benefits and challenges to the optimal performance of a recovery processes, such as SAGD systems. For example, US Patent No. 8,596,357 describes methods for adding a buoyancy-modifying agent to injected steam, such as an additional NCG, to help cause NCGs to accumulate at the top of the steam chamber. This approach reflects the fact that NCGs tend to be light and therefore buoyant, so that any NCG that is liberated or generated lower in the steam chamber will tend to rise to a higher part of the steam chamber, and any NCG produced or released higher in the steam chamber will tend to remain in the upper elevations of the steam chamber. Other aspects of fluid dynamics in the SAGD process influence this vertical NCG flow.

[0009] The management of NCGs in heavy oil recovery process is complicated by the fact that gravity-dominated in situ recovery processes, such as SAGD, rely on vertical flow and displacement. However, given the long horizontal wells that are normally associated with this type of process, and the (axial) flows along the length of the wells, the resulting (radial or transverse) flows from reservoir to well, and vice versa, will tend to be non-uniform, even in a homogeneous reservoir.

[0010] In the context of the present application, various terms are used in accordance with what is understood to be the ordinary meaning of those terms. For example, “petroleum” is a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase, which includes various oxygen-, nitrogen- and sulfur- containing compounds and typically trace amounts of metal-containing compounds. In the context of the present application, the words “petroleum” “oil” and “hydrocarbon” are generally used interchangeably to refer to mixtures of widely varying composition, as will be evident from the context in which the word is used. The production of petroleum from a reservoir necessarily involves the production of hydrocarbons, but is not limited to hydrocarbon production. Similarly, processes that produce hydrocarbons from a well will generally also produce petroleum fluids that are not hydrocarbons. In accordance with this usage, a process for producing petroleum or

hydrocarbons is not necessarily a process that produces exclusively petroleum or hydrocarbons, respectively.

[0011] "Fluids", such as petroleum fluids, include both liquids and gases. Natural gas is the portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural Gas may include amounts of non-hydrocarbons. The abbreviation POIP stands for "producible oil in place" and in the context of the methods disclosed herein is generally defined as the exploitable or producible oil structurally located above the production well elevation.

[0012] It is common practice to segregate petroleum substances of high viscosity and density into two categories, "heavy oil" and "bitumen". For example, some sources define "heavy oil" as a petroleum that has a mass density of greater than about 900 kg/m3. Bitumen is sometimes described as that portion of petroleum that exists in the semi-solid or solid phase in natural deposits, with a mass density greater than about 1000 kg/m3 and a viscosity greater than 10,000 centipoise (cP; or 10 Pa.s) measured at original temperature in the deposit and atmospheric pressure, on a gas-free basis. Although these terms are in common use, references to heavy oil and bitumen represent categories of convenience, and there is a continuum of properties between heavy oil and bitumen. Accordingly, references to heavy oil and/or bitumen herein include the continuum of such substances, and do not imply the existence of some fixed and universally recognized boundary between the two substances. In particular, the term "heavy oil" includes within its scope all "bitumen" including hydrocarbons that are present in semi-solid or solid form.

[0013] A reservoir is a subsurface formation containing one or more natural accumulations of moveable petroleum, which are generally confined by relatively impermeable rock. An "oil sand" or "tar sand" reservoir is generally comprised of strata of sand or sandstone containing viscous petroleum, such as bitumen. Viscous petroleum, or such as bitumen, may also be found in reservoirs whose solid structure consists of carbonate material rather than sand material. Such reservoirs are

sometimes referred to as bituminous carbonates. A “zone” in a reservoir is merely an arbitrarily defined volume of the reservoir, typically characterised by some distinctive property. Zones may exist in a reservoir within or across strata or facies, and may extend into adjoining strata or facies. In some cases, reservoirs containing zones having a preponderance of heavy oil are associated with zones containing a preponderance of natural gas. This “associated gas” is gas that is in pressure communication with the heavy oil within the reservoir, either directly or indirectly, for example through a connecting water zone.

[0014] A “chamber” within a reservoir or formation is a region that is in fluid communication with a particular well or wells, such as an injection or production well. For example, in a SAGD process, a steam chamber is the region of the reservoir in fluid communication with a steam injection well, which is also the region that is subject to depletion, primarily by gravity drainage, into a production well. A very wide variety of thermal and non-thermal recovery techniques may be used to deplete zones within a reservoir, to create hydrocarbon or heavy oil depleted chambers within a reservoir.

SUMMARY OF THE INVENTION

[0015] In one aspect, the present processes utilize aspects of NCG flow management to deliver an entrained diluent/solvent liquid (DSL) to an oil interface within a reservoir, such as a heavy oil interface, with the entrained DSL then acting as a diluent or solvent to mobilize the oil for production. Detailed simulations have demonstrated the ability of NCGs to effectively sweep the entrained DSL through a formation, in a process that may be characterized as providing liquids swept along by gas (LSAG). This LSAG delivery of a solvent or diluent is effective in the absence of energetically expensive thermal inputs of the kind that characterize SAGD or VAPEX processes, with no phase change imposed on the liquid in the context of selected embodiments of the present processes.

[0016] A wide variety of DSLs may be used in LSAG processes. For example, the liquid phase of the LSAG fluid may include one or more hydrocarbon solvents, such as C3 through C10 alkanes or n-alkanes. The DSL for the LSAG fluid may be selected on

the basis that it is miscible with, and capable of enhancing the mobility of, the reservoir hydrocarbons.

[0017] In selected aspects of the present process, recovery operations may be carried out so as to set up a convective component to NCG flow within the reservoir, delivering entrained DSLs through a heavy-oil-depleted (HOD) chamber to a peripheral zone comprising an oil interface between a chamber-gas (CG) zone and heavy-oil-in-place (HOP) zone. The DSL entrained in the NCG may be injected into the reservoir through one or more injection wells, so as to deliver the liquid to the oil interface by way of a sweeping NCG flow, thereby mobilizing diluted hydrocarbons at the oil interface. The mobilized hydrocarbons then become part of a zone of mobile hydrocarbons, and the reservoir may be serviced by one or more wells mediating fluid communication between a surface completion and the zone of mobile hydrocarbons. For example, wells may be configurable to serve simultaneously or consecutively as injection and/or production wells. In this way, mobilized hydrocarbons and non-condensing gas may be recovered from the reservoir through a production well, removing heavy oil, diluent liquid and non-condensing gases from the reservoir.

[0018] In select embodiments, for example where the arrangement of wells is analogous to the arrangement of wellpairs in a SAGD process, the HOD chamber may have a longitudinal axial dimension. This longitudinal axis is typically defined by horizontal wells. For example, a generally horizontal segment of a well configured or purposed as a production well and a generally horizontal segment of an injection well. The horizontal production well is typically in fluid communication with a zone of mobile hydrocarbons, and the horizontal injection well is generally in fluid communication with the HOD chamber. The horizontal injection well may be parallel to and vertically spaced apart above the horizontal segment of the production well. In such an arrangement, a diluent liquid entrained in an NCG may be injected through the horizontal injection well at a range of selected bottom hole injection pressures that vary between injection points that are spaced apart along the length of the horizontal segment of the injection well. In this way, an axial pressure gradient may be formed within the HOD chamber from a high pressure region to a low pressure region. This axial pressure gradient may be

orchestrated so as to deliver a diluent or solvent liquid to the oil interface zone to mobilize diluted hydrocarbons. Once hydrocarbons are mobilized by mixing with the diluent or solvent liquid, the mobilized hydrocarbons may flow downwardly and towards the production well in a gravity dominated process. In conjunction with this movement of mobilized hydrocarbons, non-condensing gases in the interface zone may be mobilized. For example, the NCG may be induced to flow in the axial dimension of the HOD chamber in a convective flow motivated by an axial pressure gradient, moving from a high pressure region to a low pressure region. The mobilizing effects of this LSAG process may accordingly be arranged so as to radially expand the HOD chamber.

[0019] In alternative arrangements, injection points may be distributed on an injection well, and/or gas production points may be distributed on a production well, so that the NCG is preferentially delivered to a non-condensing gas production region of the formation. The NCG production region may for example reside in a low pressure region of the axial pressure gradient of the HOD chamber. The NCG production region may for example include one or more of gas production points.

[0020] In aspects of the LSAG process that involve an arrangement of wells analogous to a typical SAGD arrangement of wellpairs, injection wells and production wells may each include a heel segment that is proximal to a vertical segment of the well, with the heel segment and vertical well bores connecting the horizontal segments of the wells to surface completion. These wells are also typically described as having a toe segment that is spaced apart from the heel by the horizontal segment of the well. In such an arrangement, the production well may for example include one or more of gas production points in the non-condensing gas production region of the production well, and the NCG production region of the production well may be proximal to the heel segment of the production well. In select implementations of the LSAG process, an intermediate casing point of the injector well may for example be landed at a shallow angle so as to increase the vertical spacing between the heel of the injector well and the heel of the producer well. Alternatively, the production well may include one or more gas production points in the non-condensing gas production region of the production well, and the NCG production region of the production well may be proximal to the toe

segment of the production well, or intermediately spaced apart from the heel segment of the production well and the toe segment of the production well. In a further alternative well arrangement that may be used to orchestrate NCG flows, an injection well may have a sinusoidal trajectory in longitudinal cross section, with high points at the heel of the injection well and between points of non-condensing gas egress from an injector tubing into an annulus between the injector tubing and an injector casing.

[0021] Alternative implementations of the LSAG process may involve the use of one or more vent wells in the reservoir, for example in fluid communication with the HOD chamber. Vent wells may then be used for producing non-condensing gases from the vent well so as to amplify the delivery of the diluent liquid to the oil interface by way of NCG flow.

[0022] A wide variety of alternative start-up, intermediary or subsequent processes may be used in conjunction with LSAG processes. For example, a HOD chamber may be depleted of heavy oil using a thermal recovery process, such as SAGD, or a solvent-assisted process, prior to initiating a LSAG process.

BRIEF DESCRIPTION OF THE DRAWINGS

[0023] **Figure 1** is schematic illustration of a typical SAGD well pattern, showing paired injector and producer well pairs, each have a heel and a toe within the hydrocarbon rich pay zone of the formation.

[0024] **Figure 2** is a cross sectional view of an exemplary completion for an injector well, referring to the use of slotted liners, as for example disclosed in Canadian Patent Application 2,616,483 of Cenovus Energy Inc. published 29 June 2008.

[0025] **Figure 3** is a cross sectional view of an exemplary completion for a production well, in a start up configuration for circulation, illustrating an embodiment employing gas lift.

[0026] **Figure 4a** is a cross sectional view of an exemplary completion for a production well, illustrating an embodiment employing an electric submersible pump (ESP) for production operations following start up. Typically, after circulation start-up, the 2" coiled tubing string will be removed and the well equipped with a high temperature ESP capable of pumping fluid from the well into production gathering facilities.

[0027] **Figure 4b** is a cross sectional view of an exemplary completion for a production well, illustrating an embodiment that represents a completion of the type used in simulations modeling alternative embodiments.

[0028] **Figure 5** is a graph illustrating oil viscosity as a function of temperature in a computational model of alternative embodiments of the invention.

[0029] **Figure 6** is a graph illustrating the solution gas-oil ratio as function of pressure at a reference temperature of 12°C in a computational model of alternative embodiments of the invention.

[0030] **Figure 7** is a graph illustrating the oil-water relative permeability curves in a computational model of alternative embodiments of the invention.

[0031] **Figure 8** is a graph illustrating the Oil-Gas relative permeability curves in a computational model of alternative embodiments of the invention.

[0032] **Figure 9** is a ternary cross section through the steam chamber one year into a SAGD operation, where the lightest grey represents oil, intermediate shades of grey represent mobilized fluids and the darkest grey is gas. From left to right, the panels illustrate: first, **Figure 9a,** a plane where both the producer and injector are slotted; second, **Figure 9b,** a plane where the injector is blanked; and third, **Figure 9c,** a plane where the producer is blanked. The small black arrows represent the direction of gas flux.

[0033] **Figure 10** is a ternary cross section in the IK plane, slicing through the steam chamber approximately 5 years into the SAGD process, where the lightest grey represents oil, intermediate shades of grey represent mobilized fluids and the darkest grey is gas. From left to right, the panels illustrate: first, **Figure 10a,** a plane where both the producer and injector are slotted; second, **Figure 10b,** a plane where the injector is blanked; and third, **Figure 10c,** a plane where the producer is blanked. The small black arrows represent the direction of gas flux in that plane. Note the clockwise circulation of NCG near the chamber edge, with little to no flow down to the producer.

[0034] **Figure 11** is ternary cross section in the IK plane, slicing through the steam chamber near the heel of the well approximately 5 years into the SAGD process, where the lightest grey represents oil, intermediate shades of grey represent mobilized fluids and the darkest grey is gas. From left to right, the panels illustrate: first, **Figure 11a,** a plane where both the producer and injector are slotted; and second, **Figure 11b,** a plane where the injector is blanked. The small black arrows represent the direction of gas flux in the plane. Note the same clockwise circulation of NCG near the chamber edge, but with flow to the production well.

[0035] **Figure 12** is a graph, illustrating bitumen production rates under 5 simulated LSAG recovery conditions, as discussed in Example 2, with sorption coefficients (k) varying by a factor of 8000. The recovery rates are so nearly identical that the production rate data is essentially indistinguishable for the 5 different conditions.

[0036] **Figure 12** is a graph, illustrating bitumen production rates under 5 simulated LSAG recovery conditions, as discussed in Example 2, with sorption coefficients (k) varying by a factor of 8000. The recovery rates are so nearly identical that the bitumen production rate data is essentially indistinguishable for the 5 different conditions.

[0037] **Figure 13** is a graph, illustrating solvent production rates under 5 simulated LSAG recovery conditions, as discussed in Example 2, with sorption coefficients (k) varying by a factor of 8000. The recovery rates are so nearly identical that the butane solvent production rate data is essentially indistinguishable for the 5 different conditions.

[0038] **Figure 14** is ternary cross section of a simulated reservoir of Example 2, in the IK plane, slicing through the depleted heavy oil chamber, where the shades of grey represents degrees of oil depletion falling off towards the periphery of the heavy oil depleted chamber.

[0039] **Figure 15** is a graph illustrating data from Example 2, showing bitumen production rates for a LSAG process (Aerosol Bitumen) compared to bitumen production rates for a SAGD and for a Solvent Aided Process (SAP).

[0040] **Figure 16** is a graph illustrating data from Example 2, showing the cumulative steam-oil ratio (CSOR) for a LSAG process (Aerosol CSOR) compared to the CSOR for a SAGD process (SAGD CSOR) and for a Solvent Aided Process (SAP CSOR).

[0041] **Figure 17** is a graph illustrating data from Example 2, showing the course of injection and production rates of various fluids in the course of a LSAG process throughout the operating period. Steam injection takes place initially, as part of the start-up process, and then ends. Bitumen production is relatively steady throughout the process. Injected DSL ("Suspended Solvent") is essentially all recovered ("Produced Solvent"). NCG injection increases over the course of the operation ("Aerosol Gas (Propellant)").

DETAILED DESCRIPTION OF THE INVENTION

[0042] Processes are provided for delivering a diluent/solvent liquid (DSL) to a hydrocarbon deposit, such as a heavy oil, using a non-condensing gas (NCG). The liquid is swept along by the gas (LSAG), with the liquid being interchangeably characterized as entrained, dispersed or suspended in the NCG. In this way, the oil is mobilized by mixing with the DSL, so that the mobilized oil migrates, for example by gravitation or by another form of displacement, to a production well. These processes may accordingly involve forms of gravity drainage and/or convective mobilization in the context of in situ recovery processes, with the flow of two-phase LSAG fluid distributing the DSL to the oil-in-place.

