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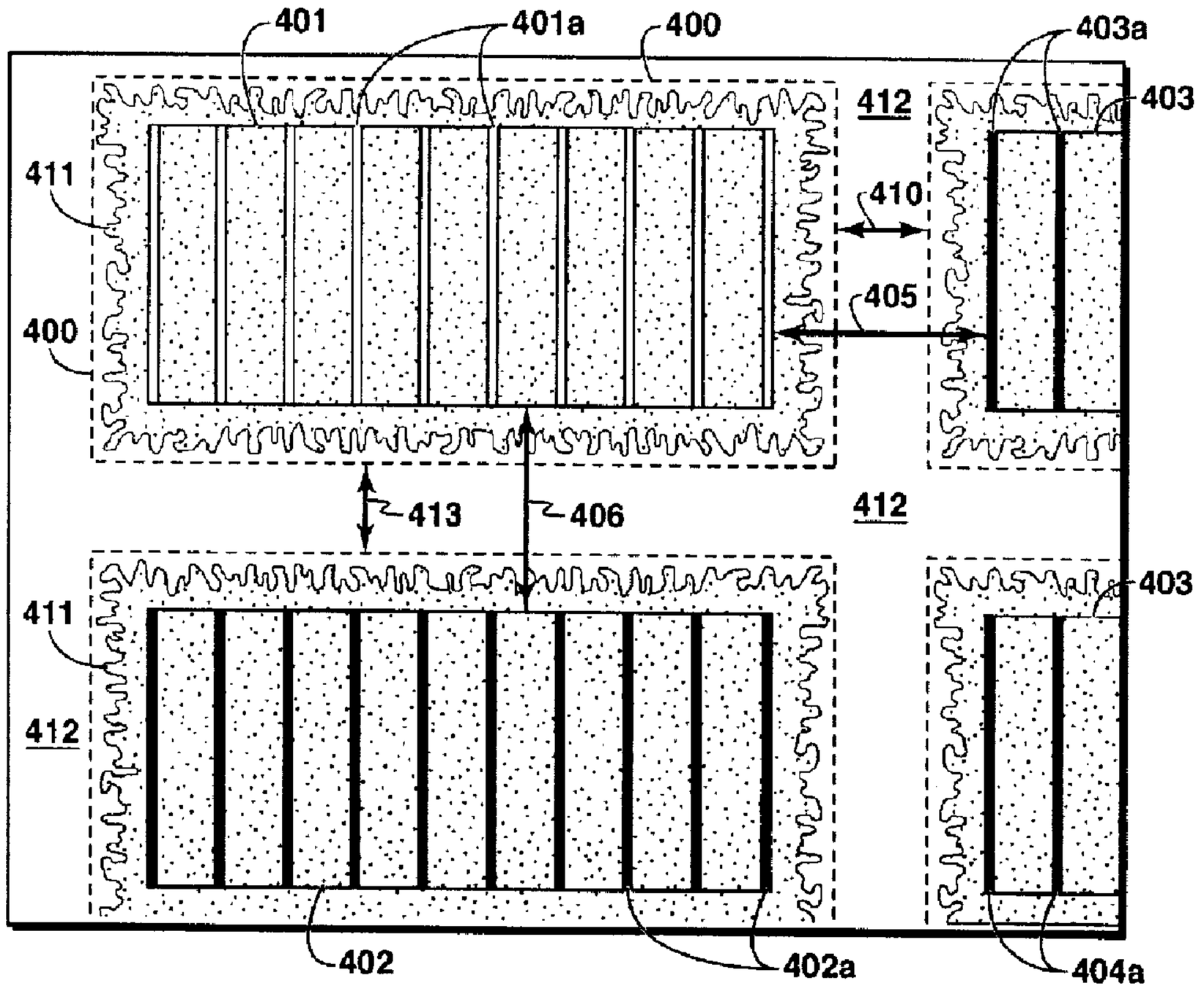
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(54) Titre : EXPLOITATION DE PUITS EN GROUPES DANS UN CONTEXTE DE PROCEDES D'EXTRACTION RECOURANT PRINCIPALEMENT A L'INJECTION DE SOLVANTS

(54) Title: OPERATING WELLS IN GROUPS IN SOLVENT-DOMINATED RECOVERY PROCESSES



(57) Abrégé/Abstract:
To recover oil, including viscous oil, from an underground reservoir, a cyclic solvent-dominated recovery process may be used. A viscosity reducing solvent is injected, and oil and solvent are produced. Unlike steam-dominated recovery processes, solvent-dominated recovery processes cause viscous fingering which should be controlled. To control viscous fingering, operational synchronization is used within groups and not between adjacent groups.

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ABSTRACT

To recover oil, including viscous oil, from an underground reservoir, a cyclic solvent-dominated recovery process may be used. A viscosity reducing solvent is injected, and oil and solvent are produced. Unlike steam-dominated recovery processes, solvent-dominated recovery processes cause viscous fingering which should be controlled. To control viscous fingering, operational synchronization is used within groups and not between adjacent groups.

OPERATING WELLS IN GROUPS IN SOLVENT-DOMINATED RECOVERY PROCESSES

FIELD OF THE INVENTION

[0001] The present invention relates generally to well operations in solvent-dominated *in situ* hydrocarbon recovery processes.

BACKGROUND OF THE INVENTION

[0002] Solvent-dominated *in situ* oil recovery processes are those in which chemical solvents are used to reduce the viscosity of the *in situ* oil. A minority of commercial viscous oil recovery processes use solvents to reduce viscosity. Most commercial recovery schemes rely on thermal methods such as Cyclic Steam Stimulation (CSS, see, for example, U.S. Patent No. 4,280,559) and Steam-Assisted Gravity Drainage (SAGD, see, for example U.S. Patent No. 4,344,485) to reduce the viscosity of the *in situ* oil. As thermal recovery technology has matured, practioners have added chemical solvents, typically hydrocarbons, to the injected steam in order to obtain additional viscosity reduction. Examples include Liquid Addition to Steam For Enhancing Recovery (LASER, see, for example, U,S, Patent No. 6,708,759) and Steam And Vapor Extraction processes (SAVEX, see, for example, U.S. Patent No. 6,662,872). These processes use chemical solvents as an additive within an injection stream that is steam-dominated. Solvent-dominated recovery processes are a possible next step for viscous oil recovery technology. In these envisioned processes, chemical solvent is the principal component within the injected stream. Some non-commercial technology, such as Vapor Extraction (VAPEX, see, for example, R. M. Butler & I. J. Mokrys, J. of Canadian Petroleum Technology, Vol. 30, pp. 97-106) and Cyclic Solvent-Dominated Recovery Process (CSDRP, see, for example, Canadian Patent No. 2,349,234) use injectants that may be 100%, or nearly all, chemical solvent.

[0003] Solvent-dominated processes are different from steam-dominated processes in several respects. In steam-dominated processes, viscous fingering does not typically occur. Heat transfer dominates over mass transfer, blunting viscous finger formation. Other differences include the phase of the injectant – always gaseous for steam-dominated processes and gaseous or liquid for solvent-dominated processes. Additionally, solvent is, by definition, at least partially miscible with oil, and steam is not. In their totality, these differences lead to fundamentally different challenges in well spacing, operation, and

orientation, primarily due to a desire to control viscous fingering in solvent-dominated processes.

[0004] At the present time, solvent-dominated recovery processes (SDRPs) are rarely used to produce highly viscous oil. Highly viscous oils are produced primarily using thermal methods in which heat, typically in the form of steam, is added to the reservoir. Cyclic solvent-dominated recovery processes (CSDRPs) are a subset of SDRPs. A CSDRP is typically, but not necessarily, a non-thermal recovery method that uses a solvent to mobilize viscous oil by cycles of injection and production. Solvent-dominated means that the injectant comprises greater than 50% by mass of solvent or that greater than 50% of the produced oil's viscosity reduction is obtained by chemical solvation rather than by thermal means. One possible laboratory method for roughly comparing the relative contribution of heat and dilution to the viscosity reduction obtained in a proposed oil recovery process is to compare the viscosity obtained by diluting an oil sample with a solvent to the viscosity reduction obtained by heating the sample.

[0005] In a CSDRP, a viscosity-reducing solvent is injected through a well into a subterranean viscous-oil reservoir, causing the pressure to increase. Next, the pressure is lowered and reduced-viscosity oil is produced to the surface through the same well through which the solvent was injected. Multiple cycles of injection and production are used. In some instances, a well may not undergo cycles of injection and production, but only cycles of injection or only cycles of production.

[0006] CSDRPs may be particularly attractive for thinner or lower-oil-saturation reservoirs. In such reservoirs, thermal methods utilizing heat to reduce viscous oil viscosity may be inefficient due to excessive heat loss to the overburden and/or underburden and/or reservoir with low oil content.

[0007] References describing specific CSDRPs include: Canadian Patent No. 2,349,234 (Lim et al.); G. B. Lim et al., "Three-dimensional Scaled Physical Modeling of Solvent Vapour Extraction of Cold Lake Bitumen", The Journal of Canadian Petroleum Technology, 35(4), pp. 32-40, April 1996; G. B. Lim et al., "Cyclic Stimulation of Cold Lake Oil Sand with Supercritical Ethane", SPE Paper 30298, 1995; US Patent No. 3,954,141 (Allen et al.); and M. Feali et al., "Feasibility Study of the Cyclic VAPEX Process for Low Permeable Carbonate Systems", International Petroleum Technology Conference Paper 12833, 2008.

[0008] The family of processes within the Lim et al. references describes embodiments of a particular SDRP that is also a cyclic solvent-dominated recovery process (CSDRP). These processes relate to the recovery of heavy oil and bitumen from subterranean reservoirs using cyclic injection of a solvent in the liquid state which vaporizes upon production. The family of processes within the Lim et al. references may be referred to as CSP™ processes.

[0009] Other descriptions of solvent-based processes are also disclosed in the literature.

[0010] *Allen et al.* (U.S. Patent No. 3,954,141) disclose a multiple solvent heavy oil recovery method. They write (col.3, lines 49-51), "It is desirable that the solvent mixture enter the formation as a liquid." They go on to write (col. 4, lines 11-13), "As the solvent mixture is injected into the well it spreads radially outward from the injection well and dissolves into viscous petroleum." This description does not consider viscous fingering. Consequently, *Allen et al.* do not discuss ways to minimize the adverse effects of viscous fingering.

[0011] *Upreti et. al.* (*Energy* & Fuels 2007, 21, 1562-1574) wrote a review article discussing the current state of understanding of Vapor Extraction (VAPEX), by far the most-studied solvent-dominated viscous oil recovery process. In VAPEX (p. 1564), "A vaporized solvent is injected into the injection well at pressures slightly less than or equal to the saturation vapor pressure." Injection at "pressures slightly less than or equal to the saturation vapor pressure," avoids the high pressure and consequent steep pressure gradients that exacerbate viscous fingering. The authors discuss well arrangement briefly (p. 1564), "For many heavy oil and bitumen reservoirs, the use of horizontal wells over short distances is a preferred choice so as to avoid high injection pressures and channeling of the solvents." (see also *Turta et al.*, J. Canadian Petroleum Technology, vol. 43, pp. 29-37, 2004). Upreti concludes (pg. 1573) that more research is needed for VAPEX, especially in the areas of, "... solvent mixing and absorption and heavy oil and bitumen, well configurations, ...".

[0012] Additional patents that disclose methods for the recovery of viscous oil using solvent-dominated recovery processes include:

U.S. Patent No. 6,883,607	Nenniger et al;
U.S. Patent No. 6,318,464	Mokrys;
U.S. Patent No. 5,899,274	Frauenfeld et al.; and

U.S. Patent No. 4,362,213 Tabor.

[0013] These patents do not detail the arrangement, orientation, and operation of wells to reduce viscous fingering.

[0014] The phenomenon of viscous fingering is discussed in, for example, *Cuthiell et. al. 2003* (J. Canadian Petroleum Technology, vol. 42, pp. 41-49, 2003) and *Cuthiell et. al. 2006* (J. Canadian Petroleum Technology, vol. 45, pp. 29-39, 2006). In particular, *Cuthiell et. al. 2006* describe the importance of viscous fingering for cyclic and non-cyclic solvent-dominated processes. *Cuthiell et al. 2006* disclose (p. 29) that, "miscible fingering is suppressed by transverse dispersion and by gravity," however, *Cuthiell et. al. 2006* does not discuss well orientation and layout.