[0043] The LSAG fluid is a combination of the DSL and NCG, and this combination may be provided using a variety of operational approaches. For example, the DSL may be introduced to the reservoir in selected volumes, or slugs, alternating with the sequential introduction of the NCG. The timing and volume of these sequential fluid introductions may be managed so as to provide the desired LSAG flow. Alternatively, the DSL and NCG may be introduced simultaneously, with mixing of the two phases occurring prior to or during introduction of the LSAG fluid to the reservoir. The LSAG fluid may accordingly be formed prior to entering an injection well, or within the wellbore, or after the NCG and DSL constituents separately exit the wellbore and then amalgamate to form the LSAG fluid. These approaches may also be used in combination. For example, it may be appropriate to form the DSL from multiple constituents at the surface, with suspension or dispersion of the DSL in the gas phase occurring at one or more other points in the process of introducing the LSAG fluid to the reservoir. In accordance with the foregoing, as used herein "entrainment" refers to a relationship among flowing fluids, such as an NCG and a DSL, whereby the flow path of one fluid, such as the NCG, directs or influences the direction of the flow path of the other fluid, such as the DSL. Thus, entrainment can include configurations wherein the DSL is suspended or dispersed or intimately distributed within the NCG, as with an NCG/DSL aerosol or spray. Alternatively, in keeping with the reciprocal influence on flow paths, entrainment can include concurrent or sequential volumes, or slugs, of NCG and DSL.

[0044] The mixing of the DSL and NCG may involve atomization, for example the formation of a spray or aerosol, with the DSL forming droplets as the discontinuous liquid phase within the continuous NCG gas phase. The LSAG fluid may accordingly be formed by a variety of liquid-in-gas dispersions, such as sprays of gas-suspended liquid particles. LSAG fluid sprays may for example be defined as having liquid particle diameters that are generally greater than about 10 microns. In some implementations, the LSAG fluid may form an aerosol, with DSL droplets in the micron to submicron size range that are sufficiently small that Brownian motion tends to maintain the DSL droplets in suspension within the NCG gas phase (Tien and Payatakes, 1979; Richard

Hall, May 2013, Ph.D. Thesis, Clemson University, Numbered 1-1-2013, "Aerosol Delivery as a Method for Enhancing Remedial Application in Contaminated Vadose Zones"). In selected embodiments, techniques may be used to stabilize DSL droplets within the LSAG fluid, for example by imposing or facilitating the existence of an electrical charge on the droplets, as for example has been described in the context of aerosols (Vonnegut, et al., Research in Electrical Phenomena Associated with Aerosols, Quarterly Report No. 4, April 15 – July 15, 1961, Contract DAI8-108-405-Cml-852, Arthur D. Little, Inc.). For example, droplets which exit an atomizer may be spontaneously charged, or a charge may be imposed for example by impact on a surface or by application of an electric field, ionizing radiation or coronal discharge.

[0045] The LSAG fluid flow may be orchestrated so that broad distribution of the DSL within the reservoir is mediated by the managed NCG flow within the porous medium of the reservoir. In this context, it will be understood that the phase characterizations of the LSAG fluid flow, such as "liquid phase" and "gas phase" and "NCG" are used herein to describe aspects of LSAG fluid dispersion. However, it will be appreciated that LSAG fluid flows within the reservoir take place in the context of complex phase equilibria, with thermodynamic parameters dictating continuous phase changes within the LSAG fluid, so that these phase characterizations are not absolute. For example, a portion of any particular liquid phase, such as the DSL, will enter the gaseous phase in equilibrium with a surrounding gas phase, such as the NCG, so that the gas phase may for example be saturated with vapour phase of the entrained liquid. Accordingly, in selected embodiments, the characterization of the DSL as a liquid, and the NCG as a gas, reflects that fact that these phase characteristics apply to the isolated DSL and NCG fluids over the relevant range of reservoir temperatures and pressures.

[0046] The DSL may mobilize viscous hydrocarbons by a variety of mechanisms, for example by being miscible with the hydrocarbons so as to reduce viscosity, and/or by affecting properties such as the interfacial tension of the viscous hydrocarbons. These mechanism do not require the imposition of a phase change on the DSL, in contrast for example to thermal recovery mechanisms such as SAGD or VAPEX.

[0047] Various aspects of the invention involve the use of a non-aqueous or organic solvent or diluent as the DSL, such as a straight or branched chain, cyclic or aromatic hydrocarbon, such as a C3 to C8 alkane, particularly n-alkanes or mixtures thereof. These DSLs may for example include one or more C3 to C10 linear or cyclic alkanes, alkenes, or alkynes, in substituted or unsubstituted form, or other aliphatic or aromatic compounds. Substituents may for example include organic substituents or heteroatoms such as halogens. The DSL component or mixture of components may be selected so that it will exist substantially in liquid form at recovery process conditions within the reservoir, thereby facilitating its eventual drainage by gravity, along with, or when mixed with, mobilized oil. Selected embodiments use n-butane as the DSL, or as the primary constituent of the DSL. In alternative embodiments, a mixture of solvents may be selected such that the mixture approximates the properties of a selected solvent, such as butane, such as the density-increasing and/or viscosity-reducing properties of butane. The DSL may for example be selected so that when mixed with a particular bitumen in a reservoir at a desired ratio it confers a target density on the resulting mobilized heavy oil mixture. The DSL may also include a variety of additives, such as: a surface active agent (capable of modifying the interfacial tension of liquids), an emulsifier, a foaming or defoaming agent, a polymer, solid particulate matter or a microbial agent (such as one or more bacterial or viral cultures, which is capable of modifying the resident reservoir fluids so that mobility of the resident hydrocarbons is increased). The DSL may also be in a variety of physical forms and various stages of the process, such as an emulsion or a foam.

[0048] The NCG component of the LSAG fluid may for example be one or more oxidizing or non-oxidizing gases or mixtures thereof. Examples of NCGs which are non-oxidizing include natural gas, stoichiometric exhaust (flue) gas, methane, nitrogen, and carbon dioxide. Examples of non-condensing gases which are oxidizing, or potentially oxidizing, include air, enriched air, and oxygen. The NCG phase may be initially constituted in various degrees of phase equilibrium with the DSL, for example being supersaturated or fully saturated or partially saturated or totally unsaturated.

[0049] In alternative embodiments, the injected LSAG fluid may include a selected amount of DSL, in combination with an NCG carrier gas, for example (by weight) 1%-50%, 10%-40%, 20%-30% or about 25%. The relative amount of DSL may alternatively be below an upper limit, for example up to 50%, 40%, 30%, 20%, 10% or 5wt% by weight; and/or above a lower limit, such as below 50%, 40%, 30%, 20%, 10% or 5wt% by weight; or within any range defined by these upper and lower limits.

[0050] LSAG recovery techniques may be employed at a variety of stages within the recovery process, alone or in combination with other recovery techniques. For example, LSAG recovery may be initiated at start-up, with the reservoir in a pre-development stage (original conditions of temperature and pressure). Alternatively, LSAG recovery may be initiated under post start-up conditions, following a prior recovery process or other reservoir treatment. In addition, LSAG recovery techniques may be applied on a local (i.e., near-wellbore) basis, or throughout the reservoir. LSAG recovery may accordingly constitute one or more of the start-up, ramp-up, operational, or blowdown phases of a recovery process, alone or in combination with other techniques or phases (such as the processes described in the Background). With respect to final stages of recovery, LSAG processes may involve a DSL recovery step following hydrocarbon recovery operations, to recover injected DSLs that remain in the reservoir. This may for example involve de-pressuring the reservoir, injection of a DSL-dry NCG, introduction of alternative heated fluids, or heating via electrical means.

[0051] The characteristics and constituents of the LSAG fluid may be varied over time during the course of a recovery process. For example, the size of the DSL droplets may be varied, or the relative amount of the DSL in the LSAG fluid may be adjusted, and the chemical components of the DSL and/or the NCG may be varied, for example from one stage of recovery to another.

[0052] LSAG processes may be designed to involve aspects of gravity-dominated fluid flow. For example, the buoyancy of the LSAG fluid may be tailored to propel the injected LSAG fluid upwardly, on a trajectory that brings the LSAG fluid into contact with resident viscous hydrocarbons along an ascending path. In turn, the constituents of the

DSL may be selected so that, when the DSL droplets adhere to and mix with resident hydrocarbons, mobilizing the viscous hydrocarbons, the mobility of those hydrocarbons will be increased, and the density of the mobilized hydrocarbons adjusted, so that they drain downwardly to a receiving point, such as a production well. Alternatively, or additionally, an LSAG recovery process may be tailored to involve selected convective flow regimes, instead of or in addition to gravity-dominated flows. In these circumstances, the path of the LSAG fluid within the reservoir may for example include a major horizontal or lateral component of flow.

[0053] LSAG processes may be cyclic, in the sense that the LSAG fluids are introduced into the reservoir periodically. For example, an LSAG fluid may be introduced and allowed to soak within the reservoir for a period of time, with no or reduced fluid production from the reservoir, and then reservoir fluid production may be revived. Cyclic process may for example involve a single well acting sequentially as both injector and producer, or an aggregate of such single wells. Alternatively or additionally, a cyclic LSAG process may be operated in which the LSAG fluid is introduced at an injection wellbore while a nearby production well is shut in. Following a period of LSAG fluid injection, the injection well may be shut in. Finally, one or more production wells may then be opened to production of mobilised fluids. In a further variation, LSAG fluid injection may be alternated with injection of other fluids. For example, injection of a defined quantity of one or more LSAG fluids may be followed by a period of injection of different fluids, such as an NCG alone, in a manner that uses the dry NCG to sweep previously injected DSL fluids into the reservoir. In these cyclic or alternating processes, the chemical composition, quantity, duration, and conditions of state of the alternating injection fluids may be varied widely.

[0054] Various aspects of the invention involve the drilling of one or more wells that are situated and operated so as to form a hydrocarbon extraction chamber within a reservoir. This may for example include well pairs within a reservoir 11, as illustrated in **Figure 1**, in a pattern that is typically used with SAGD, with each injector well 13, 19, 23, paired with a corresponding producer well 15, 17 and 21. In this illustrative arrangement, each well has a completion 14, 12, 16, 18, 20 and 22 on surface 10, with

a generally vertical segment leading to the heel of the well, which then extends along a generally horizontal segment to the toe of the well. In very general terms, to provide a general illustration of scale in selected embodiments, these well pairs may for example be drilled in keeping with the following parameters. There may be approximately 5 m depth separation between the injection well and production well. The well pair may for example average approximately 800 m in length. The lower production well profile may generally be targeted so that it is approximately 1 to 2 m above the reservoir base. As discussed in more detail below, the development of hydrocarbon extraction chambers around each well pair may be illustrated in cross sectional views along axis 24, which is perpendicular to the longitudinal axial dimension of the horizontal segments of the well pairs. A wide variety of alternative arrangements of wells are also available, for example well pairs may be used with wedge or infill wells, and the injector and/or producer wells may be branches of a multilateral well, for example cooperative multilateral wells or "fishbone" multilateral wells. In alternative embodiments, rather than using a well pair, one or more single horizontal, inclined or vertical wells may be used for injection and/or production and/or venting, thereby adjusting the pattern of LSAG fluid flow and associated fluid displacement geometries. Wells may accordingly be configured in a wide variety of operational roles, so that the characterization of a well as being configured for a particular role, such as injection or production, is indicative of the purpose that the well serves rather than any specific mechanical or topological feature of the well.

[0055] Selected aspects of the LSAG process may involve the operational control of wells, so that the wells function in alternative roles as either sources or sinks, for NCGs or DSLs. For example, an accumulation of a dry NCGs in a region may interfere with mobilization of hydrocarbons. To counteract this effect, additional wells, such as vent wells, may be placed at strategic points in the reservoir so that a portion of the NCG can be siphoned off or produced. The produced gas may include some DSL, and the produced gas may accordingly be processed to remove excess liquids, with recycling of the processed gas as NCG carrier gas, and recycling of the recovered liquids as DSL.

[0056] In alternative embodiments, recovery processes of various kinds may be combined, for example with thermal start-up recovery processes being used sequentially with processes described herein, including but not limited to, SAGD and/or alternative solvent aided processes (SAP), and/or "huff and puff" processes. For example, CA 2,844,345 to Gittins, discloses a thermal/solvent oil recovery process for producing hydrocarbons using a single vertical or inclined well. In particular embodiments, LSAG processes may be preceded by alternative start-up acceleration techniques, for example to establish communication in the formation between an injection means and a production means within the single well, or between injection and production wells. Alternatively, LSAG processes may be used as an initial reservoir conditioning or start-up process, to be following by subsequent recovery processes. In select embodiments, thermal techniques may for example be used within, or in the vicinity of, production wells, to increase the temperature in the region of the production well and thereby avoid the formation of pore-plugging gas hydrates (clathrates). Similarly, periodic thermal pulses may be used in conjunction with LSAG processes, to clear clathrates from other portions of the reservoir.

[0057] In the case of single well embodiments, fluid communication refers to fluid flow in the formation between the injection means (or an injection component) and the production means (or a production component) in the single well. For example, the injection and production components may be conduits, optionally tubing, and may be isolated from one another by way of a packer, by positioning the injection and production means a suitable distance apart, by varying the geometry of the tubulars within the wellbore, by positioning the injection means in the wellbore closer to the surface than the production means in the case of a vertical well, or by way of openings or perforations in the tubing or well casing over selected wellbore interval(s) to permit both outlet of injected fluids and inlet of production fluids. The positioning of the injection and production means may be adapted depending on the particular well and formation. For example, processes may make use of an injection tubing string which has openings only at or towards one end of the horizontal well, for example at the toe end, to permit egress of injected fluids, and openings or perforations along the liner or outer casing of the wellbore to permit injection into the reservoir of mobilizing fluids over a selected

interval of the wellbore. Positioned downstream therefrom along the casing or liner of that same wellbore, openings may be provided to permit production from the reservoir of mobile and mobilized fluids. In addition, one or more surfactants can be used to facilitate or accelerate a single well start-up process, or to improve fluid communication.

[0058] Alternative aspects of the invention involve completing wells in various configurations. Exemplary completions for injector, producer on gas lift, producer on electronic submersible pump (ESP) and simulated producer are shown in **Figures 2, 3, 4a and 4b** respectively.

Example 1: NCG Flow Management

[0059] In accordance with various aspects of the invention, detailed computational simulations of reservoir behaviour have been carried out. An initial set of simulations illustrates various aspects of NCG flow management, illustrating that the flow of NCGs may be orchestrated using a wide variety of operational tools, for example by imposing pressure gradients within a reservoir. A further set of simulations illustrates that NCG flow management may be used to deliver an entrained liquid to a heavy oil interface within a reservoir, with the entrained liquid then acting as a diluent or solvent to mobilize the heavy oil for production. These detailed simulations have demonstrated the ability of NCGs to effectively sweep the entrained liquid through a formation, in a process that may be characterized as providing liquids swept along by gas (LSAG).

Simulation Grid for NCG Flow Management Modeling

[0060] A half element of symmetry was employed to ensure faster run times. The model had 30 m pay, 3 m bypassed pay and an 800 m long well. There was 31 m of overburden and 31 m underburden. Grid dimensions were 26 x 64 x 43, for a total of 71,552 blocks. Block dimensions were as follows:

I – direction: 1m 24*2m 1m (26 blocks, total length of 50 m)

J – direction: 64*12.5m (64 blocks, total length of 800 m)

K – direction: 16 m 8 m 4 m 2 m 35*1 m 2 m 4 m 8 m 16 m (43 blocks, total length of 95 m)

[0061] The high level of discretization in the J direction was done to model the blanking and slotting of casing joins. A typical casing joint is approximately 12-13 m in length.