[0015] Jørgensen (U.S. Patent No. 7,165,616) discloses a "Method of controlling the direction of propagation of injection fractures in permeable formations". *Jørgensen* does not discuss viscous fingering, but is instead concerned with the control of fracturing (col. 1, lines 41-43), "... the present invention aims to enable control of the propagation of such fracture in such a manner that the fracture has a controlled course...". Therefore, *Jørgensen* does not disclose well arrangements and operations for controlling solvent fingering.

[0016] Therefore, there is a need for an improved well operation for solvent-dominated recovery processes for controlling viscous fingering.

SUMMARY OF THE INVENTION

[0017] In one aspect, the present invention provides a method of recovering hydrocarbons, for example viscous oil, from an underground reservoir using a cyclic solvent-dominated recovery process. A viscosity reducing solvent is injected into a set of wells completed in the reservoir. The solvent is allowed to mix with, and at least partially dissolve into, the oil. The pressure in the reservoir is then reduced to produce oil and solvent. These steps are repeated as required. The well operation is tailored to cyclic solvent-dominated recovery processes for managing viscous fingering and unfavorable producer to injector interactions. Generally, wells are operated as groups, with wells in the same group operating in-synch. Groups of wells may be separated by a buffer zone from other groups of wells if the two groups are operated out-of-synch.

[0018] In a first aspect, the present invention provides a method of operating a cyclic solvent-dominated process for recovering hydrocarbons from an underground reservoir through a set of wells divided into groups of wells, the method comprising:

(a) initiating and subsequently halting injection, into one of the groups of wells, of an amount of a viscosity reducing solvent;

(b) initiating and subsequently halting production, from the one of the groups of wells, of at least a fraction of the solvent and the hydrocarbons from the reservoir, and

(c) cyclically repeating steps (a) and (b) for the groups of wells;

wherein:

each of the groups comprises two or more wells and no well is common between two groups; and

wells of the same group are operated substantially in-synch.

[0019] The following features may be present. The wells of the same group may undergo opposite flow operation of injection or production for less than 10% of fluid flow on a mass basis, or less than 5%, or less than 1%. For at least 80% of fluid flow on a mass basis, a single well of at least one group may undergo injection and production while remaining wells within the at least one group are idle. A single well of at least one of group may undergo injection and production while remaining wells within the at least one group are idle. The wells of the same group may undergo the same flow operation of injection or production for more than 80% of fluid flow on a mass basis, or more 90%, or more than 95%. More than 80% of the wells of the same group may undergo the same flow operation of injection or production for more than 80% of an operational time period. All wells of the same group may undergo the same flow operation of injection or production for more than 80% of an operational time period. Adjacent well groups may be operated substantially out-of-synch. Wells of adjacent well groups may undergo opposite flow operation of injection or production for more than 10% of fluid flow on a mass basis. Wells of adjacent well groups may undergo opposite flow operation of injection or production for more than 25% of fluid flow on a mass basis, or more than 50%, or more than 75%, or more than 90%. Immediately after halting injection of the solvent, at least 25 mass % of the injected solvent may be in a liquid state in the reservoir. At least 25 mass % of the solvent in step (a) may enter the reservoir as a liquid. At least 50 mass % of the solvent in step (a) may enter the reservoir as a liquid. Each well within the set of wells may be oriented within 30° of horizontal within the underground reservoir. Within the underground reservoir, the wells in the set may be arranged within 20° of a common horizontal straight line. The single common straight line may be within 20° of a maximum horizontal stress direction within the reservoir. For at least 25% (or at least 50%)

of the time period between injecting and subsequently halting injection for a group of wells, an adjacent group of wells may have at least one well producing; and for at least 25% (or at least 50%) of the time period between producing and subsequently halting producing for a group of wells, an adjacent group of wells may have at least one well injecting. The well groups may be separated by buffer zones for limiting well-to-well interaction, wherein buffer zones contain no flowing wells. The buffer zones may constitute less than or equal to one third of a sum of an area of the groups, or equal to or less than 10% of a sum of an area of the groups. Two wells may be separated by an infill well used for increasing hydrocarbon production prior to and/or during operation. Two wells may be separated by an infill well for increasing reservoir pressure prior to and/or during operation, for limiting well-to-well interaction. Water may be injected into the infill well. At least certain buffer zones may be geological buffer zones. The geological buffer zones may be channel boundaries. Each group may comprise a single row of wells. The hydrocarbons may be a viscous oil having an *in situ* viscosity of greater than 10 cP at initial reservoir conditions. A common wellbore may be used for both the injection and the production. An idle period may exist subsequent to halting injection and prior to initiating production. The solvent may comprise ethane, propane, butane, pentane, carbon dioxide, or a combination thereof. The solvent may comprise greater than 50 mass % propane.

[0020] Other aspects and features of the present invention will become apparent to those ordinarily skilled in the art upon review of the following description of specific embodiments of the invention in conjunction with the accompanying figures.

BRIEF DESCRIPTION OF THE DRAWINGS

[0021] Embodiments of the present invention will now be described, by way of example only, with reference to the attached Figures, wherein:

Fig. 1a is an illustration of adequate field sweep in an inter-well region;

Fig. 1b is an illustration of poor field sweep in an inter-well region due to disproportionate injection in the heel of one well;

Fig. 1c is an illustration of poor field sweep in an inter-well region due to solvent channeling through a finger that connects two wells;

Fig. 2 is an illustration of an example of in-synch and out-of-synch flow operations for two wells;

Fig. 3 is an illustration of an example of a well arrangement in accordance with a disclosed embodiment;

Fig. 4 is an illustration of a well arrangement and operation in accordance with a disclosed embodiment;

Fig. 5 is an illustration of a well arrangement and operation;

Fig. 6 is another illustration of a well arrangement and operation;

Fig. 7 is still another illustration of a well arrangement and operation;

Fig. 8 is still another illustration of a well arrangement and operation;

Fig. 9a is an illustration of a well orientation with respect to a stress field, in accordance with a disclosed embodiment;

Fig. 9b is an illustration of the stresses on a lateral finger; and

Fig. 10 is still another illustration of a well arrangement and operation in accordance with a disclosed embodiment.

DETAILED DESCRIPTION

[0022] The term “viscous oil” as used herein means a hydrocarbon, or mixture of hydrocarbons, that occurs naturally and that has a viscosity of at least 10 cP (centipoise) at initial reservoir conditions. Viscous oil includes oils generally defined as "heavy oil" or "bitumen". Bitumen is classified as an extra heavy oil, with an API gravity of about 10° or less, referring to its gravity as measured in degrees on the American Petroleum Institute (API) Scale. Heavy oil has an API gravity in the range of about 22.3° to about 10°. The terms viscous oil, heavy oil, and bitumen are used interchangeably herein since they may be extracted using similar processes.

[0023] *In situ* is a Latin phrase for “in the place” and, in the context of hydrocarbon recovery, refers generally to a subsurface hydrocarbon-bearing reservoir. For example, *in situ* temperature means the temperature within the reservoir. In another usage, an *in situ* oil recovery technique is one that recovers oil from a reservoir within the earth.

[0024] The term “formation” as used herein refers to a subterranean body of rock that is distinct and continuous. The terms “reservoir” and “formation” may be used interchangeably.

[0025] During a SDRP, a reservoir accommodates the injected solvent and non-solvent fluid by compressing the pore fluids and, more importantly in some embodiments, by dilating the reservoir pore space when sufficient injection pressure is applied. Pore dilation is

a particularly effective mechanism for permitting solvent to enter into reservoirs filled with viscous oils when the reservoir comprises largely unconsolidated sand grains. Injected solvent fingers into the oil sands and mixes with the viscous oil to yield a reduced viscosity mixture with significantly higher mobility than the native viscous oil. Without intending to be bound by theory, the primary mixing mechanism is thought to be dispersive mixing, not diffusion. Preferably, injected fluid in each cycle replaces the volume of previously recovered fluid and then adds sufficient additional fluid to contact previously uncontacted viscous oil. Preferably, the injected fluid comprises greater than 50% by mass of solvent.

[0026] In the case of a CSDRP, on production, the pressure is reduced and the solvent(s), non-solvent injectant, and viscous oil flow back to the same well and are produced to the surface. As the pressure in the reservoir falls, the produced fluid rate declines with time. Production of the solvent/viscous oil mixture and other injectants may be governed by any of the following mechanisms: gas drive via solvent vaporization and native gas exsolution, compaction drive as the reservoir dilation relaxes, fluid expansion, and gravity-driven flow. The relative importance of the mechanisms depends on static properties such as solvent properties, native GOR (Gas to Oil Ratio), fluid and rock compressibility characteristics, and reservoir depth, but also depends on operational practices such as solvent injection volume, producing pressure, and viscous oil recovery to-date, among other factors. In a SDRP that is not cyclic, production occurs through another well.

[0027] During an injection/production cycle, the volume of produced oil should be above a minimum threshold to economically justify continuing operations. In addition to an acceptably high production rate, the oil should also be recovered in an efficient manner. One measure of the efficiency of a CSDRP is the ratio of produced oil volume to injected solvent volume over a time interval, called the OISR (produced Oil to Injected Solvent Ratio). Typically, the time interval is one complete injection/production cycle. Alternatively, the time interval may be from the beginning of first injection to the present or some other time interval. When the ratio falls below a certain threshold, further solvent injection may become uneconomic, indicating the solvent should be injected into a different well operating at a higher OISR. The exact OISR threshold depends on the relative price of viscous oil and solvent, among other factors. If either the oil production rate or the OISR becomes too low, the CSDRP may be discontinued. Even if oil rates are high and the solvent use is efficient, it is also important to recover as much of the injected solvent as possible if it has economic value. The remaining solvent may be recovered by producing to a low pressure to vaporize

the solvent in the reservoir to aid its recovery. One measure of solvent recovery is the percentage of solvent recovered divided by the total injected. In addition, rather than abandoning the well, another recovery process may be initiated. To maximize the economic return of a producing oil well, it is desirable to maintain an economic oil production rate and OISR as long as possible and then recover as much of the solvent as possible.

[0028] The OISR is one measure of solvent efficiency. Those skilled in the art will recognize that there are a multitude of other measures of solvent efficiency, such as the inverse of the OISR, or measures of solvent efficiency on a temporal basis that is different from the temporal basis discussed in this disclosure. Solvent recovery percentage is just one measure of solvent recovery. Those skilled in the art will recognize that there are many other measures of solvent recovery, such as the percentage loss, volume of unrecovered solvent per volume of recovered oil, or its inverse, the volume of produced oil to volume of lost solvent ratio (OLSR).

[0029] Solvent composition

[0030] The solvent may be a light, but condensable, hydrocarbon or mixture of hydrocarbons comprising ethane, propane, or butane. Additional injectants may include CO_2, natural gas, C3+ hydrocarbons, ketones, and alcohols. Non-solvent co-injectants may include steam, hot water, or hydrate inhibitors. Viscosifiers may be useful in adjusting solvent viscosity to reach desired injection pressures at available pump rates and may include diesel, viscous oil, bitumen, or diluent. Viscosifiers may also act as solvents and therefore may provide flow assurance near the wellbore and in the surface facilities in the event of asphaltene precipitation or solvent vaporization during shut-in periods. Carbon dioxide or hydrocarbon mixtures comprising carbon dioxide may also be desirable to use as a solvent.

[0031] In one embodiment, the solvent comprises greater than 50% C_2-C_5 hydrocarbons on a mass basis. In one embodiment, the solvent is primarily propane, optionally with diluent when it is desirable to adjust the properties of the injectant to improve performance. Alternatively, wells may be subjected to compositions other than these main solvents to improve well pattern performance, for example CO_2 flooding of a mature operation.

[0032] Phase of injected solvent

[0033] In one embodiment, the solvent is injected into the well at a pressure in the underground reservoir above a liquid/vapor phase change pressure such that at least 25

mass % of the solvent enters the reservoir in the liquid phase. Alternatively, at least 50, 70, or even 90 mass % of the solvent may enter the reservoir in the liquid phase. Injection as a liquid may be preferred for achieving high pressures because pore dilation at high pressures is thought to be a particularly effective mechanism for permitting solvent to enter into reservoirs filled with viscous oils when the reservoir comprises largely unconsolidated sand grains. Injection as a liquid also may allow higher overall injection rates than injection as a gas.

[0034] In an alternative embodiment, the solvent volume is injected into the well at rates and pressures such that immediately after halting injection into the injection well at least 25 mass % of the injected solvent is in a liquid state in the underground reservoir. Injection as a vapor may be preferred in order to enable more uniform solvent distribution along a horizontal well. Depending on the pressure of the reservoir, it may be desirable to significantly heat the solvent in order to inject it as a vapor. Heating of injected vapor or liquid solvent may enhance production through mechanisms described by "Boberg, T.C. and Lantz, R.B., "Calculation of the production of a thermally stimulated well", JPT, 1613-1623, Dec. 1966. Towards the end of the injection cycle, a portion of the injected solvent, perhaps 25% or more, may become a liquid as pressure rises. Because no special effort is made to maintain the injection pressure at the saturation conditions of the solvent, liquefaction would occur through pressurization, not condensation. Downhole pressure gauges and/or reservoir simulation may be used to estimate the phase of the solvent and other co-injectants at downhole conditions and in the reservoir. A reservoir simulation is carried out using a reservoir simulator, a software program for mathematically modeling the phase and flow behavior of fluids in an underground reservoir. Those skilled in the art understand how to use a reservoir simulator to determine if 25% of the injectant would be in the liquid phase immediately after halting injection. Those skilled in the art may rely on measurements recorded using a downhole pressure gauge in order to increase the accuracy of a reservoir simulator. Alternatively, the downhole pressure gauge measurements may be used to directly make the determination without the use of reservoir simulation.

[0035] Although preferably a SDRP is predominantly a non-thermal process in that heat is not used to reduce the viscosity of the viscous oil, the use of heat is not excluded. Heating may be beneficial to improve performance or start-up. For start-up, low-level heating (for example, less than 100°C) may be appropriate. Low-level heating of the solvent

prior to injection may also be performed to prevent hydrate formation in tubulars and in the reservoir. Heating to higher temperatures may benefit recovery.

[0036] Synchronization

[0037] Generally, an aspect of the present invention provides a method for recovering hydrocarbons, for instance viscous oil, from an underground reservoir, using a solvent-dominated recovery process. Whether cyclic or non-cyclic, a viscosity reducing solvent is injected and oil and solvent are produced. Unlike steam-dominated recovery processes, solvent-dominated recovery processes cause viscous fingering which should be controlled. By operating wells within a group in-synch and operating wells in adjacent groups out-of-synch, viscous fingering can be controlled.

[0038] Much of the research literature and patents that discuss viscous oil recovery processes focus on idealized processes as if they would be carried out for a single well. For steam-dominated recovery schemes, the viscous oil recovery process appropriate for a single well is often the recovery process appropriate for a multi-well development because well-well interactions are not strongly affected by well-to-well viscous fingering and recovery of the injectant (water) is not required. However, for solvent-dominated recovery schemes, the desired process for a multiwell development is different than for single well development. As solvent is injected into the formation, solvent fingers form which can, relatively early in the life of the field, stretch out 100 meters or more and connect up with other wells. If the well injection and production cycles are not sufficiently synchronized, solvent may rapidly flow from one well to the other when one is on production and the other is on injection and have a negative impact on solvent efficiency and consequent oil recovery. Loss of solvent is also a risk that should be mitigated.

[0039] Figure 1 shows how viscous fingering can lead to poor field sweep in a solvent-dominated process. The figure is a series of top views of a subsurface region of a reservoir penetrated by two horizontal wells. The left portion of Figs. 1a, 1b, and 1c show the inter-well region at the end of an injection cycle and the right portion of Figs. 1a, 1b, and 1c show the inter-well region at the end of a production cycle. Each of the three Figures contains one or two wells (100) undergoing synchronized flow operations, a previously swept portion of the reservoir (101), a region invaded by solvent during the current cycle (102), and the remaining unswept viscous oil (103). Fig. 1a shows that adequate solvent conformance is obtained if the wells are synchronized and there is no poorly managed fingering. All of the fingers are of roughly equal size. As a result, although some residual oil (103) may remain,

the sweep is adequate. Fig. 1b shows the resulting field sweep if there is uncontrolled fingering close to the heel (top portion in figure) of the well. The amount of unswept oil (103) may be substantial in this case. Fig. 1c shows the resulting field sweep if there is uncontrolled fingering at some point along the well, perhaps due to asynchronous operation or the presence of a high permeability streak. Again, the amount of unswept oil (103) may be substantial in this case. One of the two wells is colored white (well 104) to indicate that it has been operated out-of-synch with well 100.

[0040] The term "in-synch" means that wells, or groups of wells, are undergoing the same flow operation, where a flow operation is injection, production, soaking, or idling. Conversely, the term "out-of-synch" means that two wells or groups of wells are not undergoing the same flow operation at the same time. Figure 2 illustrates the concept of synchronized vs. unsynchronized operations using two wells and three flow operations. The flow operations are producing (200), injecting (201), and soaking (or idle) (202). If the two wells are undergoing the same flow operation they are said to be in-synch (203). If they are not undergoing the same flow operation they are out-of-synch (204).

[0041] Injection is the process of flowing fluid from the surface towards the reservoir. Production is the process of flowing fluid from the reservoir towards the surface. Idling is the process of not flowing a well, and soaking is a special case of idling where a well idles after it has recently undergone injection.

[0042] Injection and production are considered to be opposite flow operations. Injection and soaking (or idling) are considered to be different, but not opposite, flow operations. Likewise, production and soaking (or idling) are considered to be different, but not opposite, flow operations. This distinction is important since opposite flow operations of nearby wells can significantly contribute to undesirable channeling.

[0043] In addition to describing whether wells are in-synch or out-of-synch at a given time, we can say that wells are "substantially in-synch", if they are undergoing the same flow operation of injection or production for more than 80% of fluid flow on a mass basis. Fluid flow means the amount of fluid injected and produced over the wells of interest. For example, if during an operational period there is a group of three wells of which two are injecting and one is producing, the wells are substantially in-synch during the operational time period if the mass of fluid injected divided by the sum of the mass of fluid injected and produced is greater than 80%. Even though the producing well is out-of-sync for all of the time period, because the producing well flows at a flow rate that is low compared to the

injecting wells, the interaction is not particularly unfavorable. In alternative embodiments, this value of 80% becomes 90%, or 95%.

[0044] Wells are also "substantially in-synch" if they are undergoing opposite flow operations for less than 10% of fluid flow on a mass basis. For example, if during an operational time period there is a group of four wells of which two remain idle during the time period, one injects for a time and produces for a time, and another produces for the entire time period, the wells are substantially in-synch during the operational time if the mass of fluid that flowed while the wells had opposite flow behavior divided by the total mass of fluid that flowed during the entire time period is less than 10%. In alternative embodiments, this value of 10% becomes 5%, or 1%. Wells are "substantially in-synch" if either of the above two criteria is met, or if both of the above two criteria are met.

[0045] While it is preferred that every well of a group undergo the same flow operation of injection or production for more than 80% of the time, it may be acceptable to have, say, one or two of wells in the group undergoing different, and even opposite, flow operations provided that the remaining wells maintain even higher levels of synchronization, such as being synchronized for more than 90%, or more than 95% of the time.

[0046] The special case of a single well within a group undergoing injection or production while all other wells in the group are idle is also considered to be "substantially in-synch" because for the duration of injection or production there is not an opposite flow behavior occurring within the group. In one embodiment, for at least 80% of fluid flow on a mass basis, a single well within at least one group undergoes injection and production while the remaining wells within the at least one group are idle.

[0047] Wells are "substantially out-of-synch" if more than 10% of fluid flow on a mass basis occurs during opposite flow operation of injection or production. In alternative embodiments, this value of 10% becomes 25%, 50%, 75%, or 90%. Adjacent well groups are "substantially out-of-synch" if wells of adjacent well groups undergo opposite flow operation of injection or production for more than 10% of fluid flow on a mass basis. In alternative embodiments, this value of 10% becomes 25%, 50%, 75%, or 90%.

[0048] While "substantially in-synch" and "substantially out-of-synch" have been defined using fluid flow on a mass basis, one way to achieve this is by using time synchronization. For example, during "substantially in-synch" operation, wells within a group can undergo the same flow operation of injection or production for more than 80%, more than 90%, or more than 95% of an operational time, and/or wells within a group can undergo

opposite flow operations of injection or production for less than 10%, less than 5%, or less than 1% of an operational time. Likewise, during "substantially out-of-synch" operation, wells of adjacent groups can undergo opposite flow operation of injection or production for more than 10%, more than 25%, more than 50%, more than 75%, or more than 90% of an operational time. Time synchronization is a convenient, but not essential, way to achieve mass flow synchronization and therefore in the discussion that follows most of the discussion relates to time synchronization.

[0049] Prior descriptions of CSDRPs have not addressed how to operate a multiwell application. Furthermore, descriptions of solvent-dominated processes other than CSDRPs have also not described how to space, arrange, and orient wells undergoing solvent injection.

[0050] Well orientation is notable because two nearby wells can experience injector-to-producer channeling of injected solvent if they are operated out-of-synch. Channeling is a fluid flow phenomenon in which fluid flowing from one point to another strongly prefers to flow along a particular route. In an oil recovery process, channeling may be detrimental because it prevents the injectant from flowing through and consequently sweeping oil from a large area of the reservoir. Even though injected solvent and injected steam both have adverse mobility ratios when injected into highly viscous oil, the channeling effect is particularly acute in solvent-dominated processes, more so than in steam-based processes, and more so than is generally appreciated by those skilled in the art.

[0051] Viscous fingers typically follow pressure gradients, moving from regions of relatively higher to relatively lower pressure. If neighboring wells inject simultaneously, and at about the same pressure, then there is no pressure gradient to drive flow from one well to another. Therefore, one channeling minimization strategy is to have all the wells in the field synchronized. Although effective at maximizing solvent efficiency and field sweep, this strategy may be impractical for several reasons. First, solvent is preferably supplied to the field at a relatively constant rate to minimize transportation cost. Second, various wells will perform differently due to geologic and other heterogeneities.

[0052] Several approaches to minimize channeling and therefore improve field sweep are discussed herein. None have the drawback of full synchronization across the field. All variants may be combined with the principal approach. The approaches are:

1. <u>Principal approach:</u> Division of a set of wells into groups using buffer zones with operational synchronization within each group (but not between groups);
2. Reduce buffer size and operate neighboring groups more nearly in-synch;

3. Regardless of grouping strategy, orient wells with regard to geological considerations;
4. Create artificial buffers using pressure maintenance wells;
5. Allow individual wells within a group to idle or soak.

Divide up the wells into groups and synchronize the wells within a group

[0053] The principal approach is to divide up the wells into groups and synchronize the wells within a group and offset the synchronization with other groups to increase the uniformity of solvent demand. These groups can be largely isolated from each other by having undeveloped buffer zones between the groups. For instance, these buffer zones may be 200 meters or more wide to largely ensure isolation. The value "200 meters" is provided merely by way of example and the size of suitable buffer zones will depend on certain factors, such as geologic factors and injection rates.