Reservoir Properties for NCG Flow Management Modeling

[0062] The grid was populated using the following reservoir variables:

Temperature = 12 °C

Φ = 0.33

Kh = 7.0 D

Kv = 4.2 D

Reference pressure of 2,400 kPa at the top of the SAGD pay

Sw = 0.215

So = 0.785

Mass Fraction Oil of Dead Oil = 0.85

Mass Fraction Oil of CH4 = 0.15

[0063] The thermal properties of the reservoir were characterized using two rock types. Rock type one represented clean sand and was used to populate a selected pay, representing the McMurray formation in Alberta, Canada (within the Mannville Group in the Western Canadian Sedimentary Basin). A second rock type representing shale was used to populate the over and underburden grid. The properties of the two rock types were defined with the following properties:

Rocktype 1 (Sand)

Porosity Reference Pressure = 100 kPa

Compressibility = 1e-6 1/kPa

Volumetric Heat Capacity 2.39e6 J/(m^3*C)

Rock Thermal Conductivity = 196,820 J/(m*day*C)

Water Thermal Conductivity = 552,960 J/(m*day*C)

Oil Thermal Conductivity = 0

Gas Thermal Conductivity = 0

Rocktype 2 (Shale Overburden & Underburden)

Porosity Reference Pressure = 100 kPa

Compressibility = 1e6 1/kPa

Volumetric Heat Capacity 2.39e6 J/(m^3*C)

Rock Thermal Conductivity = 146,880 J/(m*day*C)

Water Thermal Conductivity = 0

Oil Thermal Conductivity = 0

Gas Thermal Conductivity = 0

PVT Data for NCG Flow Management Modeling

[0064] The PVT model consisted of three components; water, dead oil and methane, with characteristics as illustrated in **Figures 5 and 6**.

Relative Permeability for NCG Flow Management Modeling

[0065] The oil-water relative permeability curves have the following properties:

Connate Water Saturation = 0.2

Critical Water Saturation = 0.2

Residual Oil Saturation = 0.15

Irreducible Oil Saturation = 0.15

Max relative water permeability = 0.559

Max relative oil-water permeability = 0.95

[0066] The oil-gas relative permeability curves have the following properties:

Critical Gas Saturation = 0.05

Residual Liquid Saturation = 0.3

Max relative gas permeability = 0.72

Max relative oil-gas permeability = 0.95

[0067] Relative permeability properties are illustrated in **Figures 7 and 8**.

Operating Constraints for NCG Flow Management Modeling

[0068] The simulation was initiated with a circulation phase in order to establish inter wellpair communication. Four numerical wellbore models (Flexwells™) were used to mimic the operation of the SAGD well pairs during this phase. Circulation lasted for 2 months and used the following parameters and constraints for well definition and operation:

Producer Annulus (Producer Well)

Min Bottom Hole Pressure = 5,100 kPa

ID = 0.159m

OD = 0.178m

Producer Circulation Tubing String (Injector Well)

Max Water Rate = 150 m^3/d

Max Bottom Hole Pressure = 8,600 kPa

ID = 0.078

OD = 0.089

Injector Annulus (Producer Well)

Min Bottom Hole Pressure = 4,900 kPa

ID = 0.159

OD = 0.178

Injector Coil Tubing (Injector Well)

Max Water Rate = 150 m^3/d

Max Bottom Hole Pressure = 8,600 kPa

ID = 0.04

OD = 0.045

[0069] As exemplified, the SAGD operational phase begins after circulation, takes place at low pressure and lasts until the start of blow down. During this period, three numerical wellbore models were defined, with completions analogous to that shown in **Figure 4b**, with the following parameters and constraints in order to mimic SAGD well pair operation:

Injector Annulus (Shutin)

ID = 0.159

OD = 0.178

Injector Tubing String (Oprn)

ID = 0.104

OD = 0.134

Injector liner block 1, 1, 14 kept at 2,600 kPa via trigger

Injector Tubing String (Injector Well)

Max Bottom Hole Pressure initiated at 2,900 kPa, but later defined via trigger

Max Water Rate = 1,200 m^3/d

Tubing has 3 steam splitters at 131 m, 331 m and 581 m

1st Sub: 1 cm diameter holes, 0.8 discharge coefficient, 6 holes

2nd Sub: 1 cm diameter holes, 0.8 discharge coefficient, 12 holes

3rd Sub: 1 cm diameter holes, 0.95 discharge coefficient, 32 holes

Producer Annulus (Producer Well)

Max Liquid Rate = 200 m^3/d

Min Bottom Hole Pressure = 1,900 kPa

Max Steam Production = 10 m^3/d CWE

[0070] Simulations carried out with the foregoing parameters to illustrate aspects of NCG flow management illustrated that for the first year and half of a typical SAGD operational period, gas flow follows a relatively consistent pattern as illustrated in **Figure 9**. Liberated NCG migrates from its place of origin to the top and edges of the steam chamber, where it accumulates and is eventually drawn down along the chamber wall to the production well. As an illustration of NCG flow management, it was found that blanking or slotting the production and injection liner joints can significantly alter gas flow. When both joints are slotted the gas behaves as previously described, flowing down the chamber wall to the production well. Blanking an injection joint will alter the flow of gas so that it flows down towards the producer along the chamber wall and through the center of the chamber. The lack of injection prevents steam from displacing the NCG and carrying it towards the chamber boundaries, simultaneously creating a plane of lower pressure relative to the surrounding regions. This promotes the backflow of gas into the chamber and down to the producer. When a joint in the production well is

blanked, no production occurs at this location. NCG and any other fluids are forced to move parallel to the well pair in order to locate a slotted joint for production.

[0071] These flow regimes exemplify means of orchestrating fluid production in the context of selected reservoir conditions. For example, regions where both the injector and producer are slotted may be used to act as regions for removing NCGs. Computational modeling indicates that, under certain reservoir conditions, there is little to no NCG flow where the producer has been blanked, with gas traveling down the depletion chamber wall for production where the producer is slotted and down both the chamber wall and through the chamber where the injector is blanked.

[0072] Simulations indicate that under selected conditions the NCG flow regime begins to alter in a SAGD process as the steam chamber expands, for example at approximately 2 years into the process as simulated, reflecting changes that may occur on alternative time lines in alternative reservoir conditions. These simulations demonstrate that NCG productivity of any slotted producer joints not near the heel may begin to diminish, with the opposite being true of any producer slotted joints near the heel.

[0073] In a mature SAGD system, simulations indicate that NCG continues to accumulate at the chamber wall along the entire length of the wellpair. However, cross sections perpendicular to the wellpair show that the majority of NCG is in a holding pattern at the wall of the chamber. NCG is liberated or generated at the bitumen steam interface, drawn down to the bottom of the chamber wall, where it reverses directions and rises back to the top of the chamber. **Figure 10** demonstrates that this cycle is repeated regardless of whether or not the injector or producer is slotted or blanked.

[0074] The foregoing modeling is illustrative of techniques for predicting and managing NCG flows. For example, a selected pattern of completions may give rise to NCGs flowing towards the heel of a wellpair to be drawn down into a production well. The efficiency of gas production at the heel may accordingly be adjusted by the completion design of the injection well. For example, regions where the production well

is slotted, but the injector is blanked, may be used to produce more gas than those where both wells are slotted, as illustrated in **Figure 11**.

[0075] In view of the foregoing understanding of NCG flows within a reservoir, the recovery processes described herein provides a number of modifications that can be made to injection and production systems in order to orchestrate NCG flows for the purpose of recovery processes using LSAG. In selected embodiments, LSAG processes involve arranging the locations of fluid injection to improve delivery of entrained liquids by NCG mobilization.

Alternative LSAG Systems

[0076] A number of variations on typical SAGD techniques may be implemented to orchestrate LSAG recovery processes, as described below. These approaches are not mutually exclusive, and any combination of these approaches may be combined in alternative arrangements.

Adjusting the Number of Blank Joints at the Injector's Heel

[0077] LSAG systems may involve increasing the number of blanked injector joints and/or slotted production joints near the heel of a wellpair, to adjust fluid flows within the reservoir so as to deliver entrained liquids to an interface with heavy oil in place. For example, joints at the injector's heel, which may be slotted in the typical SAGD operation, may be blanked in various combinations.

High Injector Landing or Low Producer Landing

[0078] In this arrangement, the injector's intermediate casing point (ICP) is landed at a shallower angle higher in the reservoir, so that the heel of the injector well is in effect elevated and spaced further apart vertically from the heel of the producer well. For example, the injector's ICP may be landed at 86 degrees and several meters above the targeted final depth of the horizontal portion of the injector well. Alternatively, the heel of the production well may be landed lower in the formation. For example, the producer's ICP may be landed at a shallower angle lower in the reservoir, so that the heel of the injector well is in effect elevated and spaced further apart vertically from the heel of the

injector well. In alternative arrangements, this may be done so as to locate the ESP outside of the productive pay, which may help to prevent gases from flowing directly to the ESP.

Sinusoidal Injector or Producer Trajectory

[0079] In this arrangement, an injection well may be drilled in a manner mimicking a sinusoidal wave. High spots in the well being located at the heel and between points of fluid egress from the tubing into the annulus between the tubing and the casing. Alternatively, the producer well may be drilled in a manner mimicking a sinusoidal wave, for example with low spots located at the heel and between points of fluid egress at the injection well.

Vent Wells

[0080] In this arrangement, one or more NCG vent wells may be provided within the reservoir to facilitate NCG mobilization. In alternative embodiments, vent wells may have a wide variety of locations and orientations, for example including vertical and/or horizontal segments. Horizontal segments of vent wells may for example be orientated at a strike of 0 to 90 degrees to a selected wellpair, i.e. parallel, perpendicular or at any intermediate angle. The trajectory of vent wells may also be varied, so that the vent wells are not limited to being flat or of one continuous elevation. In selected implementations, the vent wells may have a generally horizontal trajectory parallel to a wellpair, and the vent wells may be drilled from the surface. In alternative implementations, vent wells may for example be drilled as a multilateral branch from an injection well. In some vent well completions, inflow control devices (ICDs), or any other means to restrict or prevent gas flow in that section of the wellbore, may for example be used to control inflow. These variables may for example be adjusted so as to orchestrate NCG mobilization in a pattern that is conducive to LSAG delivery of liquids to a heavy oil interface.

Example 2: LSAG Recovery Process

[0081] This Example illustrates the simulated results of injecting a DSL entrained in an NSG as an LSAG fluid in a viscous hydrocarbon (i.e., oil sand) reservoir. To illustrate

the robustness of the DSL fluid distribution under varying conditions, the simulations included five dramatically different sorption coefficients spanning a range of values which differed by a factor of 8000. The LSAG fluid consisted of methane as the NCG and butane as the DSL.

[0082] As illustrated in **Figures 12 and 13**, production performance was essentially identical in all five cases. Specifically, the oil rates (**Figure 12**) and solvent return rates (**Figure 13**) were virtually identical. Details of the reservoir properties, well configuration and performance results follow.

[0083] For simulation purposes, the type of reservoir into which the aerosol was injected was a typical rich oil sand reservoir, such as that commonly found in the McMurray Formation of northeastern Alberta. A summary of salient reservoir characteristics and basic well orientation data is provided in Table 1. A half symmetry, live oil model was used. Block sizes were one meter in the x and z direction and 800 meters in the y-direction.

TABLE 1: Reservoir Characteristics and Well Orientation

Oil sand thickness	20m
Porosity	33%
Horizontal permeability	6.0 D
Vertical permeability	4.2 D
Initial bitumen saturation	80%
Initial water saturation	20%
Vertical distance between horizontal injector and producer	5m
Horizontal distance between well pairs	100m

[0084] A gravity-dominated recovery process operating in an oil sand was simulated, analogous to SAGD in terms of production and injection well configuration. In keeping with that approach, the vertical separation between the two horizontal wells was five metres. The simulations were carried out in 2D.

[0085] In anticipation of a large accumulation of NCGs within the reservoir as a result of LSAG fluid injection, the well configuration for this embodiment also included a series of vent wells completed near the top of the reservoir to siphon off excess gas. This well configuration is illustrated in **Figure 14**, which also provides a snapshot of the bitumen saturation at a point in time during the course of the LSAG fluid injection process. The vent wells were configured so that wells that are further from the injection point had lower production pressure and thus no short circuiting of gases occurred.

[0086] Following the application of a three-month start-up sequence in common use in oil sands in situ recovery operations to establish communication between the overlying horizontal injection well and the underlying horizontal producing well, LSAG fluid injection was initiated at the injector. The LSAG fluid consisted of 75 weight % methane gas as the continuous phase and 25 weight % butane as the dispersed liquid droplet phase. In this illustrative embodiment, no thermal agents were introduced into, or induced within, the reservoir during the course of the LSAG production process.

[0087] Performance results demonstrate that the LSAG fluid aerosol is effective in contacting and mobilizing viscous hydrocarbons and in facilitating bitumen production. This is illustrated in **Figure 15** which compares bitumen production rates for the subject invention to the corresponding rates for a SAGD process and for a Solvent Aided Process (SAP), both of which are thermal steam-based processes. Note that the oil production curve for SAGD and SAP stops when SAGD reaches 70% recovery. For SAP, butane was used as the solvent and was injected at 10wt% along with steam. In all cases maximum injection pressure was 2500kPa. The agglomeration and adsorption of LSAG fluid droplets into the continuous oleic phase was modeled using a first-order reaction as in Equation 5-8 in [Aerosol Delivery as a Method for Enhancing Remedial Application in Contaminated Vadose Zones, Richard Hall, Clemson University, 2013].

[0088] As indicated, bitumen production rates are lower for the LSAG process than for the two thermal alternatives, although cumulative bitumen production levels are comparable. However, as one would expect, and as illustrated in **Figure 16**, the

cumulative steam-oil ratio (CSOR) is dramatically lower in the case of the aerosol LSAG process. **Figure 17** illustrates the course of injection and production rates of the subject invention throughout the operating period, and shows that a very large percentage of the injected solvent is recovered during production.

[0089] The relative uniformity of outcomes, irrespective of the choice of sorption coefficient in each simulation run, illustrates that effective recovery of bitumen resources may be achieved using a very wide variety of LSAG fluids and operational parameters.

Conclusion

[0090] Although various embodiments of the invention are disclosed herein, many adaptations and modifications may be made within the scope of the invention in accordance with the common general knowledge of those skilled in this art. For example, any one or more of the injection, production or vent wells may be adapted from well segments that have served or serve a different purpose, so that the well segment may be re-purposed to carry out aspects of the invention, including for example the use of multilateral wells as injection, production and/or vent wells. Such modifications include the substitution of known equivalents for any aspect of the invention in order to achieve the same result in substantially the same way. Numeric ranges are inclusive of the numbers defining the range. The word "comprising" is used herein as an open-ended term, substantially equivalent to the phrase "including, but not limited to", and the word "comprises" has a corresponding meaning. As used herein, the singular forms "a", "an" and "the" include plural referents unless the context clearly dictates otherwise. Thus, for example, reference to "a thing" includes more than one such thing. Citation of references herein is not an admission that such references are prior art to the present invention. Any priority document(s) and all publications, including but not limited to patents and patent applications, cited in this specification are incorporated herein by reference as if each individual publication were specifically and individually indicated to be incorporated by reference herein and as though fully set forth herein. The invention includes all embodiments and variations substantially as hereinbefore described and with reference to the examples and drawings.

CLAIMS

1. A process for removing fluids from a hydrocarbon reservoir, the reservoir being serviced by one or more wells, configurable as injection or production wells, mediating fluid communication between a surface completion and the reservoir, the process comprising:

a) injecting into the reservoir a combination or sequence of fluids comprising a diluent/solvent liquid (DSL) with a non-condensing gas (NCG), through a well configured as an injection well, so as to deliver the DSL entrained in the NCG to an oil interface zone by way of a liquid swept along by gas (LSAG) fluid flow, thereby mobilizing oil by mixing of the oil and the DSL at the oil interface,

b) recovering fluids through a well configured as a production well, thereby removing mobilized oil, DSLs and NCGs from the reservoir.

2. The process of claim 1, wherein a single well is sequentially configurable as the injection well and the production well.

3. The process of claim 1, wherein a plurality of wells are provided, and separate wells are configured to cooperate as the injection well and the production well.