[0054] An example of a group-based well arrangement compatible with synchronized operations is shown in Fig. 3. The illustration is a top view perspective of the subsurface region comprising the horizontal wells (301). The well length (302) is shown. In Fig. 3, four wells are shown in one group (304), although the groups could comprise as few as two wells or more than four wells. The group of wells (304) is enclosed by a thin, black line. The wells within the group are separated from one another by some distance, termed the "well spacing" (303). The group of four wells is part of a field development which includes many groups. Together the groups are referred to as a "set". The "set" does not necessarily include all wells in a particular operation. A portion of three neighboring groups (305, 306, and 307) is shown in Fig. 3, but the set could comprise more groups. For the purposes of associating a reservoir region with a group of wells, a dotted line (300) has been drawn to indicate the reservoir region that may reasonably be expected to contain injected solvent associated with the group of wells, and is referred to herein as a "block boundary". The wells within a block boundary are not necessarily drilled from the same well pad. The groups are separated by separation distances, a side-to-side separation distance separating groups along the length of the wells, and an end-to-end separation distance, separating groups at the toe and heel portions of the well. The double-ended arrow 308 indicates the length of the side-to-side separation distance and double-ended arrow 309 indicates the length of the end-to-end separation distance. If the separations are large enough, a buffer zone is created that contains a reservoir region that remains uninvaded by solvent. The width of the side-to-side

buffer zone is indicated by the double ended arrow 310 and the end-to-end buffer zone 313. During the course of operation, solvent (filling dotted area 311) may invade a portion of or the entire region bounded by the block boundary. The reservoir region outside the block boundary is the buffer zone. An alternate way to define the width of the side-to-side buffer zone is to subtract the well spacing (303) from the side-to-side separation distance (308). The areas that are uninvaded by solvent are not denoted with any special pattern and are left as whitespace (312). In subsequent figures, both side-to-side and end-to-end buffer zones may be referred to collectively.

[0055] Fig. 4 shows a well arrangement and operation according to one embodiment. The arrangement of wells in Fig.4 is similar to the arrangement in Fig.3 and includes bounded groups of horizontal wells of some length separated by buffers. For brevity and clarity, labels are not affixed to all components of Fig 4. In Fig. 4, the wells are grouped into groups of 10 wells each. Of course, the value "10 wells" is merely provided by way of example. Groups may be as small as a well pair (2 wells) or as large as the solvent supply allows, for example, up to about 16. Wells within a given group of wells are synchronized or nearly so, preferably in-synch for more than 80%, more than 90%, or more than 95% of the time, or alternatively where one well within a group is not producing while another well in the group is injecting. Wells within a group may be unsynchronized for short periods of time of up to perhaps a few weeks, but it is preferred to operate synchronously during most of the operational life of the wells, which my be a period of years. Fig. 4 shows 10 wells (401a) of group 401 and 10 wells (402a) of group 402. The 10 wells (401a) within one group (401) are synchronized with each other or nearly so. All ten wells within the group have the same shading (whitespace as fill). The black-colored wells (402a) in neighboring group 402 are "out-of-synch" with the wells (401a) but are in-synch within their own group (402). The wells (403a, 404a) of the other two groups (403, 404) are in-synch with the wells of group 402 and out-of-synch with the wells (401a) of group 401. The groups are separated by the side-to-side (405) and end-to-end (406) separation distances. Research using reservoir simulation indicates that side-to-side and end-to-end buffer zones of widths 410 and 413, respectively, may prevent undue well-to-well interaction (i.e. channeling), should the wells in a neighboring group be out-of-synch.

[0056] Though the buffer zones are desirable to prevent undue well interaction, the prevention or reduction of well interaction comes at a cost because oil recovery is higher inside the block boundary (400) than in the buffer region. Recovery is highest in the region

between wells of the same group. The buffer region, by design, is entirely or mostly not invaded by solvent (412). In order to maximize overall field recovery, it is desirable that the area of the block (enclosed by the dotted line 400) be substantially larger than the area of the neighboring buffer zones. A larger number of wells per group and long well length aid in increasing the area that comprises a block. It is preferred that buffers comprise no more than one third, or no more than 10%, of the combined area of a block and its neighboring buffer zones. One way to estimate the fraction of the area occupied by the buffers is to a) multiply the length of each side of the four-sided block boundary (400) by the width of the buffer zone on that side (for example, lengths 413 and 410) b) divide the area by 2 to account for it being shared between two groups c) add the resulting areas for all four sides together to get the total buffer zone area and then d) divide the total buffer zone area by the sum of the total buffer zone area and the area enclosed by the block boundary. Those skilled in the art will recognize alternate ways to estimate a fraction of area occupied by the buffers. There is a balance between obtaining synchronization over a large area and increasing net solvent demand uniformity. The arrangement of Fig. 4 shows one way to obtain a preferred balance. If there is no neighboring group (there are no neighboring wells) or the neighboring groups are kept somewhat synchronized, the size of the illustrated side-to-side separation could be reduced to the interwell spacing without significant negative impact to field recovery.

[0057] While well groups are often shown and discussed herein to be separated by buffer zones, this is not essential. For instance, two well groups may be separated by one or more wells undergoing a different, but not opposite, flow behavior for a substantial portion of the operation. Injection and production are defined as opposite flow behavior. Flow behaviors that are not opposite are 1) idling with any other of the flow behaviors or 2) soaking with any of the other flow behaviors. Effectively, wells undergoing idling or soaking act as buffers. It is acceptable to soak or idle in conjunction with injection and production.

[0058] Selection of the block size is important for reducing solvent storage, fully utilizing a constant solvent supply, and maintaining high field sweep. The block size depends on the number of wells, their length, the well spacing, and the length of the buffers that separate wells. In synchronized operation, the number of blocks is controlled by the ratio of producers to injectors. The number of blocks is equal to the number of groups.

[0059] Wells operated within a group are expected to interact and within the group, if the wells are in-synch or nearly in-synch, high recovery can be achieved. Buffers need to be

sized so that wells from different groups will not significantly interact. The average number of wells on production per well on injection during a period of field operation depends on the solvent recovery factor (SR) and the ratio of the average injection (Q_{inj}) to average production rates (Q_{prod}) over the operational period,

$$\text{number of producers per injector} = SR(Q_{inj}/Q_{prod}).$$

[0060] For example, if average injection rate over several injection phases is 500m^3 solvent/day/well, average solvent production rate over several production phases is 100m^3/day/well, average solvent recovery over several cycles is 80%, and wells are not soaked, then there should be 4 wells (0.80 x 500/100) on production for every well on injection.

[0061] In order to maintain synchronization and a high block area to buffer area ratio, 4-10 wells is a good size for a group of synchronized wells. Therefore, using a 4:1 producer/injector ratio, a field of 30 wells might be designed with 5 groups of 6 wells each such that 4 groups of wells (24 wells total) are on production and one group (6 wells total) is on injection. The group of 6 wells on injection will require 2400 m^3/day (24 wells x 100 m^3/day/well) of recycled solvent plus 600m^3/day of makeup solvent volume.

[0062] Preferred arrangements and/or operations can be further defined by understanding what is not preferred. Figs. 5 to 8 all show arrangements and/or operations that are not preferred. For brevity and clarity, labels are not affixed to all elements of Figs. 5 to 8. Figs. 5 to 8 contain many of the same elements (for example, wells, block boundaries, and buffers) as Figs. 3 and 4. Where important for discussion, individual elements of the Figs. are labeled.

[0063] Fig. 5 shows a well arrangement and operation with buffers that is sufficient for isolating synchronized groups, but the groups are too small, and consequently the total area of the block as defined by the block boundary (500) is small in comparison to the area of the buffers. The in-synch well group (501) and neighboring well group (502) that is out-of-synch with 501 (but in-synch within 502) are shown. The recovery efficiency from such an arrangement and operation will be less than that shown in Fig. 4.

[0064] Fig. 6 shows an inefficient use of buffer zones. The wells (600a, 601a) of two neighboring groups (600 and 601) are synchronized both within the groups and between the groups. If the wells are being operated such that two neighboring groups are always or nearly synchronized, there is no need for a sizeable buffer (606) to separate them. The wells of groups 602 and 603 are synchronized with each other, but not with groups 600 and 601.

The buffer separating group 600 from 601 and separating 602 from 603 is not needed. Its presence lowers field sweep.

[0065] Fig. 7 shows poor operation of a well group (701). The wells within the group (701) are not fully synchronized. Injector wells (701a) are out-of-synch with producer wells (701b) within the same group. As a result, channeling of solvent from the injectors to the producers may occur, as indicated by presence of solvent (711) fingering. It is highly undesirable to be injecting and producing from wells within the same group. In the remaining three synchronized groups in the figure, no channeling is observed.

[0066] Fig. 8 shows an operation of a group (801) that is less efficient. Wells within the same group (801) are immediately adjacent but not synchronized. Wells (801a) are injecting while the neighboring wells (801b) within the group are producing Such wells should be separated by a buffer or kept more nearly in-synch. Some channeling of solvent (811) is observed from the injectors (801a) to the producers (801b). Neither the injection (801a) wells or the producing wells (801b) are in-synch with the unlabeled wells in Fig 8.

Reduce buffer size and operate neighboring groups more nearly in-synch

[0067] Alternatively, the buffer zones may be significantly reduced in width if neighboring groups are only slightly out-of-synch. In this concept, the total portion of time in which two neighboring groups are in-synch is substantial, that is, more than 50% of the time (or more than 30%, more than 40%, more than 60%, or more than 70% of the time). These values could equally be applied on a fluid flow mass basis. Two wells or two groups are said to be "in-synch" if they are undergoing the same flow operation, where a flow operation is injection, production, soaking, or idling. A particularly advantageous way to define well groups is to define a row of horizontal wells as a group. Fig. 2 illustrates the concept of synchronization for individual wells, but the concept is also applicable to groups of wells.

[0068] This is somewhat similar to the "megarow strategy" employed for cyclic steam stimulation (CSS) at Cold Lake, Alberta, Canada (see Society of Petroleum Engineering (SPE), Reference No. 25794). However, this approach still leads to significant communication between groups of wells and inefficient use of steam (or solvent) late in the field life. The "megarow strategy" as used for CSS is not directly translatable to CSDRPs since it is for rows of vertical wells and the preferred mode of operation for CSDRP wells uses relatively horizontal wells.

Orient wells with respect to geologic considerations

[0069] The geological stress state can impact the growth of the viscous fingers that may connect wells. To retard lateral finger growth, wells may be oriented along the maximum horizontal stress direction within the reservoir. As a result, the fluid pressure within a lateral finger must work against the maximum horizontal stress (and the overburden stress) to open up more void space to further allow finger growth. Thus, the greater the horizontal stress, the more finger growth is retarded since the amount of energy expenditure required to grow a finger is greater. In contrast, if the well orientation is opposite to the preferred orientation, namely, aligned along the minimum horizontal stress direction, the fluid pressure within lateral fingers is working against the minimum horizontal stress and the overburden stress to open up more void space. By comparing these two well orientations, one can see that the preferred well orientation results in larger resistance for opening up the void space in lateral fingers, and hence delaying the communication among well groups.

[0070] Figs. 9a and 9b show the orientation of a well (90) in relation to the geologic stress state. The orientation retards finger growth, and, when combined with the well arrangement shown in Figure 4, is a desired well layout for solvent-dominated processes with viscous fingering. In Figs. 9a and 9b, S^h_{max}, and S^h_{min} are the maximum (91) and minimum stress (92), respectively. A cross-sectional view of the lateral finger is shown in Figure 9b. It shows that the stresses applied on the lateral finger (93) are S^h_{max} and the overburden stress (94). This orientation with respect to the stress states is the preferred *in situ* stress combination and will result in maximum compressive loading to suppress finger growth. The solvent chamber (95) is also shown and denoted with a diagonal pattern.

Create artificial buffers using pressure maintenance wells

[0071] Channeling may be minimized by separating out-of-synch well operations with buffer zones, synchronizing well operations, and/or careful placement with respect to the geological stress state. A further means of minimizing channeling, containing the injected solvent within a pattern of wells, and thereby improving field sweep is targeted conditioning of the reservoir stress state using pressure maintenance injection wells. This is accomplished by increasing reservoir pressure prior to and/or during operations where injection and production take place in adjacent wells.