4. The process of any one of claims 1 to 3, further comprising a step of atomizing the DSL within the NCG, so that the LSAG flow comprises atomized DSL.

5. The process of claim 4, wherein the step of atomizing takes place at least partly within the reservoir.

6. The process of claim 4, wherein the step of atomizing takes place at least partly prior to introducing the DSL and the NCG into the reservoir.

7. The process of any one of claims 4 to 7, wherein the atomized DSL is produced as a spray.

8. The process of any one of claims 4 to 7, wherein the atomized DSL is produced as an aerosol.

9. The process of any one of claims 1 to 8, comprising injecting the NCG and the DSL into the reservoir sequentially.

10. The process of any one of claims 1 to 9, comprising injecting the NCG and the DSL into the reservoir concurrently.

11. The process of any one of claims 1 to 10, wherein the NCG comprises an oxidizing gas.

12. The process of any one of claims 1 to 11, wherein the NCG comprises a non-oxidizing gas.

13. The process of any one of claims 1 to 12, wherein the NCG comprises methane.

14. The process of any one of claims 1 to 13, wherein the DSL and NCG are in phase equilibrium in the LSAG fluid flow.

15. The process of any one of claims 1 to 14, wherein the DSL comprises an organic DSL that is liquid at reservoir temperatures and pressures and is miscible with oil resident in the reservoir.

16. The process of any one of claims 1 to 15, wherein the DSL comprises a hydrocarbon DSL.

17. The process of claim 16, wherein the hydrocarbon DSL comprises a C3 to C10 alkane.

18. The process of any one of claim 1 to 17, wherein produced NCG is recycled and re-injected into the reservoir.

19. The process of claim 18, wherein the NCG is processed to remove a constituent of the produced NCG before being re-injected into the reservoir.

20. The process of any one of claim 1 to 19, wherein produced DCL is recycled and re-injected into the reservoir.

21. The process of claim 20, wherein the DSL is processed to remove a component of the produced DSL before being re-injected into the reservoir.

22. The process of any one of claims 1 to 21, wherein the mobilized oil is displaced principally by a gravity driven process.

23. The process of any one of claims 1 to 21, wherein the mobilized oil is displaced principally by convective displacement.

24. The process of any one of claims 1 to 23, wherein the injection of the DSL and the NCG is cyclic.

25. The process of claim 24, wherein the cyclic injection of the DSL and the NCG is alternated with injection of a dry NCG having a reduced or no DSL content.

26. The process of any one of claims 1 to 25, further comprising a step of heating the reservoir.

27. The process of any one of claims 1 to 26, further comprising an additive in the DSL, wherein the additive is a surface active agent, an emulsifier, a foaming agent, a defoaming agent, a polymer, a solid particulate or a microbial agent.

28. The process of any one of claims 1 to 27, wherein the injection and recovering steps comprise concurrent injection and recovering steps.

29. The process of any one of claims 1 to 28, wherein the injection and recovering steps comprise sequential injection and recovering steps.

30. The process of any one of claims 1 to 29, further comprising a temporally distinct alternative recovery process in the reservoir, carried out before or after or sequentially with the injection and recovering steps.

31. The process of claim 30, wherein the alternative recovery process comprises a thermal recovery process.

32. The process of claim 31, wherein the thermal recovery process comprises a steam assisted gravity drainage (SAGD) process.

33. The process of claim 31 or 32, wherein the thermal recovery process comprises a solvent-assisted process.

34. The process of any one of claims 1 to 33, further comprising a start-up dilation process prior to the injecting and recovering steps.

35. The process of any one of claims 1 to 34, further comprising imposing an electric charge on droplets of the DSL.

36. The process of any one of claims 1 to 35, wherein the reservoir comprises a heavy-oil-depleted (HOD) chamber having a peripheral zone comprising the oil interface zone and the LSAG flow carries the DSL through the HOD chamber.

37. The process of claim 36, wherein the HOD chamber has a longitudinal axial dimension formed by:

i) a generally horizontal segment of a well configured as a production well that is in fluid communication with the zone of mobile hydrocarbons;

ii) a generally horizontal segment of an injection well that is in fluid communication with the HOD chamber, generally parallel to and vertically spaced apart above the horizontal segment of the production well.

38. The process of claim 37, wherein the DSL entrained in the NCG is injected through the horizontal segment of the injection well at a range of selected bottom hole injection pressures that vary between injection points that are spaced apart along the length of the horizontal segment of the injection well, so as to form an axial pressure gradient within the HOD chamber from a high pressure region to a low pressure region, so as to concurrently:

i) deliver the DSL to the oil interface zone to mobilize diluted hydrocarbons, so that the mobilized hydrocarbons flow downwardly and towards the production well in a gravity dominated process;

ii) mobilize NCG in the oil interface zone, so that the NCG flows in the axial dimension of the HOD chamber in a convective flow motivated by the axial pressure gradient, moving from the high pressure region to the low pressure region; and,

iii) radially expand the HOD chamber.

39. The process of claim 38, further comprising arranging injection points on the injection well and one or more gas production points on the production well, so that the NCG is preferentially delivered to a NCG production region of the formation that resides in the low pressure region of the axial pressure gradient of the HOD chamber, the NCG production region comprising one or more of the gas production points;

40. The process of claim 39, wherein the injection well and production well each comprise:

a heel segment that is proximal to a vertical segment of the well that connects the horizontal segment of the well to the surface completion; and,

a toe segment that is spaced apart from the heel by the horizontal segment of the well.

41. The process of claim 40, wherein the production well comprises one or more of the gas production points in the NCG production region of the production well, and the NCG production region of the production well is proximal to the heel segment of the production well.

42. The process of claim 41, wherein an intermediate casing point of the injector well is landed at a shallow angle so as to increase the vertical spacing between the heel of the injector well and the heel of the producer well.

43. The process of claim 40, wherein the production well comprises one or more of the gas production points in the NCG production region of the production well, and the NCG production region of the production well is proximal to the toe segment of the production well.

44. The process of claim 40, wherein the production well comprises one or more of the gas production points in the NCG production region of the production well, and the NCG production region of the production well is intermediately spaced apart from the heel segment of the production well and the toe segment of the production well.

45. The process of claim 40, wherein the injection well has a sinusoidal trajectory in longitudinal cross section, with high points at the heel of the injection well and between points of NCG egress from an injector tubing into an annulus between the injector tubing and an injector casing.

46. The process of any one of claims 1 to 45, further comprising:

providing a vent well in the reservoir; and,

producing NCGs from the vent well so as to amplify the delivery of the DSL to the oil interface by way of the LSAG flow.

Figure 1

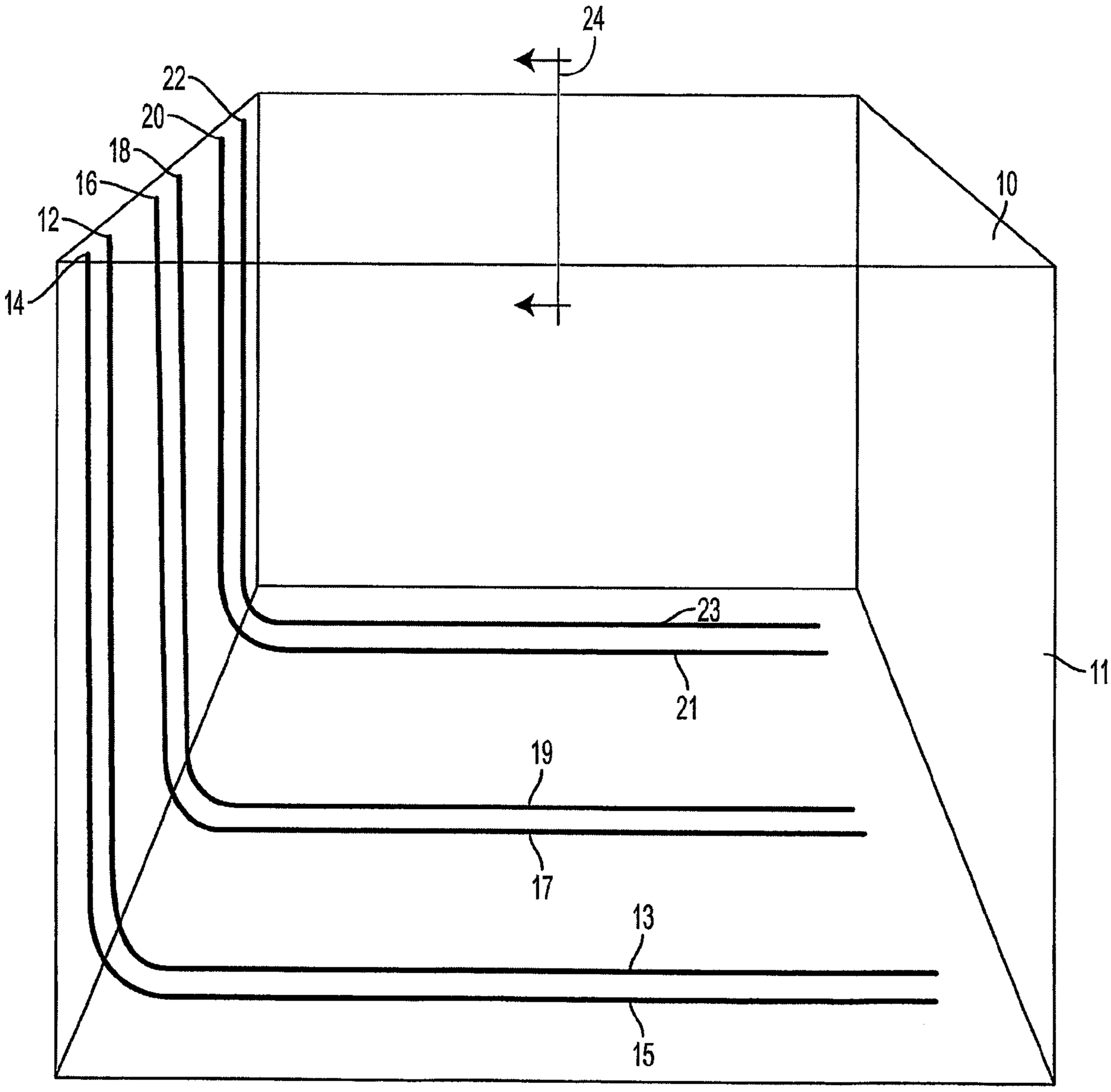


Figure 2

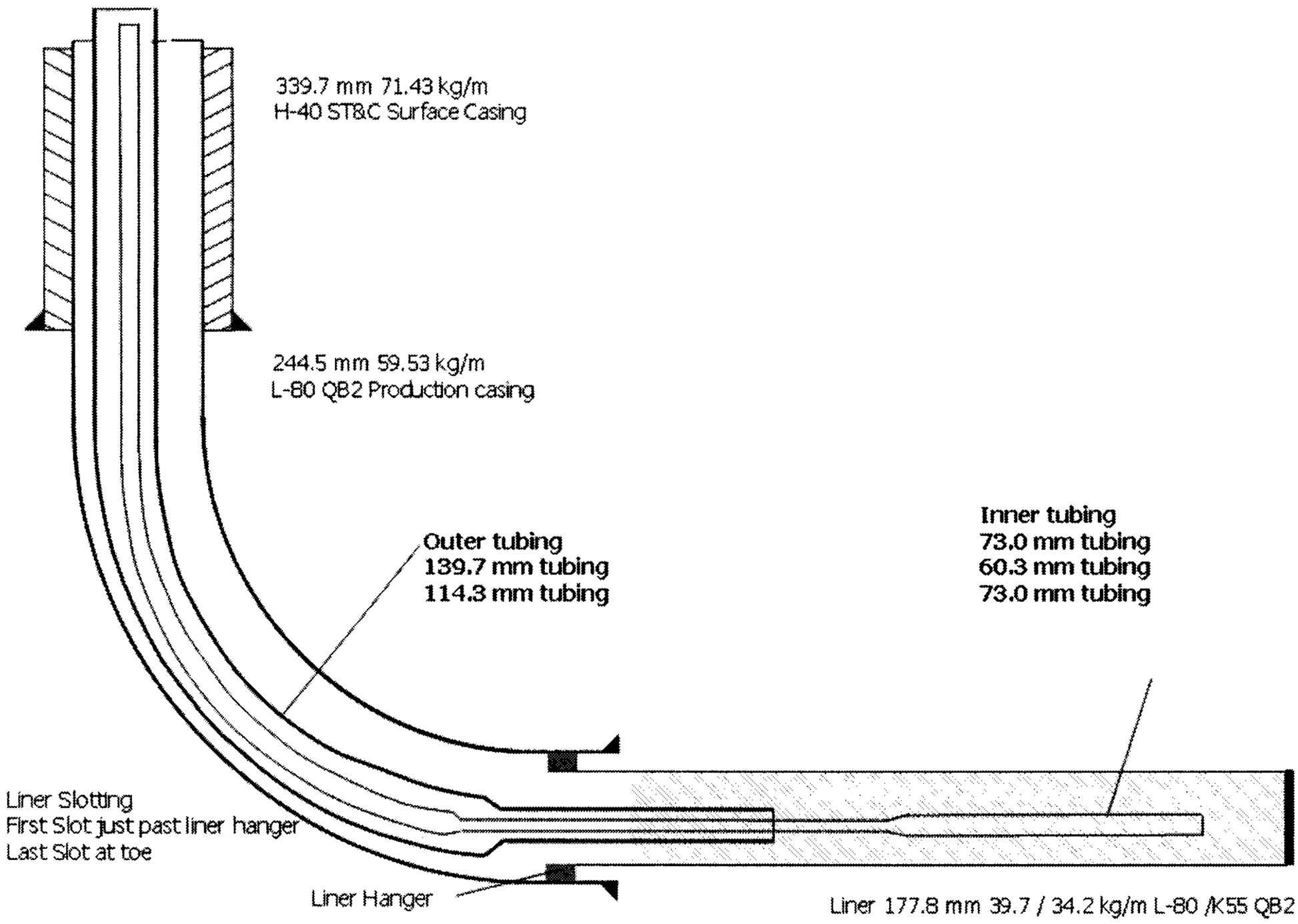

339.7 mm 71.43 kg/m
H-40 ST&C Surface Casing
244.5 mm 59.53 kg/m
L-80 QB2 Production casing
Outer tubing
139.7 mm tubing
114.3 mm tubing
Inner tubing
73.0 mm tubing
60.3 mm tubing
73.0 mm tubing
Liner Slotting
First Slot just past liner hanger
Last Slot at toe
Liner Hanger
Liner 177.8 mm 39.7 / 34.2 kg/m L-80 /K55 QB2

Figure 3

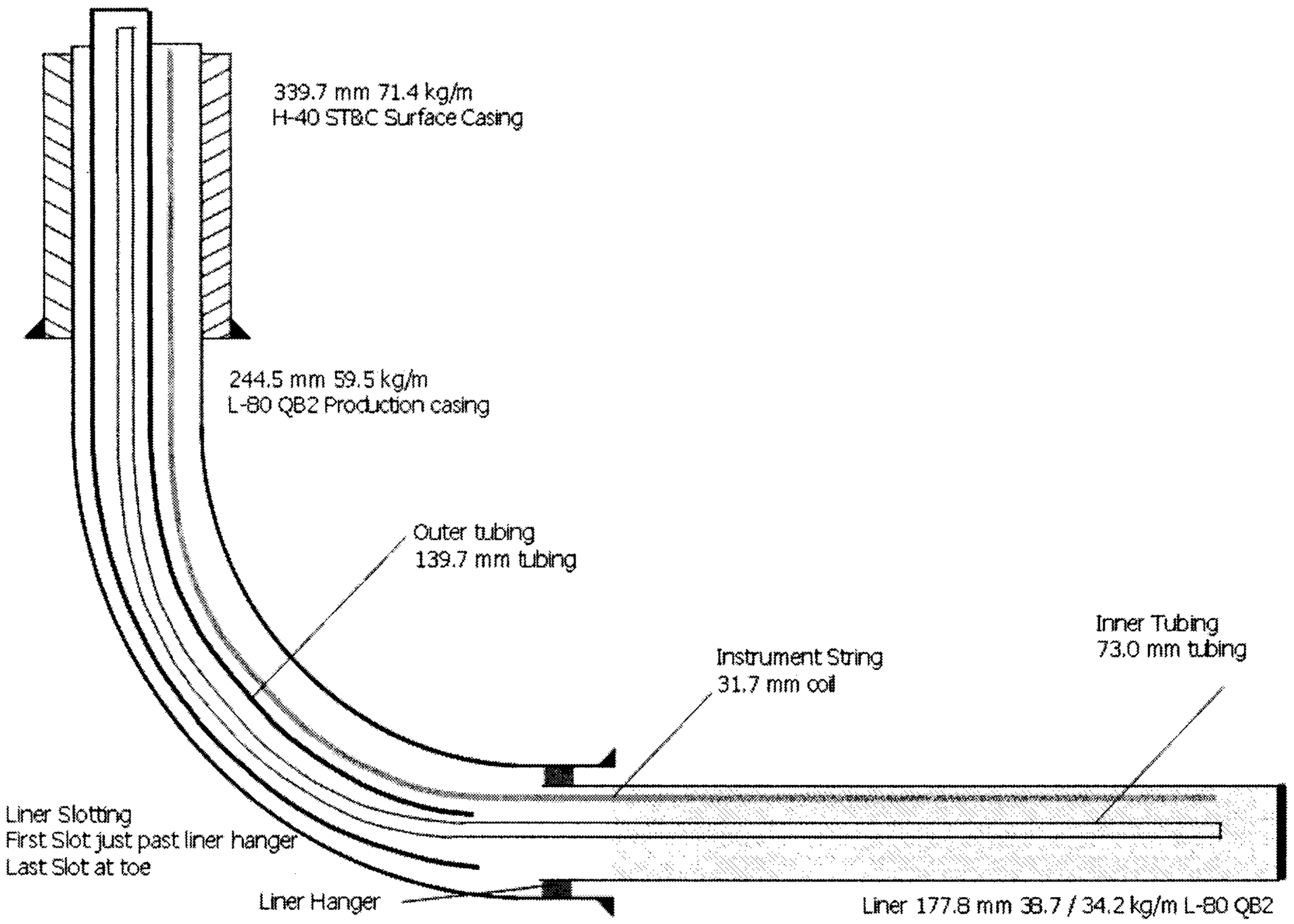

339.7 mm 71.4 kg/m
H-40 ST&C Surface Casing
244.5 mm 59.5 kg/m
L-80 QB2 Production casing
Outer tubing
139.7 mm tubing
Instrument String
31.7 mm coil
Inner Tubing
73.0 mm tubing
Liner Slotting
First Slot just past liner hanger
Last Slot at toe
Liner Hanger
Liner 177.8 mm 38.7 / 34.2 kg/m L-80 QB2

Figure 4

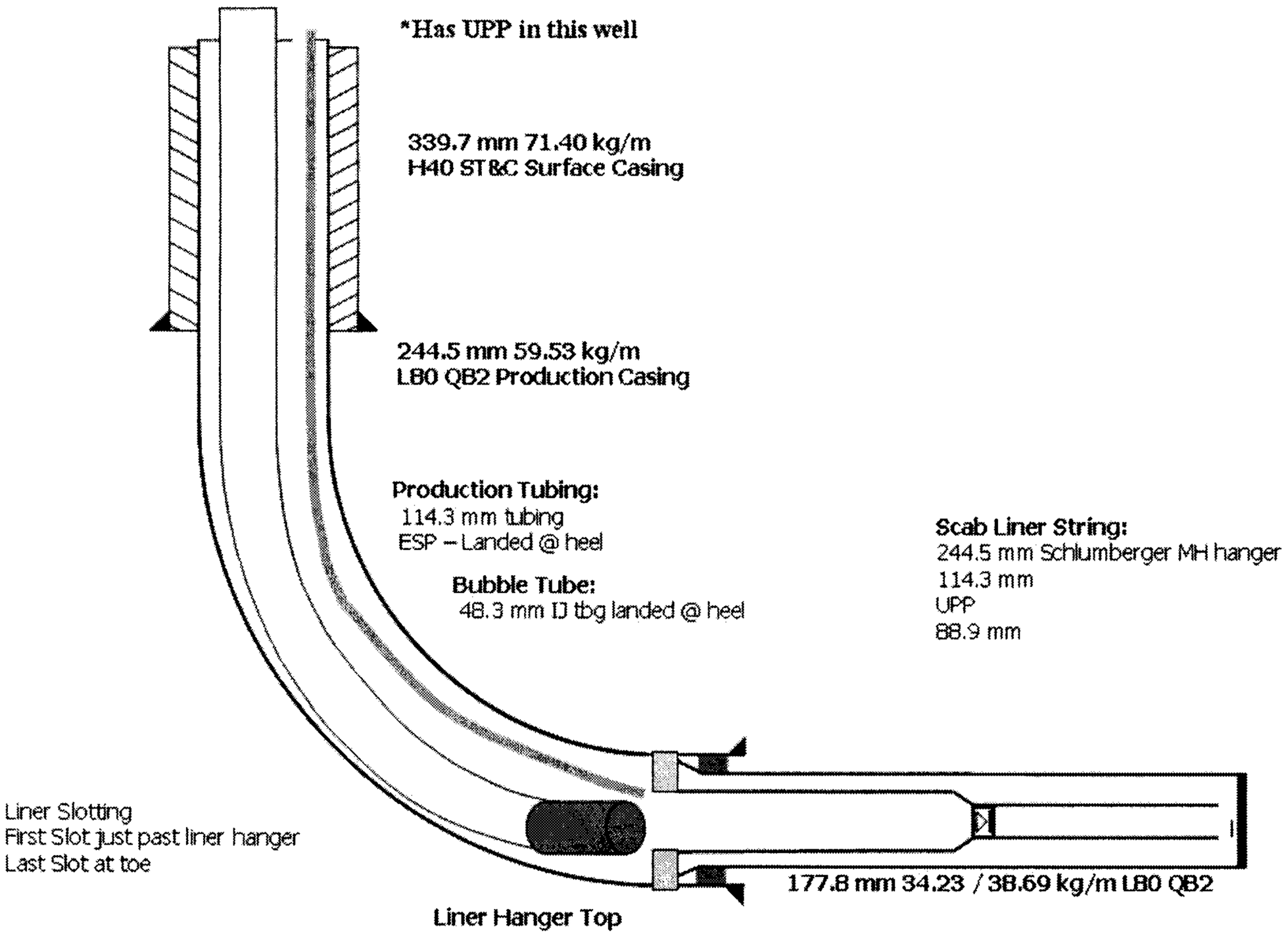

*Has UPP in this well
339.7 mm 71.40 kg/m
H40 ST&C Surface Casing
244.5 mm 59.53 kg/m
L80 QB2 Production Casing
Production Tubing:
114.3 mm tubing
ESP – Landed @ heel
Bubble Tube:
48.3 mm IJ tbg landed @ heel
Scab Liner String:
244.5 mm Schlumberger MH hanger
114.3 mm
UPP
88.9 mm
Liner Slotting
First Slot just past liner hanger
Last Slot at toe
177.8 mm 34.23 / 38.69 kg/m L80 QB2
Liner Hanger Top

Figure 5

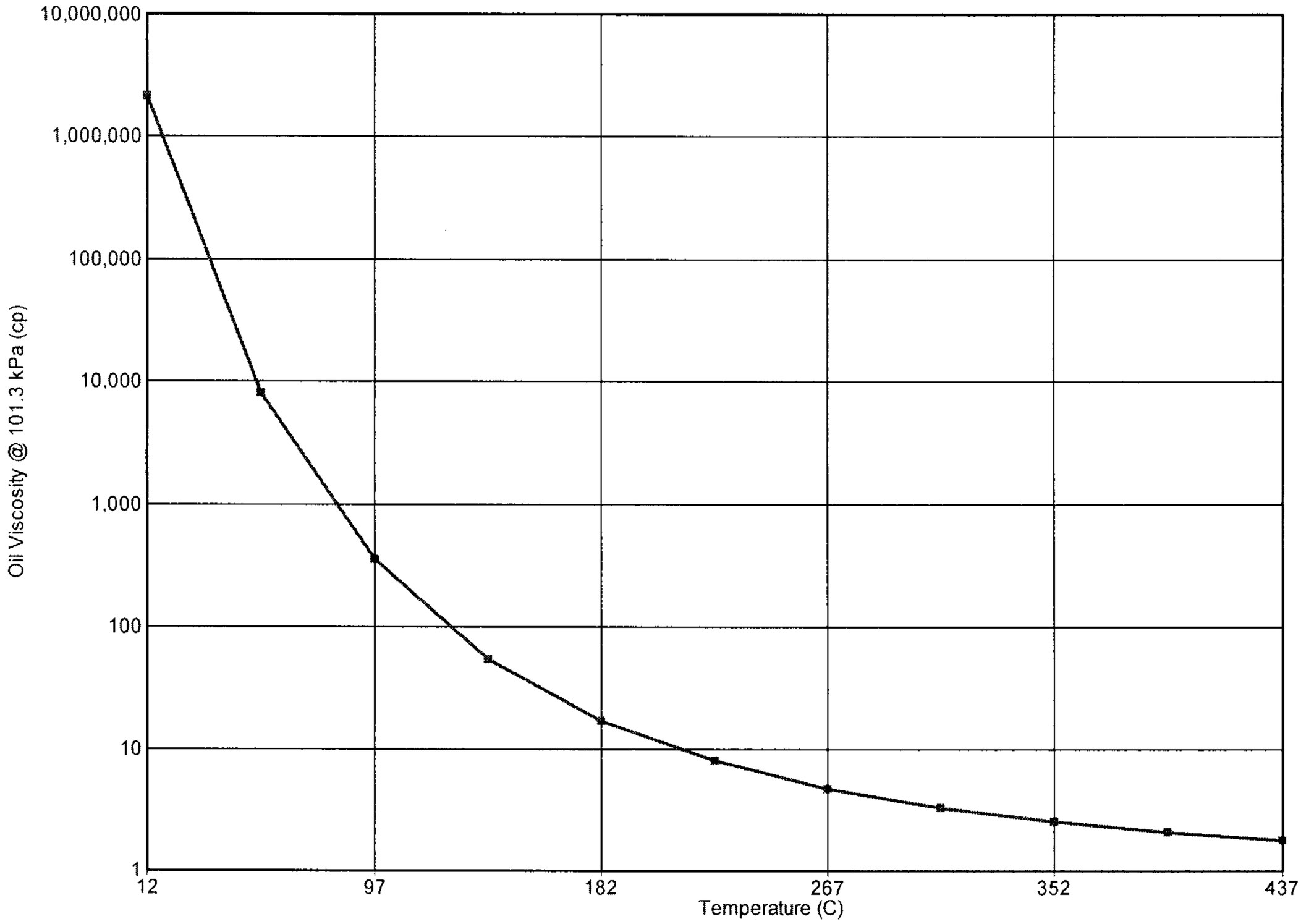

10,000,000
1,000,000
100,000
10,000
1,000
100
10
1
Oil Viscosity @ 101.3 kPa (cp)
12
97
182
267
352
437
Temperature (C)

Figure 6

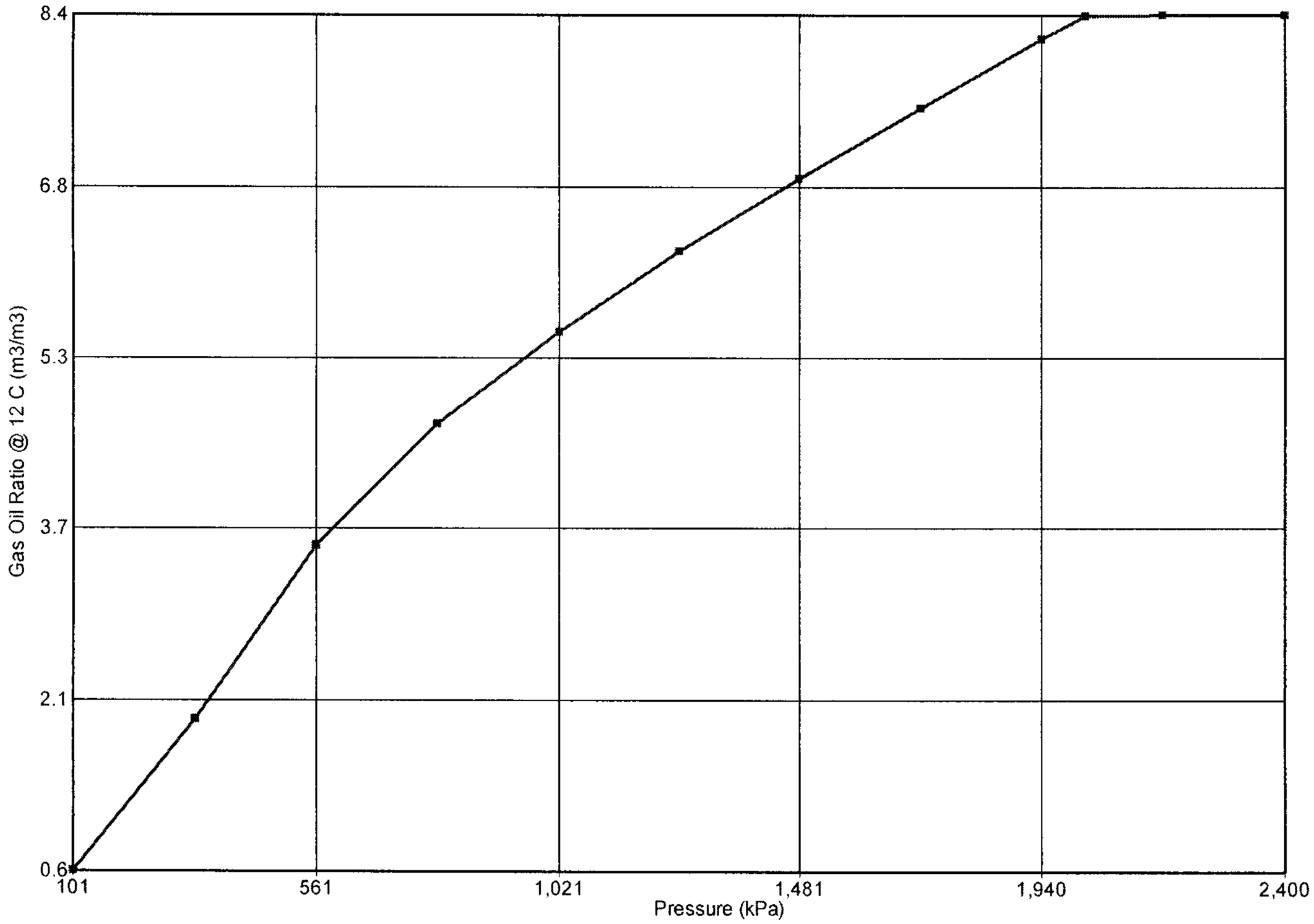

8.4
6.8
5.3
3.7
2.1
0.6
Gas Oil Ratio @ 12 C (m3/m3)
101
561
1,021
1,481
1,940
2,400
Pressure (kPa)