[0072] Fig. 10a shows the channeling that may occur in the absence of a pressure buffer should two wells be undergoing opposite flow operations, namely one well on injection and another on production, while being separated by an insufficient buffer zone. The solvent (1011) fingers from the injector (1001) to the producer (1002). Fig. 10b illustrates the use of a pressure maintenance injector well to minimize channeling within a group of five wells. Fig. 10b shows a well arrangement that is the same as Fig. 10a, except that an additional injector well (1004) is present. In the Fig. 10b the well is shown as a new well, which may be purposefully drilled, in this case midway between the two groups, but that need not be the case. The Fig. 10b also shows the injectant (1006), typically water. Alternatively, a particular well(s) within the existing group may be specifically designated to provide a pressure buffer. The purpose of the pressure maintenance wells is to condition reservoir stress. The fluid injection causes a localized increase in reservoir pressure. The pressure increase results in increased compressive loading of the formation, thereby suppressing finger growth from adjacent solvent injection wells. The buffer well injection pressure should not exceed the fracture pressure of the formation. The use of a non-solvent (for example, water) for injection minimizes pressure leak off to the formation when the injection is halted because the non-solvent is not miscible with the oil or hydrocarbon solvent. This lack of miscibility assists in the ability to hold the targeted pressure increase for the required duration. Non-solvents such as water are also typically cheaper than solvents.

[0073] Alternatively, an inefficient or lower cost solvent could be used in place of a non-solvent to provide the reservoir conditioning. Use of a solvent enables some heavy oil production when the pressure buffer is no longer required and the buffer well produced.

[0074] The injection volume of the non-solvent or inefficient solvent increases with subsequent pressure conditioning operations due to the increased voidage in the reservoir created by the production of oil. Therefore the production of the buffer well, if desired, would need to sufficiently lag the adjacent CSDRP wells so as not to adversely affect the production of the CSDRP wells.

[0075] Pressure maintenance by injection need not be constrained to the target hydrocarbon-bearing reservoir. In the case where gas or water zones are adjacent (overlying / underlying or edge) to the hydrocarbon-bearing reservoir, it may be beneficial for pressure maintenance wells to target the adjacent gas/water zones in order to increase formation pressure and suppress the solvent finger growth into the vicinity of potential 'thief' zones of injected solvent.

[0076] The field may contain a large set of wells. The subset of wells used as pressure maintenance wells need not be fixed through the life of the field operation. As part of the evolving reservoir depletion plan new buffer wells may be drilled, existing injection or production wells may be converted to buffer wells, or buffer wells may be retired or converted to injection or production wells. All of these changes may enhance recovery. In particular, buffer wells may need to be placed between injecting and producing wells as a CSDRP field operation matures. Such placement assists solvent containment by removing or reducing the steep pressure gradient that may exist between CSDRP wells undergoing opposite flow operations.

[0077] The procedure of drilling a new well offset to an existing well or drilling a new well between two existing wells is often called infill drilling. A pressure maintenance well is therefore a kind of infill well. The drilling of other types of infill wells, such as wells whose purpose is to produce oil or inject solvent, may also be advantageous.

[0078]

Well layout alternatives

[0079] The arrangement in Fig. 4 may be varied. For instance, the wells need not be parallel or perpendicular to the boundary and buffer, and may deviate by, for instance, up to 30°. Also, Fig. 4 shows the neighboring groups (403, 404) as synchronized with group 402, but because of the good buffer zone isolation, the neighboring groups could be injecting or producing in an out-of-synch manner. Each group does not necessarily have to have the same number of wells. Likewise, the buffer zones need not be the same size over the field.

[0080] In Figs. 3 through 10 all of the block boundaries were shown as rectangular and the side-to-side and end-to-end separations were shown as equal on both sides of a group. The block boundaries need not be rectangular and the separations need not be equal. For example, there may be geological features such as 'channel boundaries' that may be utilized to reduce separation between groups on one side of a group. These geological features act as artificial buffers, eliminating the need to leave a substantial buffer. Boundary dimensions may be adjusted to account for communication or stress trends. If communication is detected between wells of different groups, injection volumes may be reduced on the communicating boundary wells. In order to detect such communication there may be pressure monitoring of boundary or observation wells. If measurements of the stress state indicate that viscous fingering may be enhanced, the buffer size may be increased on one side of a group. The presence of significant fractures may also be a reason to increase

the size of the buffers. "Geological buffer zone" as used herein means a naturally occurring zone acting as a buffer zone, such as a sealing fault or channel boundary. A "channel boundary" as used herein means the boundary between two rock formations, one rock formation consisting of a channel filled with relatively permeable rock, and the other formation consisting of a different and less permeable rock. A sealing fault is a fault that effectively seals off flow from one side of the fault of the other.

[0081]

Allowing individual wells to within a group to idle or soak

[0082] Regardless of the particular orientation and grouping strategy, a scheme for overcoming some of the drawbacks associated with group synchronization or near-synchronization is desirable. One such drawback is that synchronization can reduce overall efficiency by extending production or injection from wells no longer efficiently performing. In one embodiment, specific wells within a group are temporarily shut-in. In particular, if during production, a specific well within a group starts producing gas at rate above a pre-set value, the well is temporarily shut-in until the overall performance of the entire group to which the well belongs reaches a pre-set threshold (for example, gas production rate or total oil production rate). In this way, overall efficiency of solvent use (for example, produced oil to injected solvent ratio) may be improved by preventing a poorly performing well or a fast producing well from overly-dictating the cycle schedule for the set of wells to which it belongs.

[0083] Table 1 outlines the operating ranges for CSDRPs of some embodiments. The present invention is not intended to be limited by such operating ranges.

[0084] Table 1. Operating Ranges for a CSDRP.

Parameter	Broader Embodiment	Narrower Embodiment
Injectant volume	Fill-up estimated pattern pore volume plus 2-15% of estimated pattern pore volume; or inject, beyond a pressure threshold, for a period of time (for example weeks to months); or inject, beyond a pressure threshold, 2-15% of	Inject, beyond a pressure threshold, 2-15% (or 3-8%) of estimated pore volume.

	estimated pore volume.	
Injectant composition, main	Main solvent (>50 mass%) C_2-C_5. Alternatively, wells may be subjected to compositions other than main solvents to improve well pattern performance (i.e. CO_2 flooding of a mature operation or altering *in situ* stress of reservoir).	Main solvent (>50 mass%) is propane (C_3).
Injectant composition, additive	Additional injectants may include CO_2 (up to about 30%), C_{3+}, viscosifiers (for example diesel, viscous oil, bitumen, diluent), ketones, alcohols, sulphur dioxide, hydrate inhibitors, and steam.	Only diluent, and only when needed to achieve adequate injection pressure.
Injectant phase & Injection pressure	Solvent injected such that at the end of injection, greater than 25% by mass of the solvent exists as a liquid in the reservoir, with no constraint as to whether most solvent is injected above or below dilation pressure or fracture pressure.	Solvent injected as a liquid, and most solvent injected just under fracture pressure and above dilation pressure, $P_{fracture} > P_{injection} > P_{dilation} > P_{vaporP}$.
Injectant temperature	Enough heat to prevent hydrates and locally enhance wellbore inflow consistent with Boberg-Lantz mode	Enough heat to prevent hydrates with a safety margin, $T_{hydrate}$ + 5°C to $T_{hydrate}$ +50°C.
Injection rate	0.1 to 10 m^3/day per meter of completed well length (rate	0.2 to 2 m^3/day per meter of completed well length (rate

	expressed as volumes of liquid solvent at reservoir conditions).	expressed as volumes of liquid solvent at reservoir conditions). Rates may also be designed to allow for limited or controlled fracture extent, at fracture pressure or desired solvent conformance depending on reservoir properties.
Threshold pressure (pressure at which solvent continues to be injected for either a period of time or in a volume amount)	Any pressure above initial reservoir pressure.	A pressure between 90% and 100% of fracture pressure.
Well length	As long of a horizontal well as can practically be drilled; or the entire pay thickness for vertical wells.	500m – 1500m (commercial well).
Well configuration	Horizontal wells parallel to each other, separated by some regular spacing of 60 – 600m; Also vertical wells, high angle slant wells & multi-lateral wells. Also infill injection and/or production wells (of any type above) targeting bypassed hydrocarbon from surveillance of pattern performance.	Horizontal wells parallel to each other, separated by some regular spacing of 60 – 320m.
Well orientation	Orientated in any direction.	Horizontal wells orientated

		perpendicular to (or with less than 30 degrees of variation) the direction of maximum horizontal *in situ* stress.
Minimum producing pressure (MPP)	Generally, the range of the MPP should be, on the low end, a pressure significantly below the vapor pressure, ensuring vaporization; and, on the high-end, a high pressure near the native reservoir pressure. For example, perhaps 0.1 MPa – 5 MPa, depending on depth and mode of operation (all-liquid or limited vaporization).	A low pressure below the vapor pressure of the main solvent, ensuring vaporization, or, in the limited vaporization scheme, a high pressure above the vapor pressure. At 500m depth with pure propane, 0.5 MPa (low) – 1.5 MPa (high), values that bound the 800 kPa vapor pressure of propane.
Oil rate	Switch to injection when rate equals 2 to 50% of the max rate obtained during the cycle; Alternatively, switch when absolute rate equals a pre-set value. Alternatively, well is unable to sustain hydrocarbon flow (continuous or intermittent) by primary production against backpressure of gathering system or well is "pumped off" unable to sustain flow from artificial lift. Alternatively, well is out-of-synch with adjacent	Switch when the instantaneous oil rate declines below the calendar day oil rate (CDOR) (for example total oil/total cycle length). Likely most economically optimal when the oil rate is at about 0.8 x CDOR. Alternatively, switch to injection when rate equals 20-40% of the max rate obtained during the cycle.

	well cycles.	
Gas rate	Switch to injection when gas rate exceeds the capacity of the pumping or gas venting system. Well is unable to sustain hydrocarbon flow (continuous or intermittent) by primary production against backpressure of gathering system with/or without compression facilities.	Switch to injection when gas rate exceeds the capacity of the pumping or gas venting system. During production, an optimal strategy is one that limits gas production and maximizes liquid from a horizontal well.
Oil to Solvent Ratio	Begin another cycle if the OISR of the just completed cycle is above 0.15 or economic threshold.	Begin another cycle if the OISR of the just completed cycle is above 0.3.
Abandonment pressure (pressure at which well is produced after CSDRP cycles are completed)	Atmospheric or a value at which all of the solvent is vaporized.	For propane and a depth of 500m, about 340 kPa, the likely lowest obtainable bottomhole pressure at the operating depth and well below the value at which all of the propane is vaporized.

[0085] In Table 1, embodiments may be formed by combining two or more parameters and, for brevity and clarity, each of these combinations will not be individually listed.

[0086] In the context of this specification, diluent means a liquid compound that can be used to dilute the solvent and can be used to manipulate the viscosity of any resulting solvent-bitumen mixture. By such manipulation of the viscosity of the solvent-bitumen (and diluent) mixture, the invasion, mobility, and distribution of solvent in the reservoir can be controlled so as to increase viscous oil production.

[0087] The diluent is typically a viscous hydrocarbon liquid, especially a C_4 to C_{20} hydrocarbon, or mixture thereof, is commonly locally produced and is typically used to thin bitumen to pipeline specifications. Pentane, hexane, and heptane are commonly components of such diluents. Bitumen itself can be used to modify the viscosity of the injected fluid, often in conjunction with ethane solvent.

[0088] In certain embodiments, the diluent may have an average initial boiling point close to the boiling point of pentane (36°C) or hexane (69°C) though the average boiling point (defined further below) may change with reuse as the mix changes (some of the solvent originating among the recovered viscous oil fractions). Preferably, more than 50% by weight of the diluent has an average boiling point lower than the boiling point of decane (174°C). More preferably, more than 75% by weight, especially more than 80% by weight, and particularly more than 90% by weight of the diluent, has an average boiling point between the boiling point of pentane and the boiling point of decane. In further preferred embodiments, the diluent has an average boiling point close to the boiling point of hexane (69°C) or heptane (98°C), or even water (100°C).

[0089] In additional embodiments, more than 50% by weight of the diluent (particularly more than 75% or 80% by weight and especially more than 90% by weight) has a boiling point between the boiling points of pentane and decane. In other embodiments, more than 50% by weight of the diluent has a boiling point between the boiling points of hexane (69°C) and nonane (151°C), particularly between the boiling points of heptane (98°C) and octane (126°C).

[0090] By average boiling point of the diluent, we mean the boiling point of the diluent remaining after half (by weight) of a starting amount of diluent has been boiled off as defined by ASTM D 2887 (1997), for example. The average boiling point can be determined by gas chromatographic methods or more tediously by distillation. Boiling points are defined as the boiling points at atmospheric pressure.

[0091] In the preceding description, for purposes of explanation, numerous details are set forth in order to provide a thorough understanding of the embodiments of the invention. However, it will be apparent to one skilled in the art that these specific details are not required in order to practice the invention.

[0092] The invention is recited in the claims and should not be limited to preferred embodiments described herein.

WHAT IS CLAIMED IS:

1. A method of operating a cyclic solvent-dominated process for recovering hydrocarbons from an underground reservoir through a set of wells divided into groups of wells, the method comprising:

(a) initiating and subsequently halting injection, into one of the groups of wells, of an amount of a viscosity reducing solvent;

(b) initiating and subsequently halting production, from the one of the groups of wells, of at least a fraction of the solvent and the hydrocarbons from the reservoir, and

(c) cyclically repeating steps (a) and (b) for the groups of wells;

wherein:

each of the groups comprises two or more wells and no well is common between two groups; and

wells of the same group are operated substantially in-synch.

2. The method of claim 1, wherein the wells of the same group undergo opposite flow operation of injection or production for less than 10% of fluid flow on a mass basis.

3. The method of claim 1 or 2, wherein the wells of the same group undergo opposite flow operation of injection or production for less than 5% of fluid flow on a mass basis.

4. The method of any one of claims 1 to 3, wherein the wells of the same group undergo opposite flow operation of injection or production for less than 1% of fluid flow on a mass basis.

5. The method of any one of claims 1 to 4, wherein for at least 80% of fluid flow on a mass basis a single well of at least one group undergoes injection and production while remaining wells within the at least one group are idle.

6. The method of any one of claims 1 to 4, wherein a single well of at least one of group undergoes injection and production while remaining wells within the at least one group are idle.

7. The method of any one of claims 1 to 4, wherein the wells of the same group undergo the same flow operation of injection or production for more than 80% of fluid flow on a mass basis.

8. The method of any one of claims 1 to 4 , wherein the wells of the same group undergo the same flow operation of injection or production for more than 90% of fluid flow on a mass basis.

9. The method of any one of claims 1 to 4, wherein the wells of the same group undergo the same flow operation of injection or production for more than 95% of fluid flow on a mass basis.

10. The method of any one of claims 1 to 4, wherein more than 80% of the wells of the same group undergo the same flow operation of injection or production for more than 80% of an operational time period.

11. The method of any one of claims 1 to 4 and 7 to 10, wherein all wells of the same group undergo the same flow operation of injection or production for more than 80% of an operational time period.

12. The method of any one of claims 1 to 11, wherein adjacent well groups are operated substantially out-of-synch.

13. The method of any one of claims 1 to 12, wherein wells of adjacent well groups undergo opposite flow operation of injection or production for more than 10% of fluid flow on a mass basis.

14. The method of any one of claims 1 to 12, wherein wells of adjacent well groups undergo opposite flow operation of injection or production for more than 25% of fluid flow on a mass basis.

15. The method of any one of claims 1 to 12, wherein wells of adjacent well groups undergo opposite flow operation of injection or production for more than 50% of fluid flow on a mass basis.

16. The method of any one of claims 1 to 12, wherein wells of adjacent well groups undergo opposite flow operation of injection or production for more than 75% of fluid flow on a mass basis.

17. The method of any one of claims 1 to 12, wherein wells of adjacent well groups undergo opposite flow operation of injection or production for more than 90% of fluid flow on a mass basis.

18. The method of any one of claims 1 to 17, wherein immediately after halting injection of the solvent, at least 25 mass % of the injected solvent is in a liquid state in the reservoir.

19. The method of any one of claims 1 to 17, wherein at least 25 mass % of the solvent in step (a) enters the reservoir as a liquid.

20. The method of any one of claims 1 to 17, wherein at least 50 mass % of the solvent in step (a) enters the reservoir as a liquid.

21. The method of any one of claims 1 to 20, wherein each well within the set of wells is oriented within 30° of horizontal within the underground reservoir.

22. The method of any one of claims 1 to 21, wherein, within the underground reservoir, the wells in the set are arranged within 20° of a common horizontal straight line.

23. The method of claim 22, wherein the single common straight line is within 20° of a maximum horizontal stress direction within the reservoir.

24. The method of any one of claims 1 to 23, wherein for at least 25% of the time period between injecting and subsequently halting injection for a group of wells, an adjacent group of wells has at least one well producing; and for at least 25% of the time period between

producing and subsequently halting producing for a group of wells, an adjacent group of wells has at least one well injecting.

25. The method of any one of claims 1 to 23, wherein for at least 50% of the time period between injecting and subsequently halting injection for a group of wells, an adjacent group of wells has at least one well producing; and for at least 50% of the time period between producing and subsequently halting producing for a group of wells, an adjacent group of wells has at least one well injecting.

26. The method of any one of claims 1 to 25, wherein the well groups are separated by buffer zones for limiting well-to-well interaction, wherein buffer zones contain no flowing wells.

27. The method of claim 26, wherein the buffer zones constitute no more than one third of a sum of an area of the groups.

28. The method of claim 26, wherein the buffer zones constitute no more than 10% of a sum of an area of the groups.

29. The method of any one of claims 1 to 28, wherein two wells are separated by an infill well used for increasing hydrocarbon production prior to and/or during operation.

30. The method of any one of claims 1 to 28, wherein two wells are separated by an infill well for increasing reservoir pressure prior to and/or during operation, for limiting well-to-well interaction.

31. The method of claim 29 or 30, wherein water is injected into the infill well.

32. The method of any one of claims 26 to 28, wherein at least certain buffer zones are geological buffer zones.

33. The method of claim 32, wherein the geological buffer zones are channel boundaries.

34. The method of any one of claims 1 to 33, wherein each group comprises a single row of wells.

35. The method of any one of claims 1 to 34, wherein the hydrocarbons are a viscous oil having an *in situ* viscosity of greater than 10 cP at initial reservoir conditions.

36. The method of any one of claims 1 to 35, wherein a common wellbore is used for both the injection and the production.

37. The method of any one of claims 1 to 36, wherein an idle period exists subsequent to halting injection and prior to initiating production.

38. The method of any one of claims 1 to 37, wherein the solvent comprises ethane, propane, butane, pentane, carbon dioxide, or a combination thereof.