Figure 7

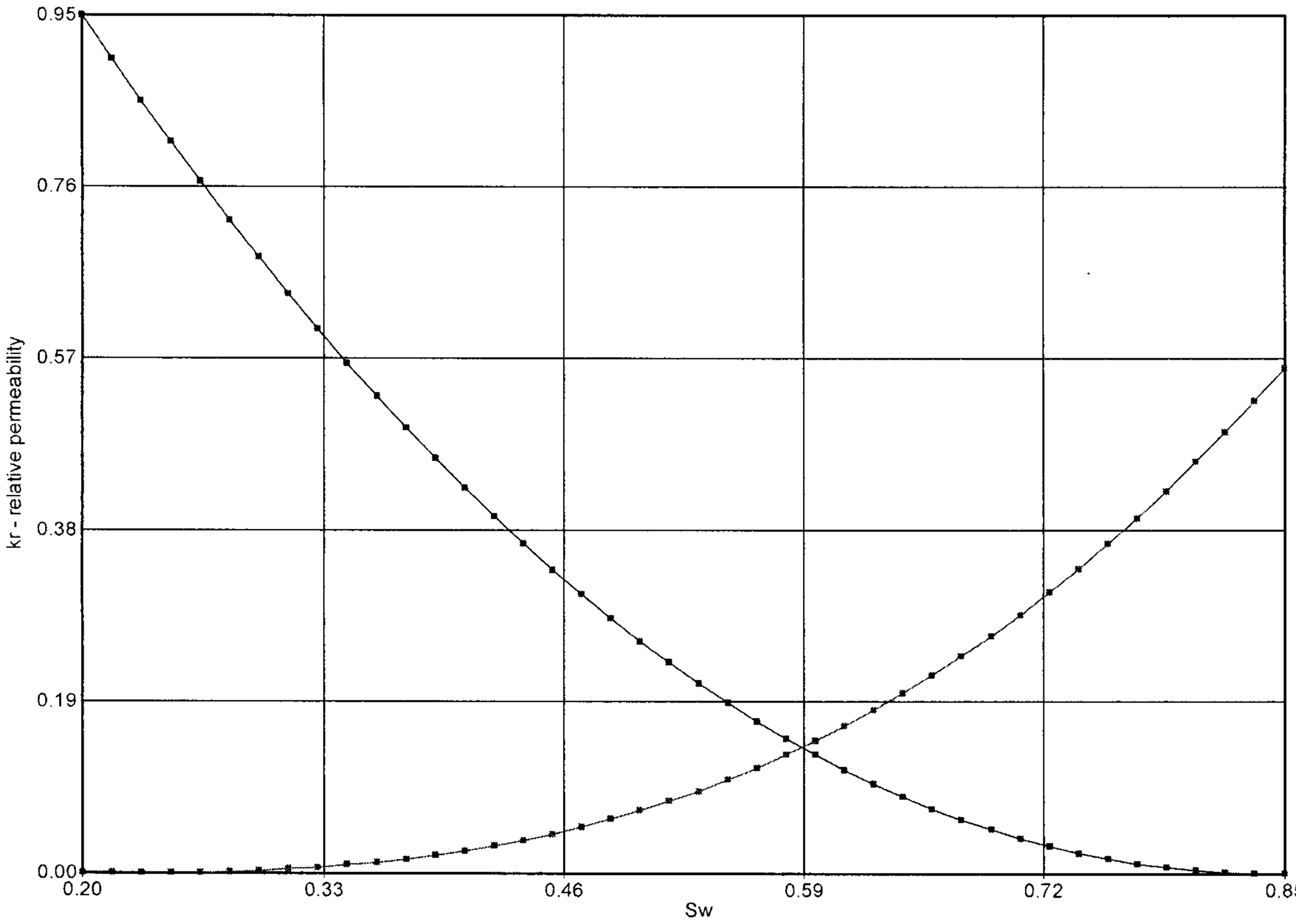

0.95
0.76
0.57
0.38
0.19
0.00
kr - relative permeability
0.20
0.33
0.46
0.59
0.72
0.85
Sw

Figure 8

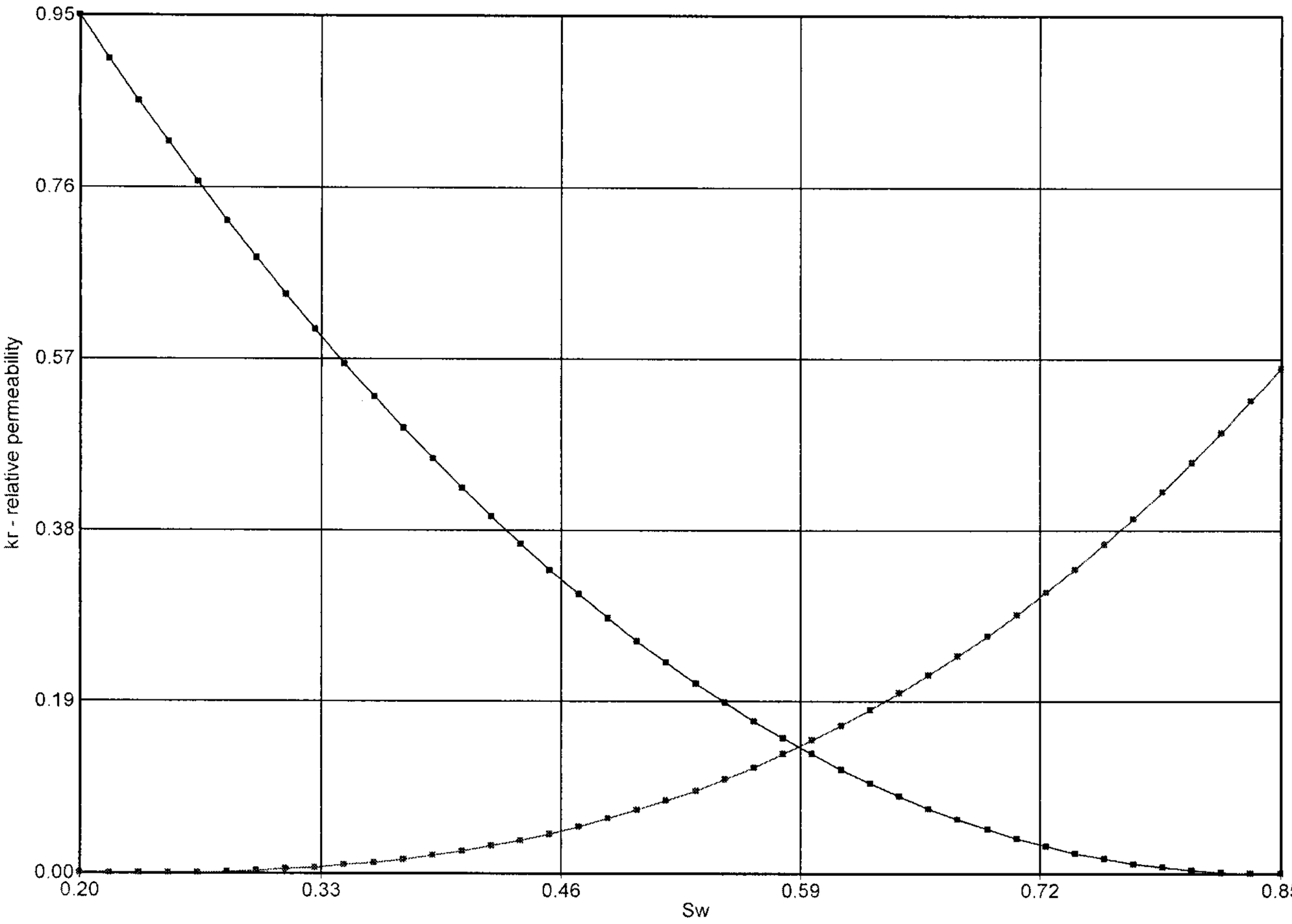

0.95
0.76
0.57
0.38
0.19
0.00
kr - relative permeability
0.20
0.33
0.46
0.59
0.72
0.85
Sw

Figure 9

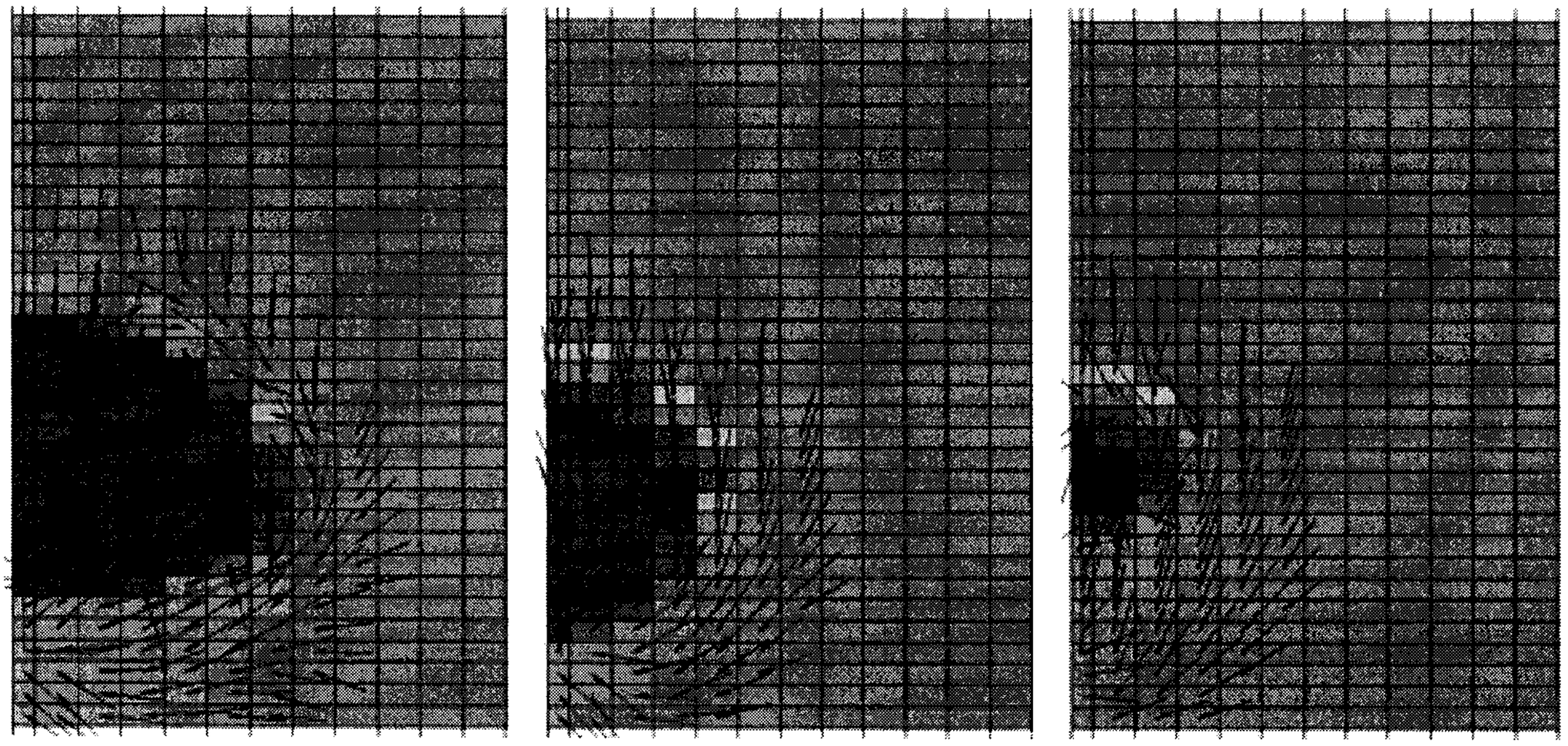


Figure 10

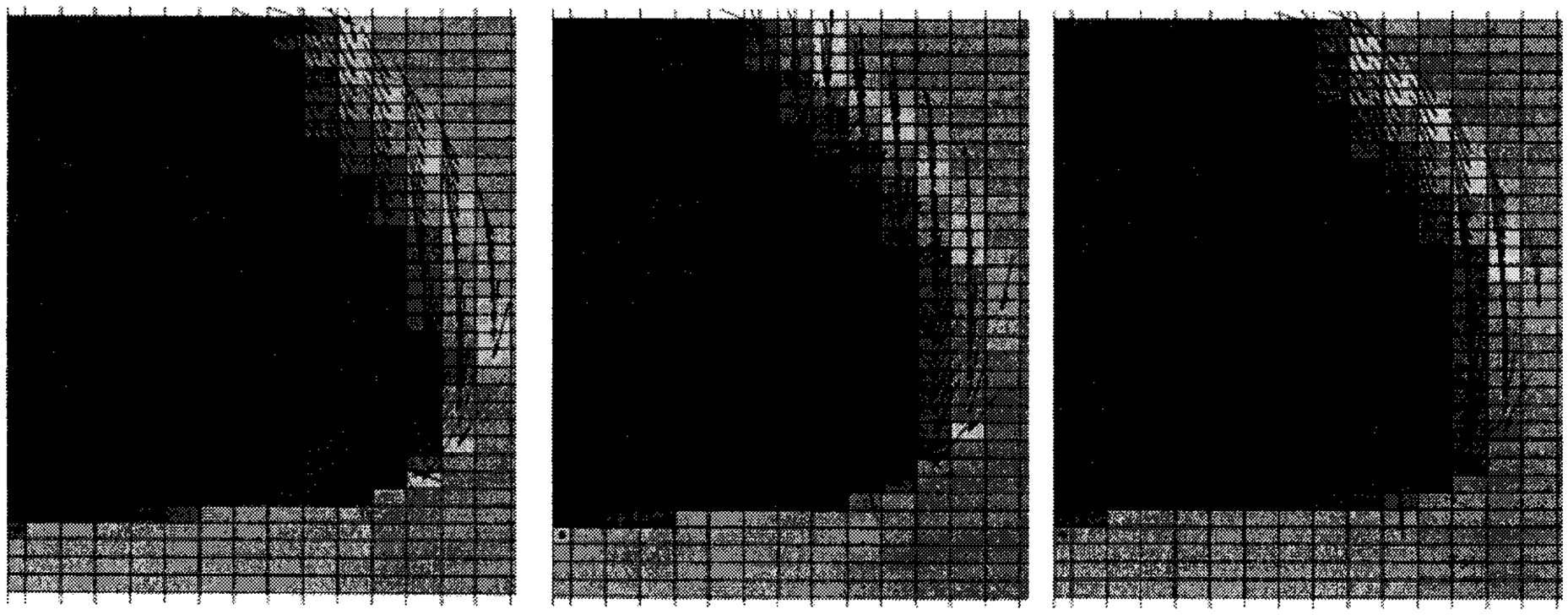
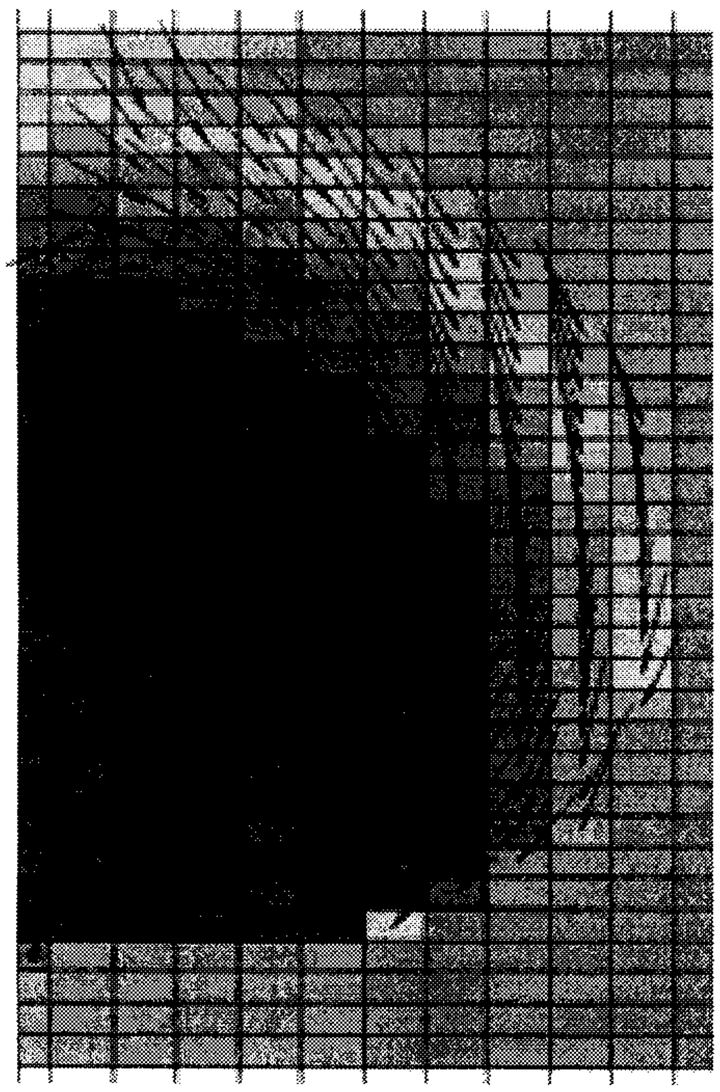