39. The method of any one of claims 1 to 38, wherein the solvent comprises greater than 50 mass % propane.

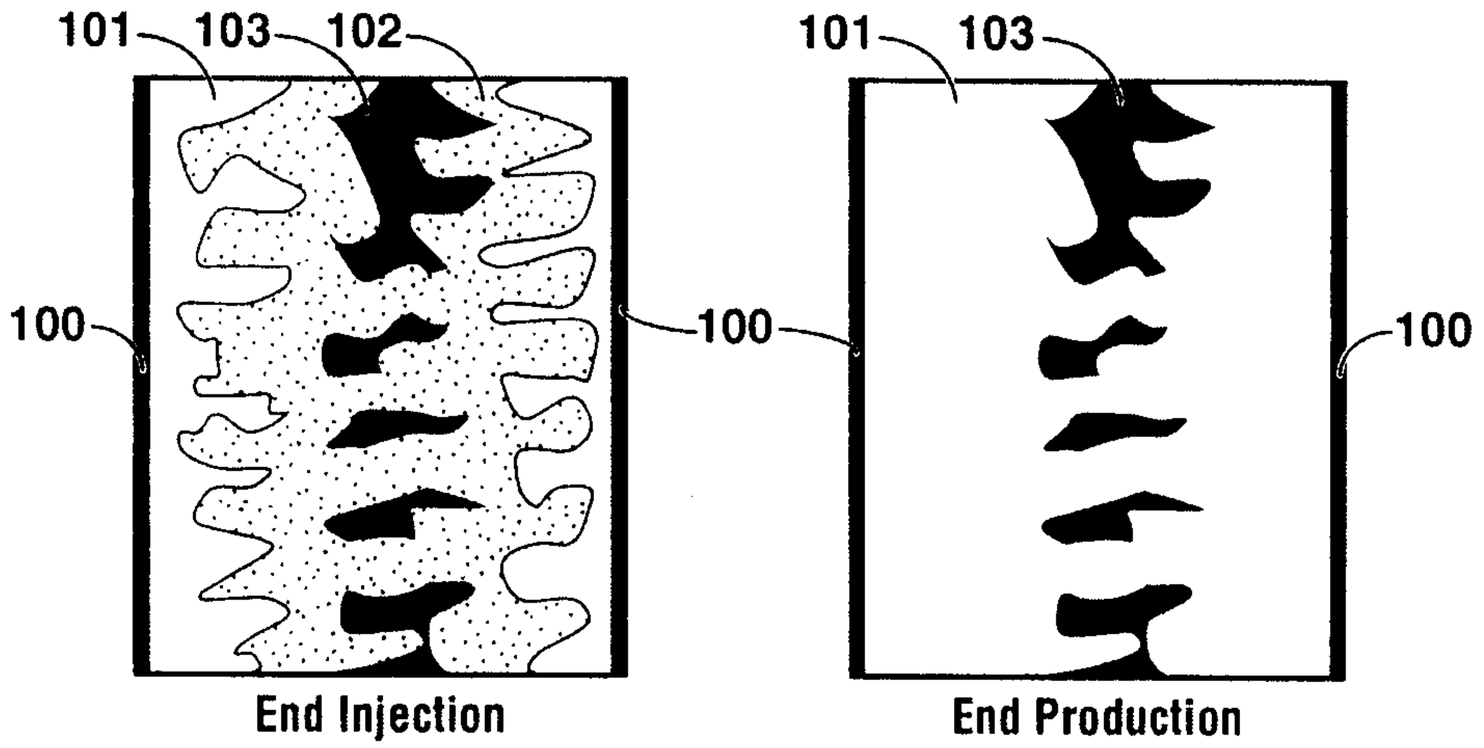


FIG. 1A

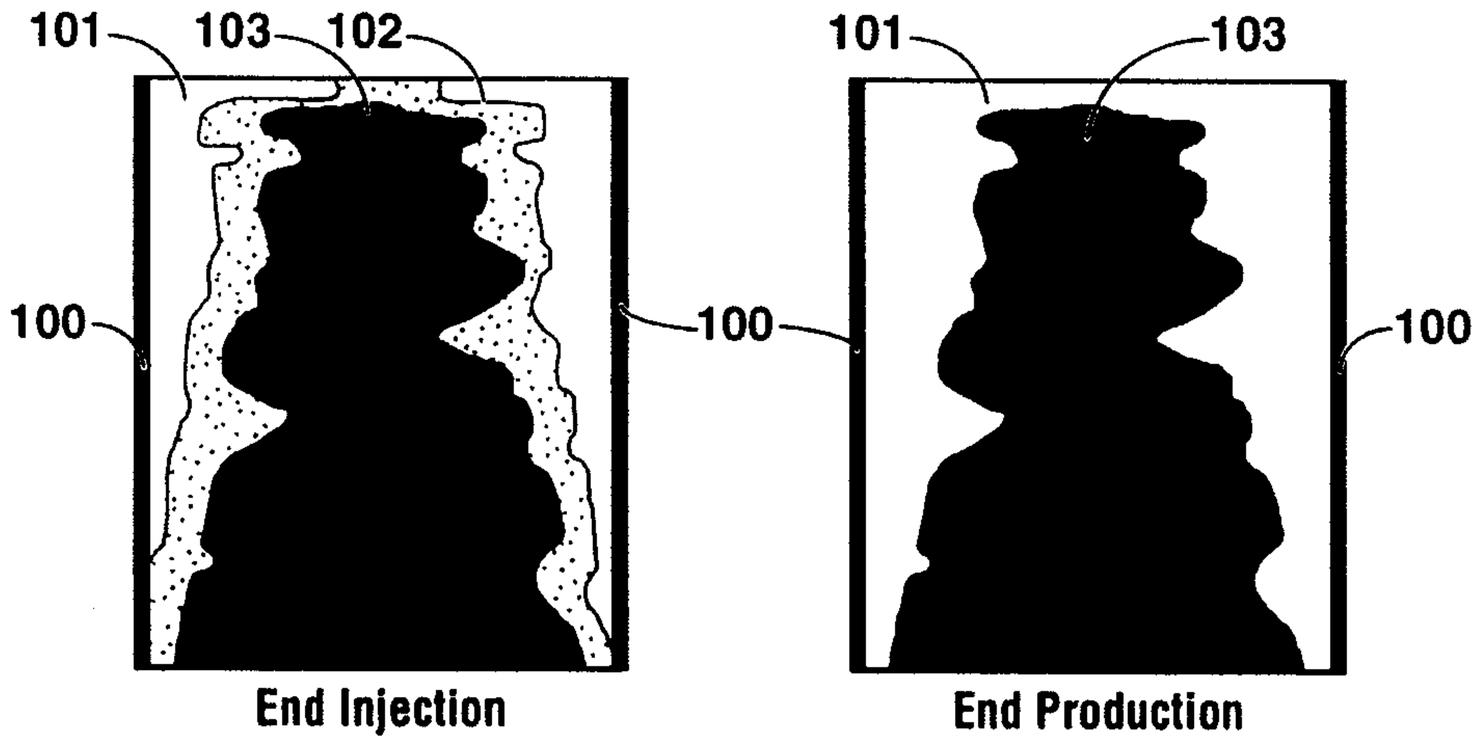


FIG. 1B

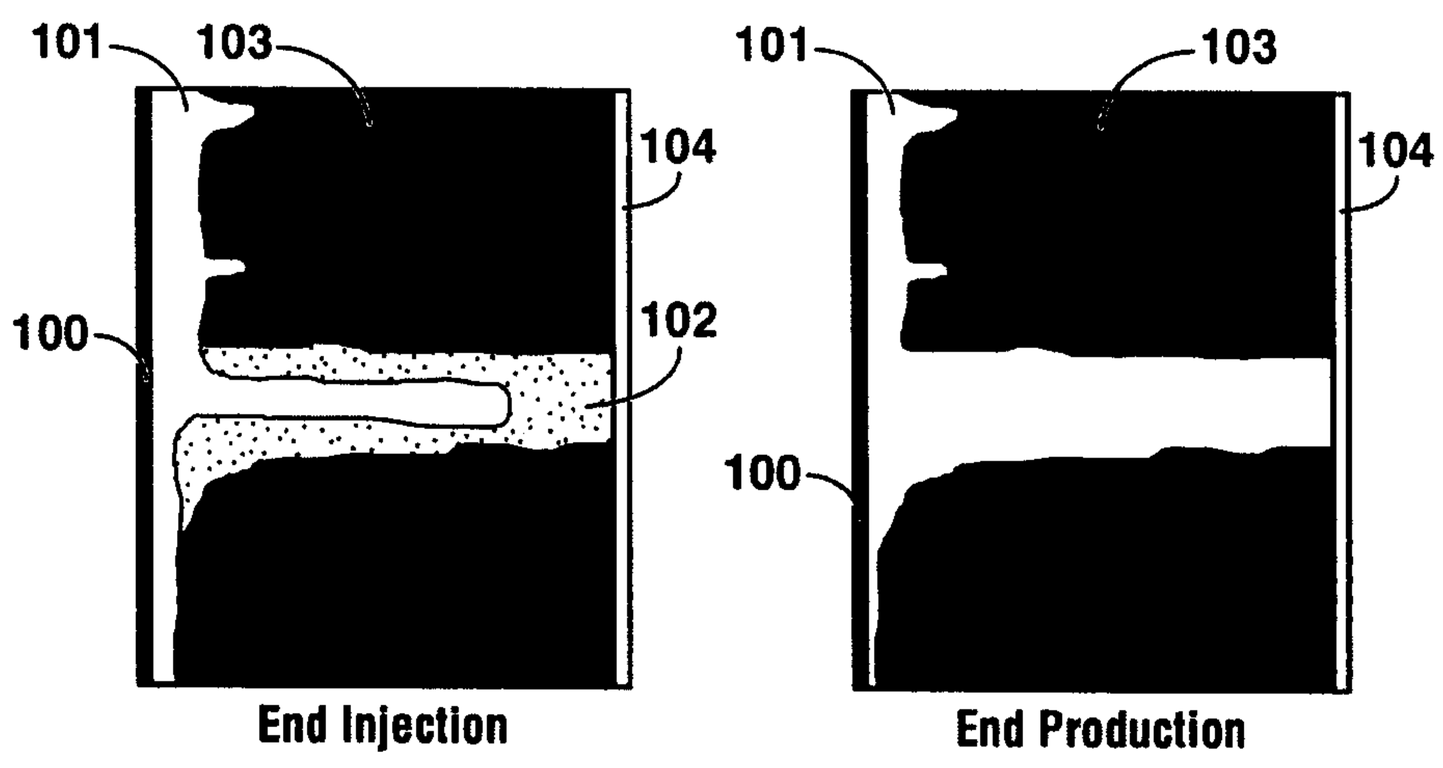


FIG. 1C

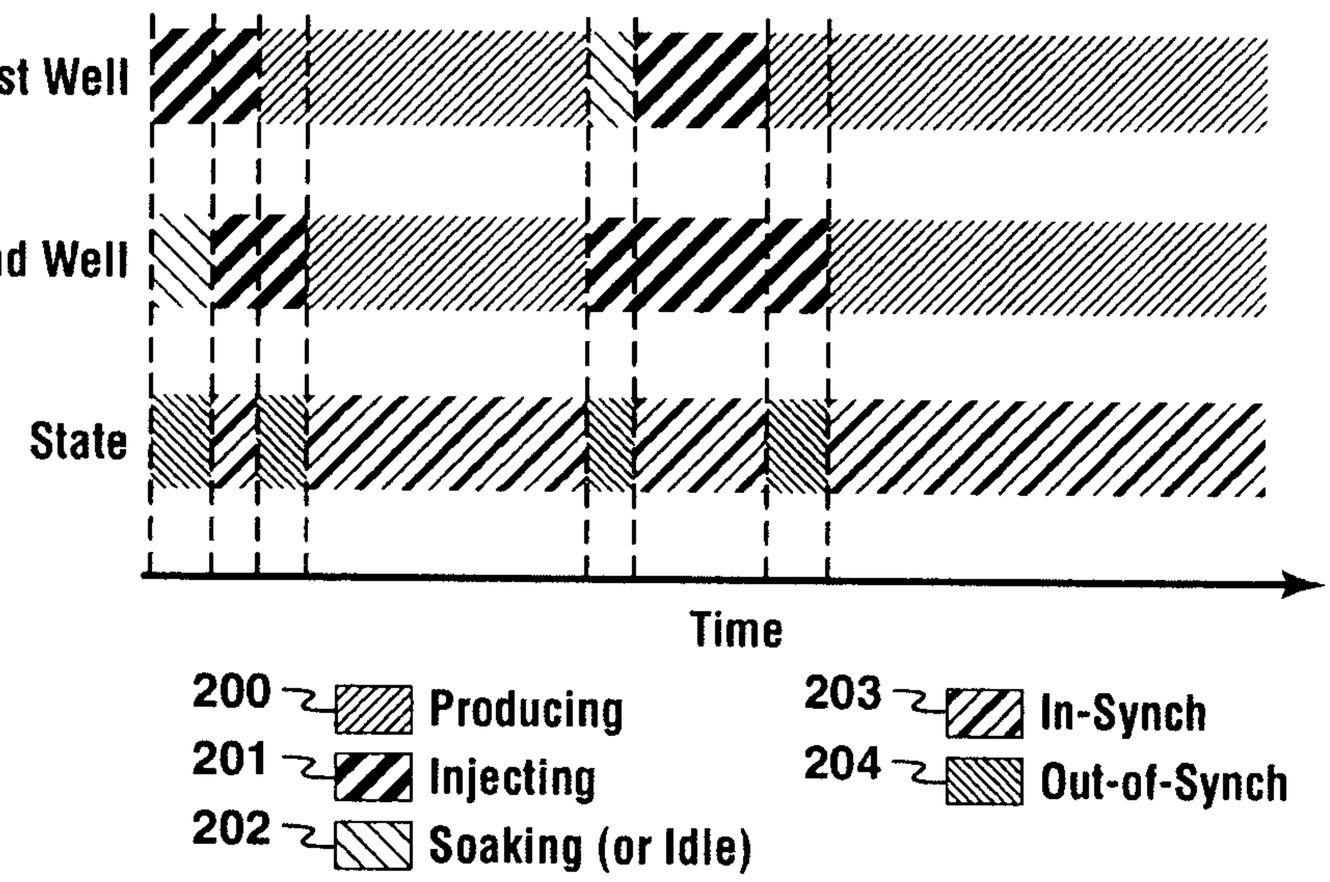

1st Well
2nd Well
State
Time
200 Producing
201 Injecting
202 Soaking (or Idle)
203 In-Synch
204 Out-of-Synch