Figure 11



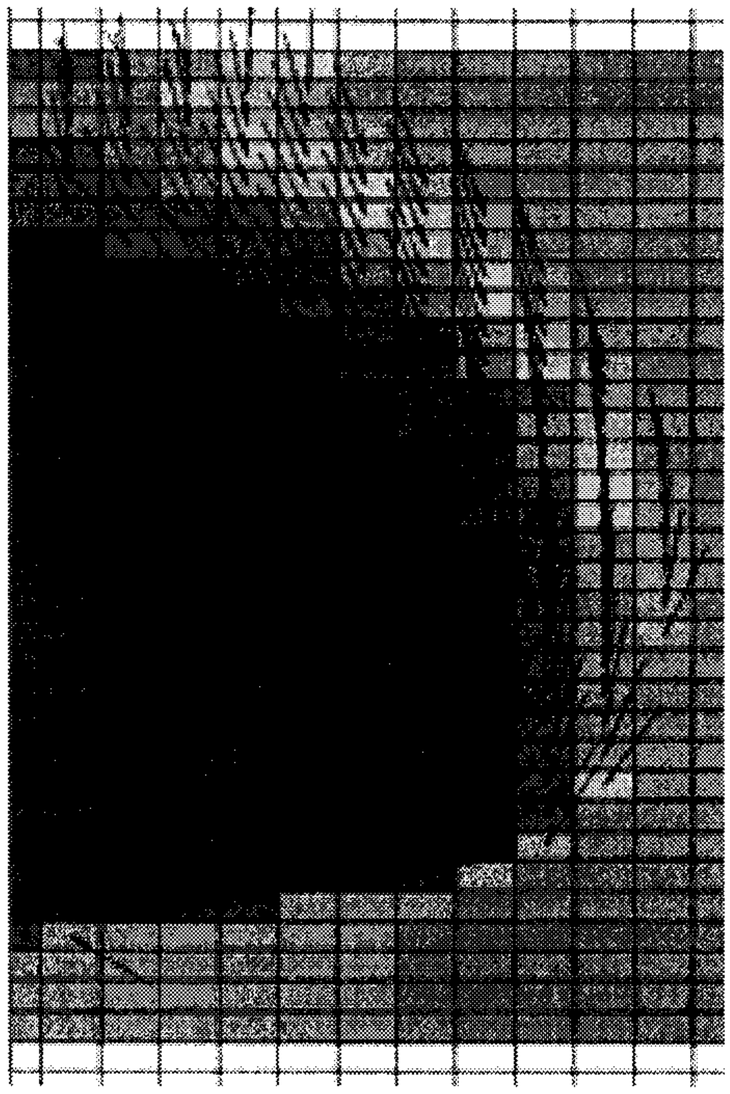


Figure 12

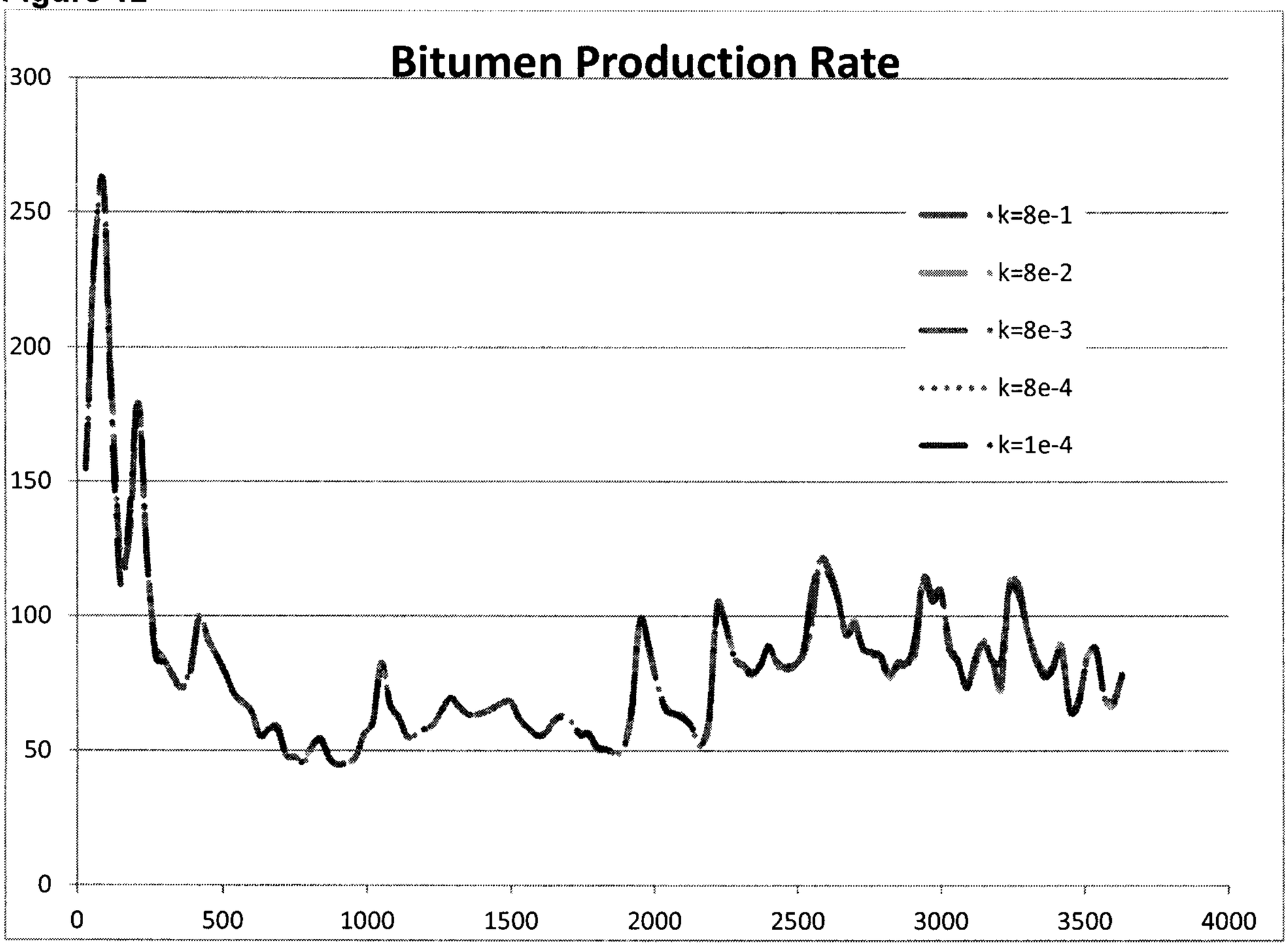

Bitumen Production Rate
300
250
200
150
100
50
0
0
500
1000
1500
2000
2500
3000
3500
4000
k=8e-1
k=8e-2
k=8e-3
k=8e-4
k=1e-4

Figure 13

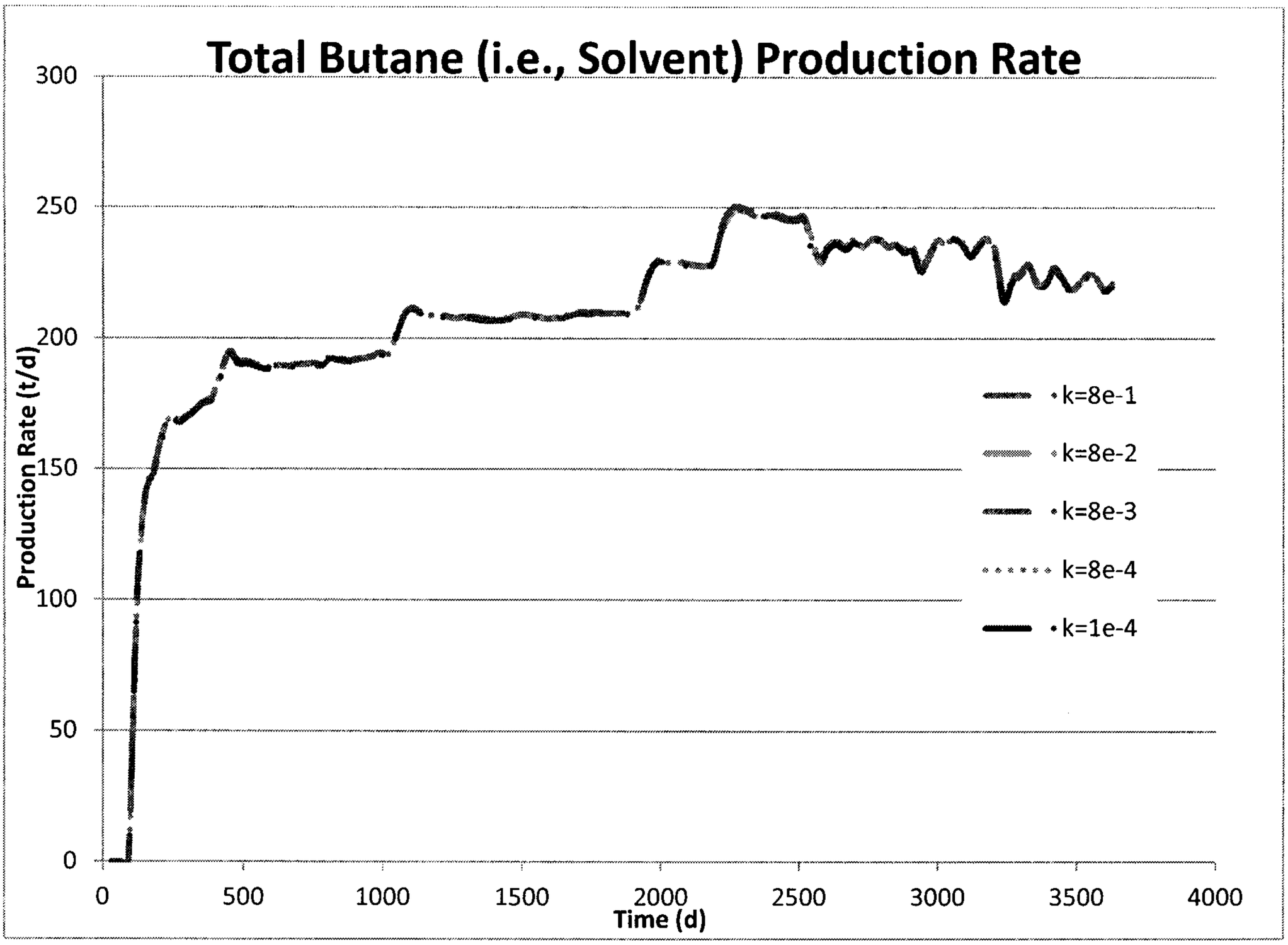

Total Butane (i.e., Solvent) Production Rate
Production Rate (t/d)
300
250
200
150
100
50
0
0
500
1000
1500
2000
2500
3000
3500
4000
Time (d)
k=8e-1
k=8e-2
k=8e-3
k=8e-4
k=1e-4

Figure 14

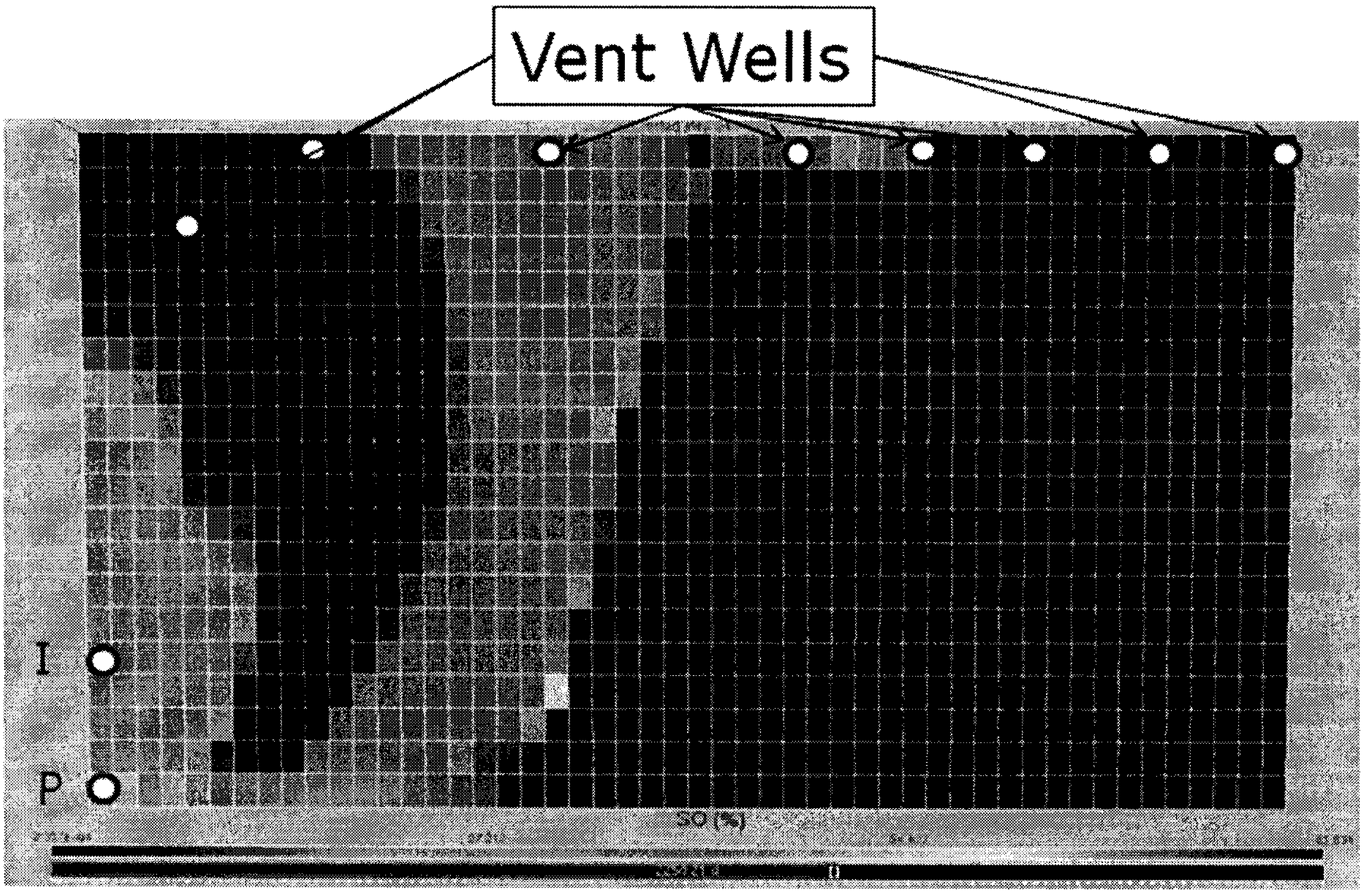


Figure 15

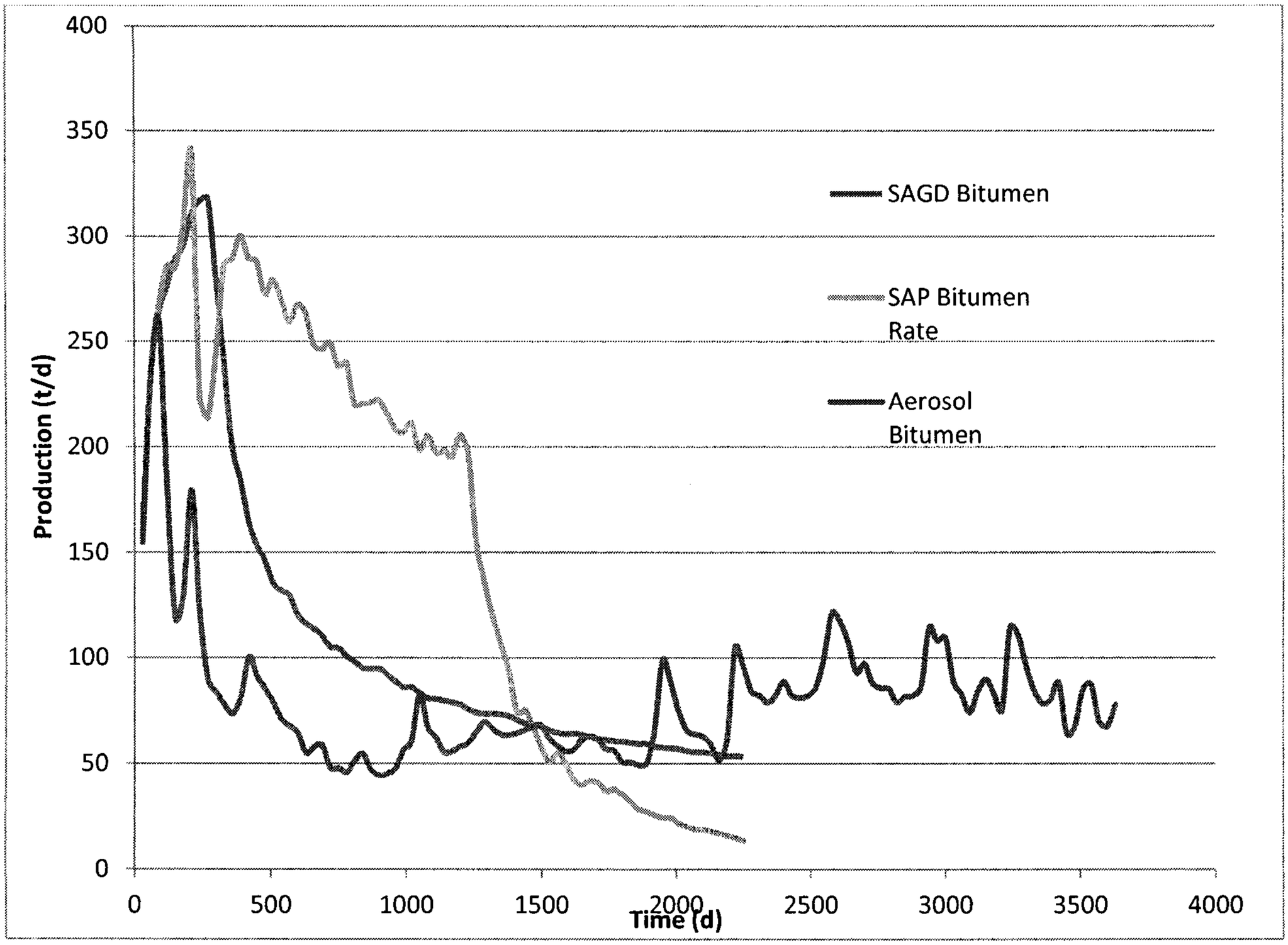

400
350
300
250
200
150
100
50
0
Production (t/d)
0
500
1000
1500
2000
2500
3000
3500
4000
Time (d)
SAGD Bitumen
SAP Bitumen Rate
Aerosol Bitumen

Figure 16

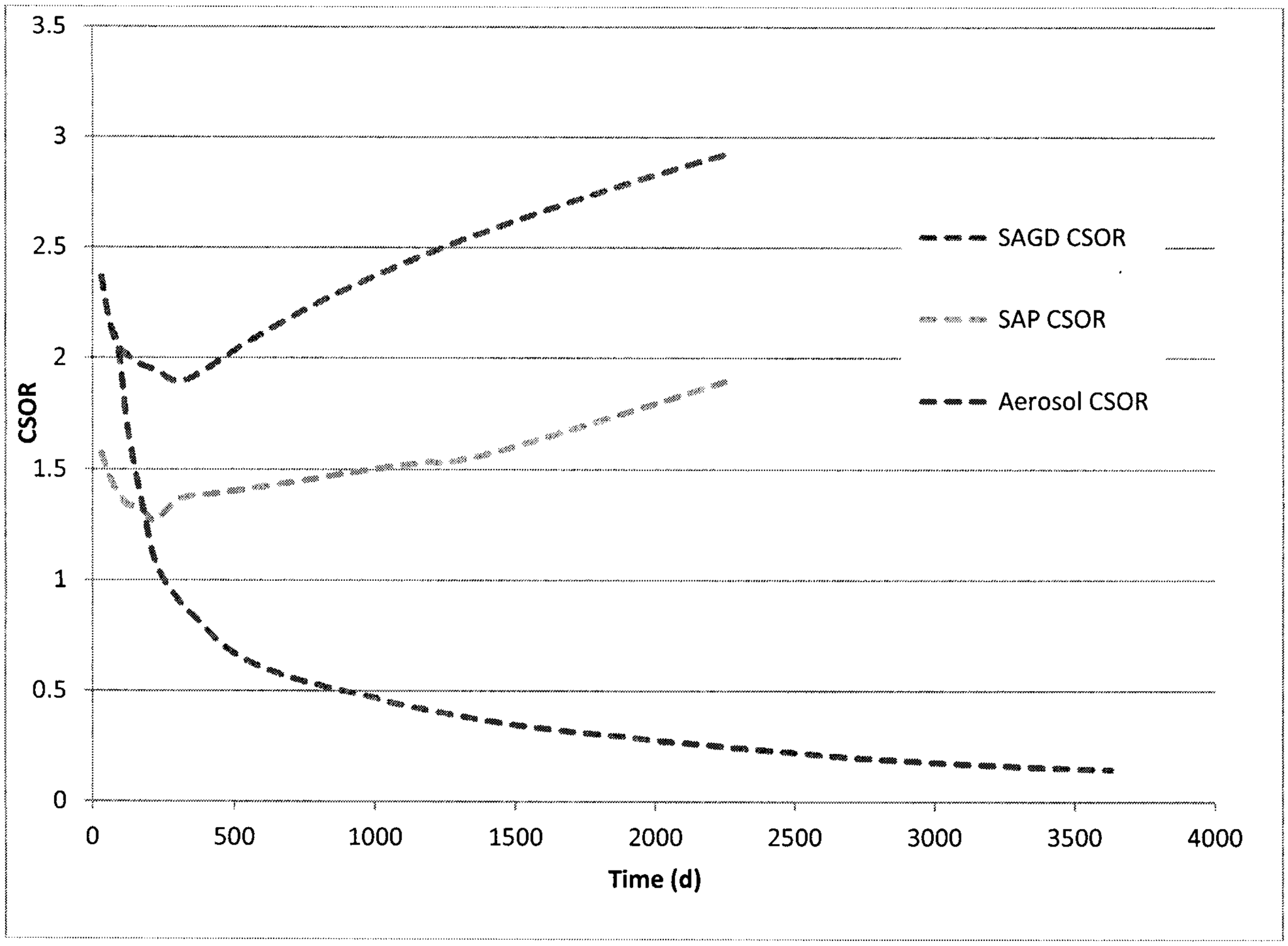
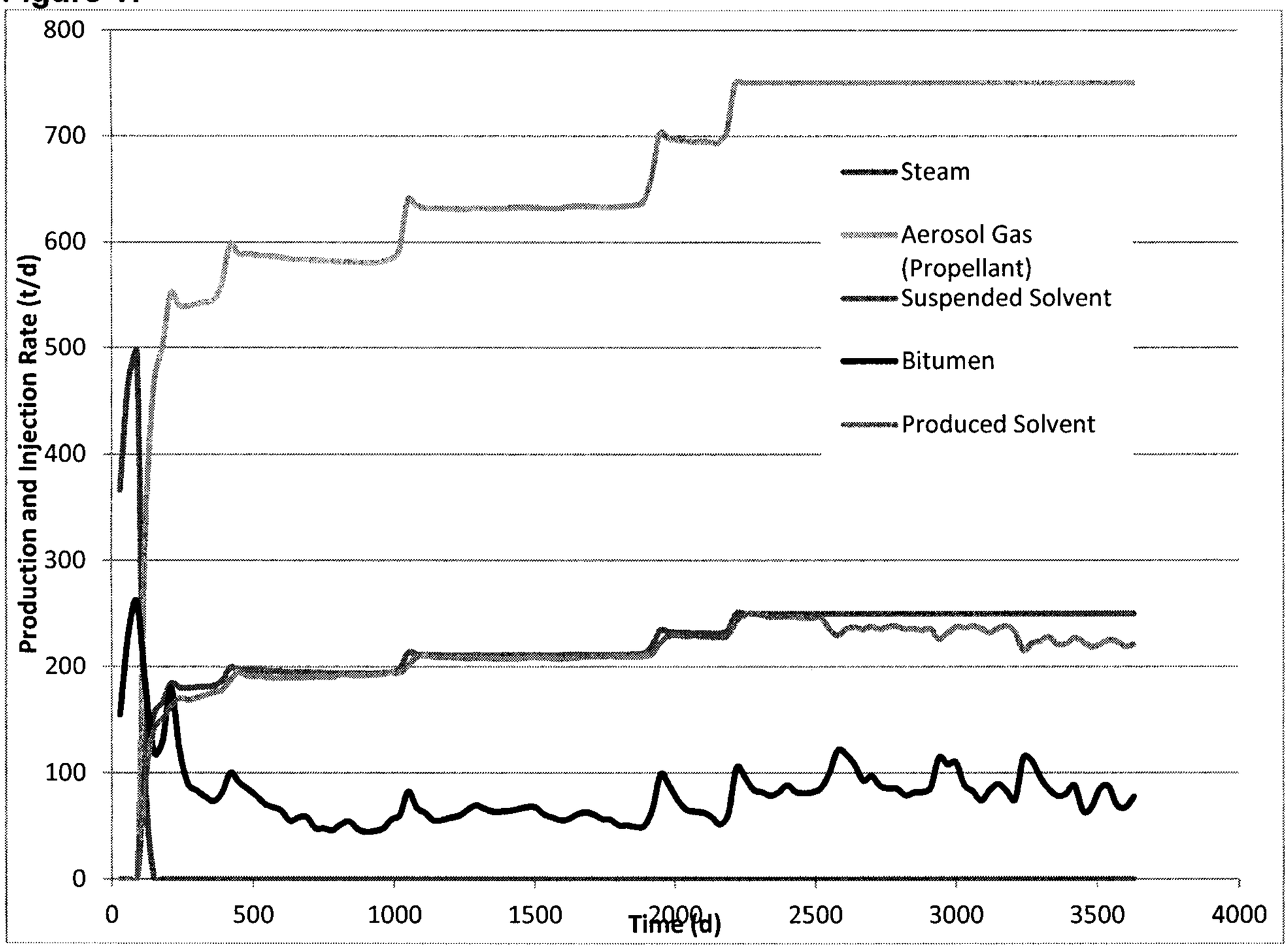
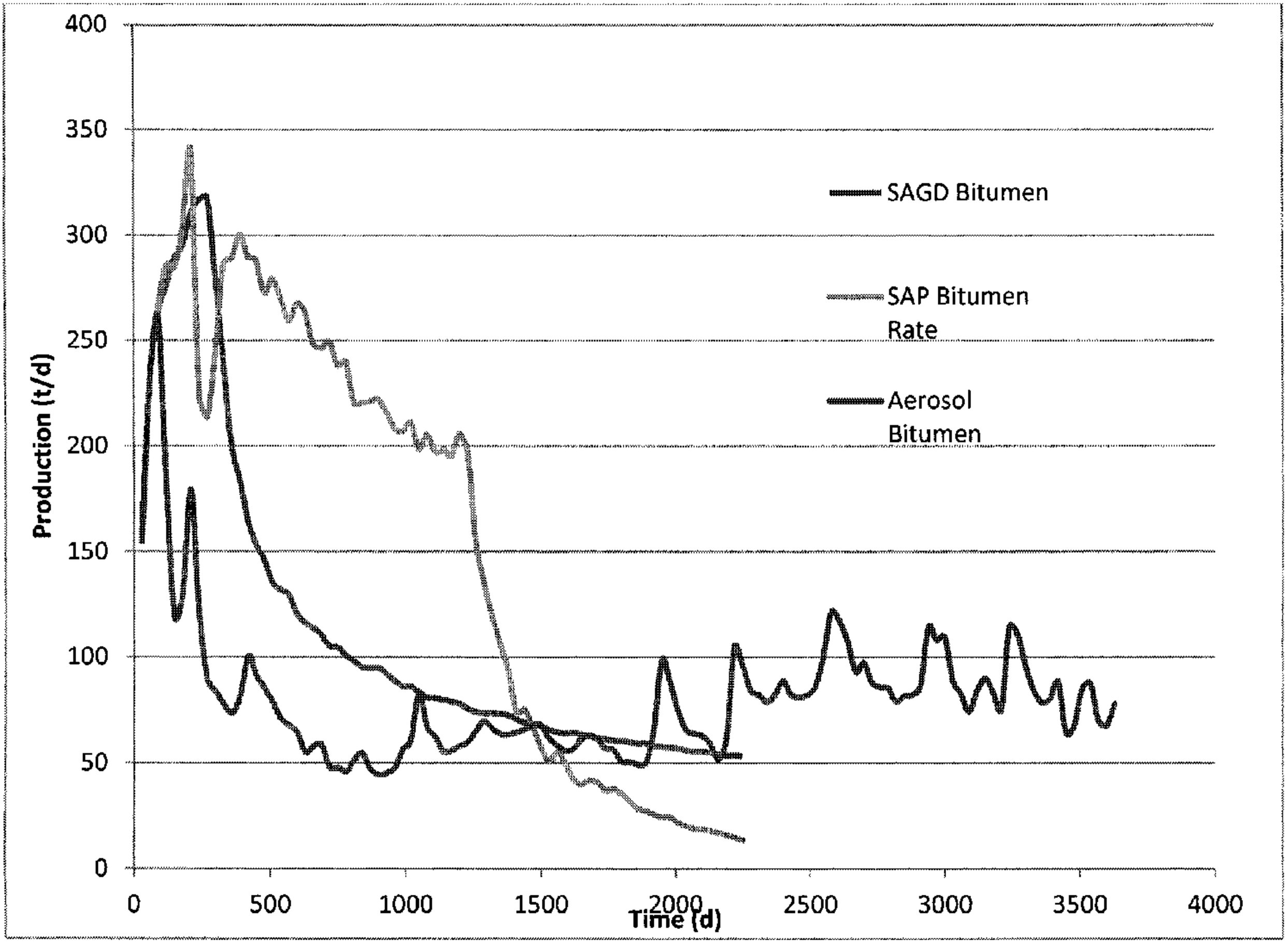

3.5
3
2.5
2
1.5
1
0.5
0
CSOR
0
500
1000
1500
2000
2500
3000
3500
4000
Time (d)
SAGD CSOR
SAP CSOR
Aerosol CSOR

Figure 17


800
700
600
500
400
300
200
100
0
Production and Injection Rate (t/d)
0
500
1000
1500
2000
2500
3000
3500
4000
Time (d)
Steam
Aerosol Gas (Propellant)
Suspended Solvent
Bitumen
Produced Solvent


400
350
300
250
200
150
100
50
0
Production (t/d)
0
500
1000
1500
2000
2500
3000
3500
4000
Time (d)
SAGD Bitumen
SAP Bitumen Rate
Aerosol Bitumen