FIG. 2

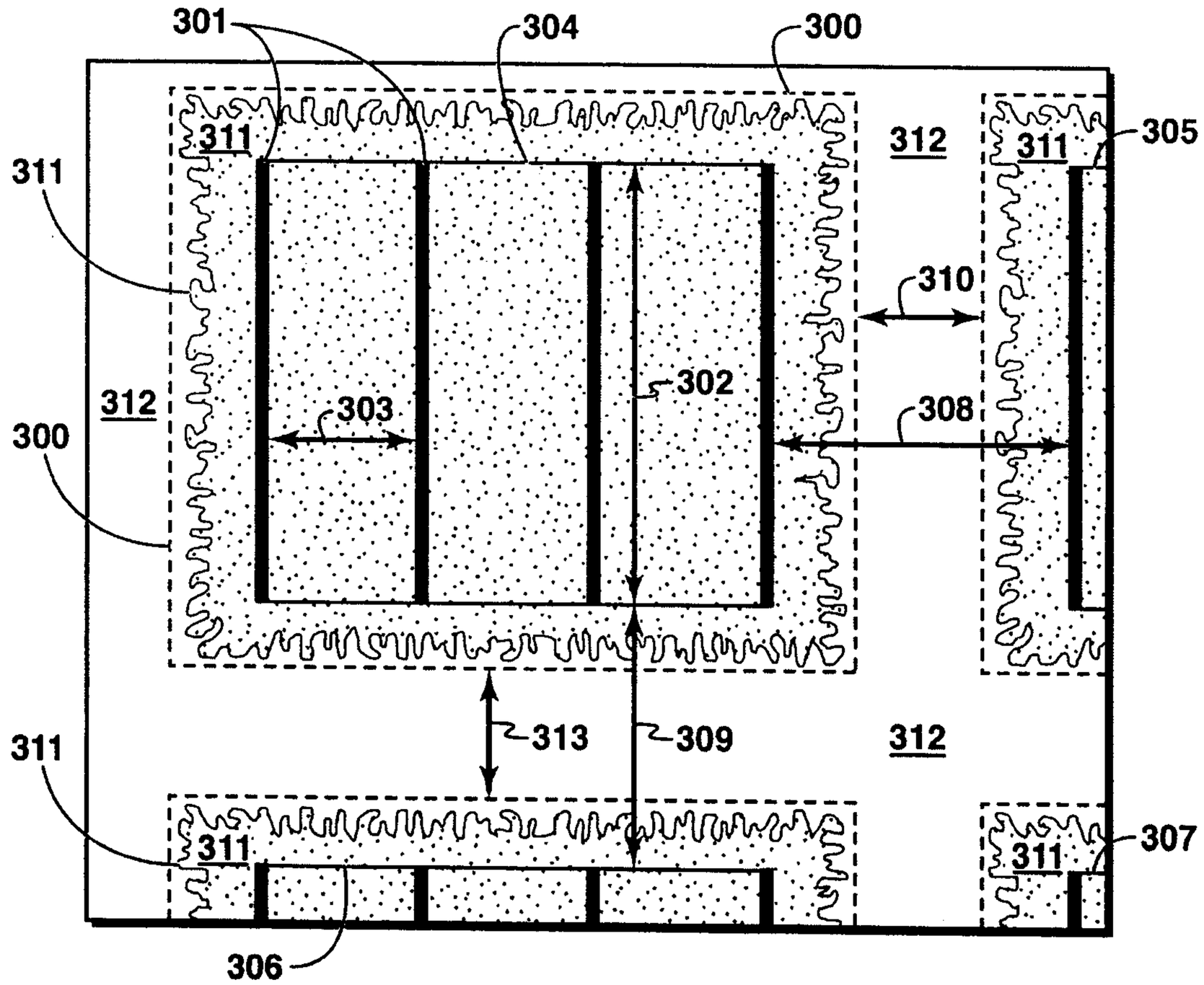

301
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307

FIG. 3

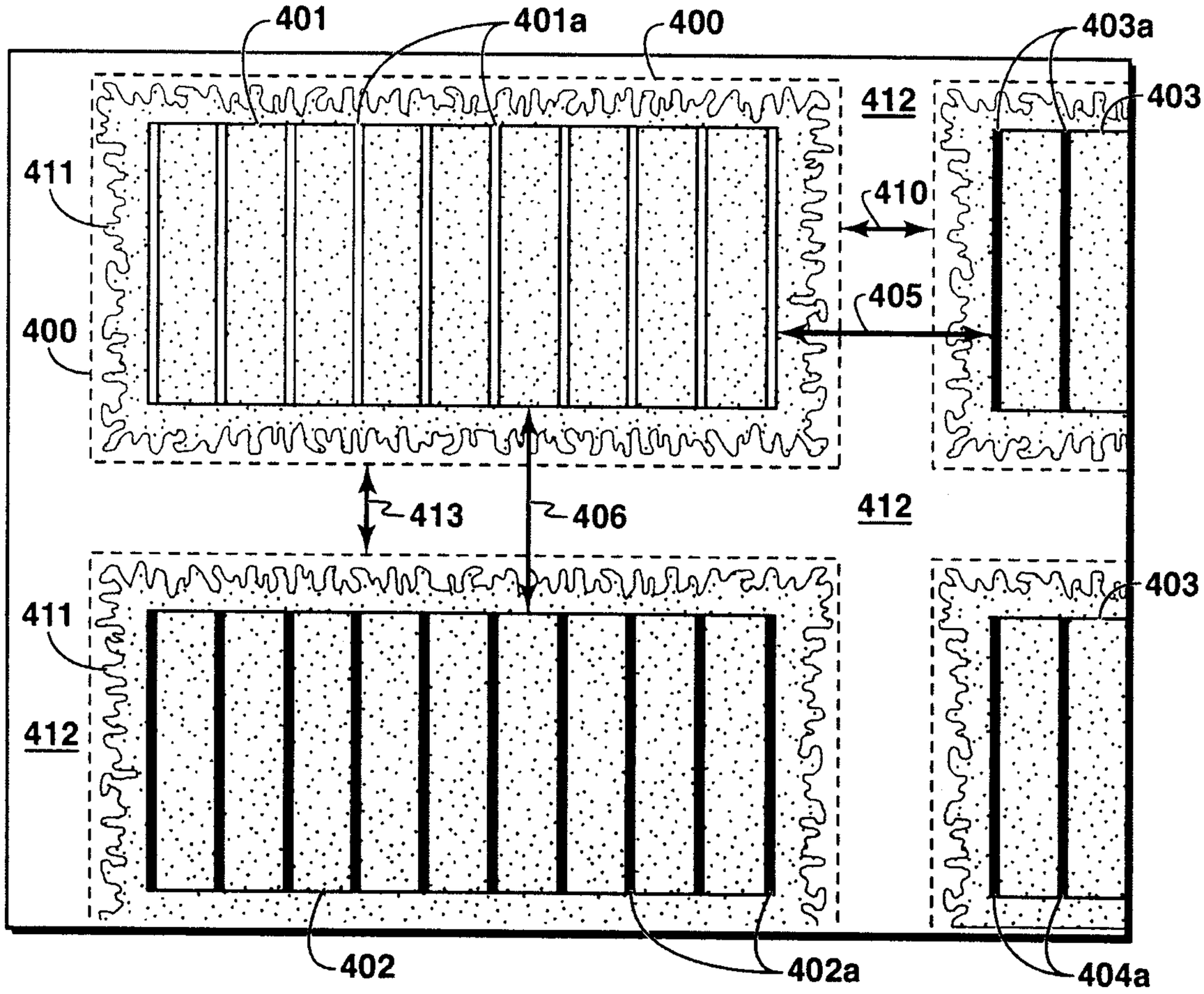

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403a
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404a

FIG. 4

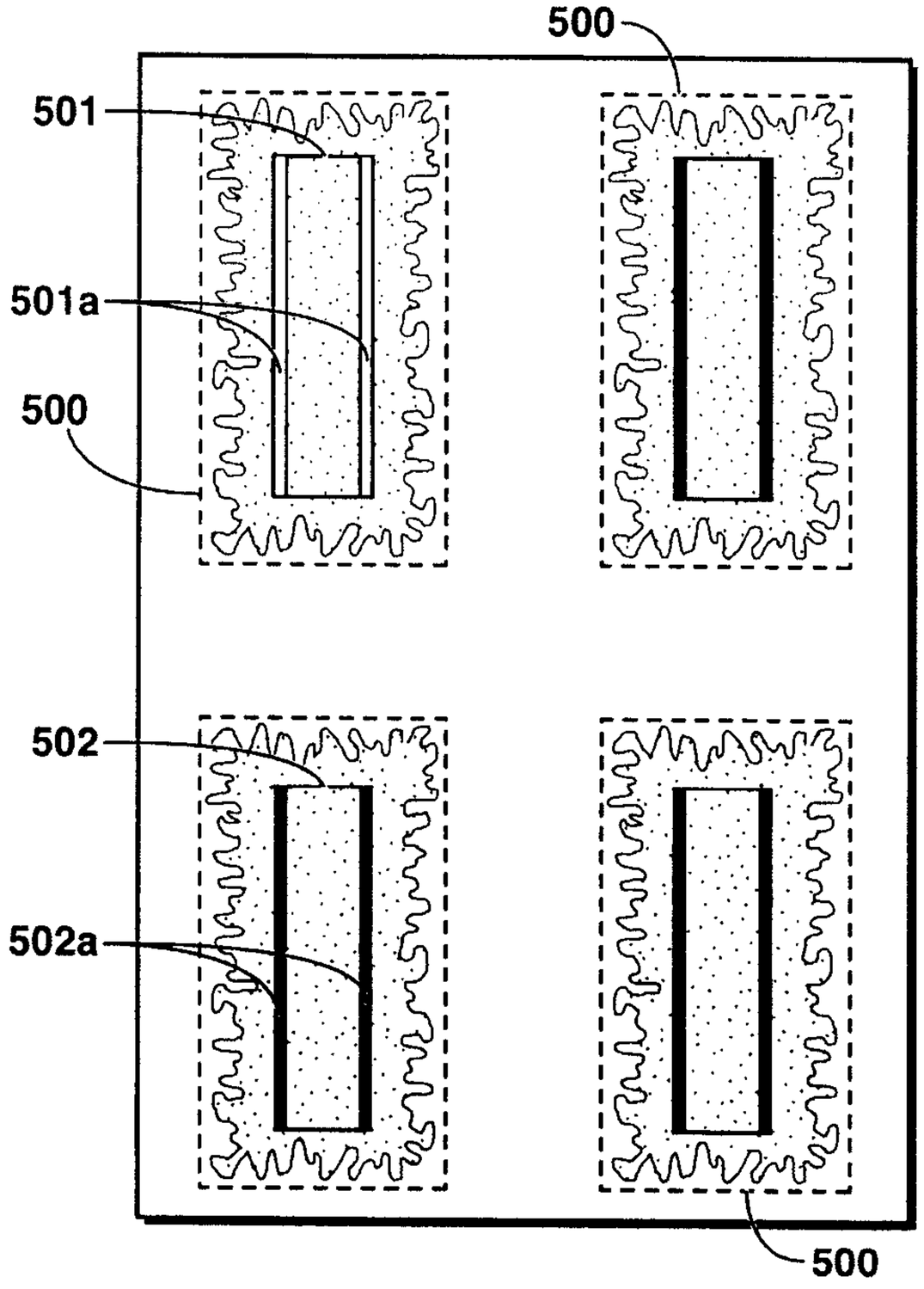


FIG. 5

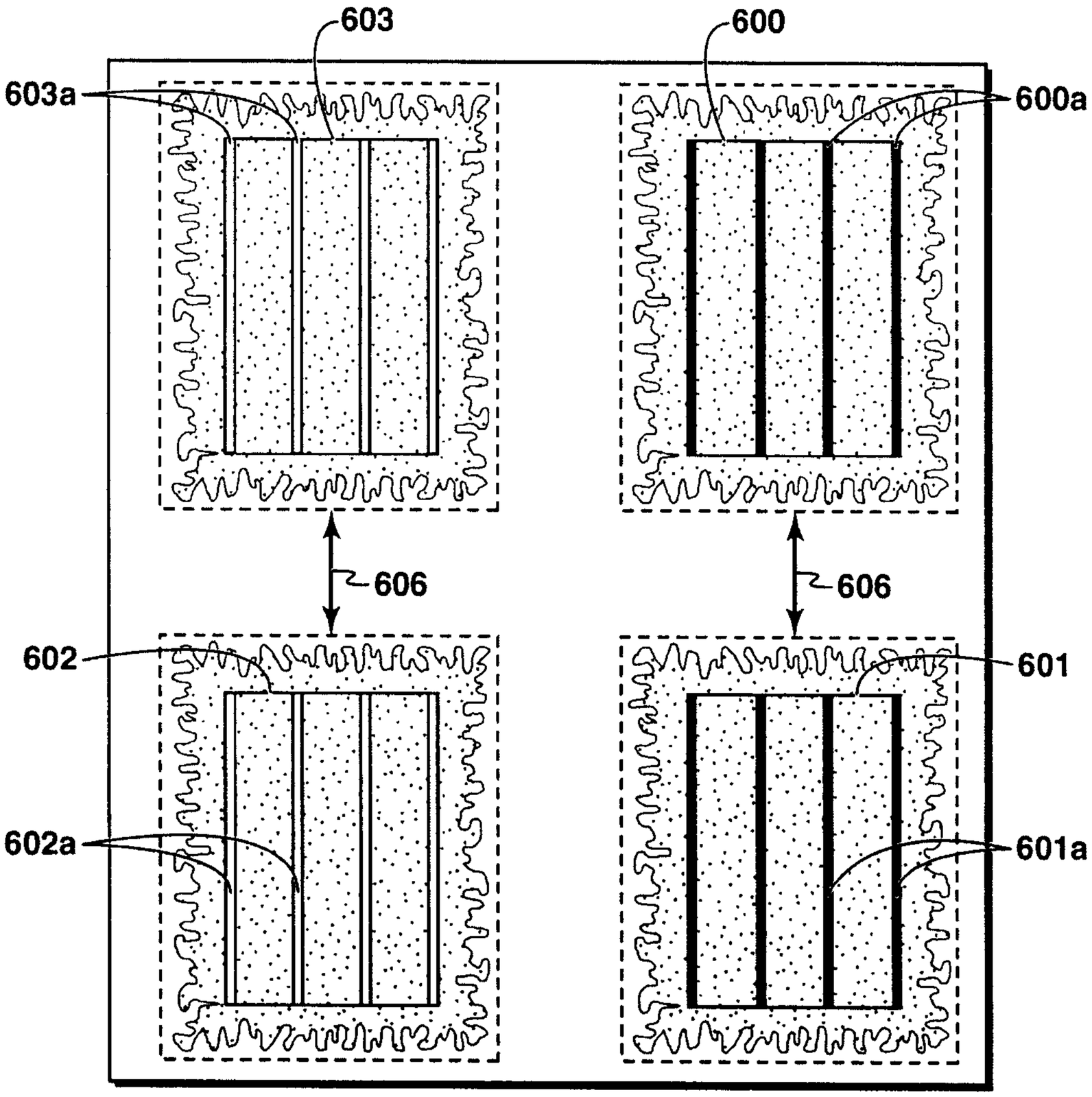


FIG. 6

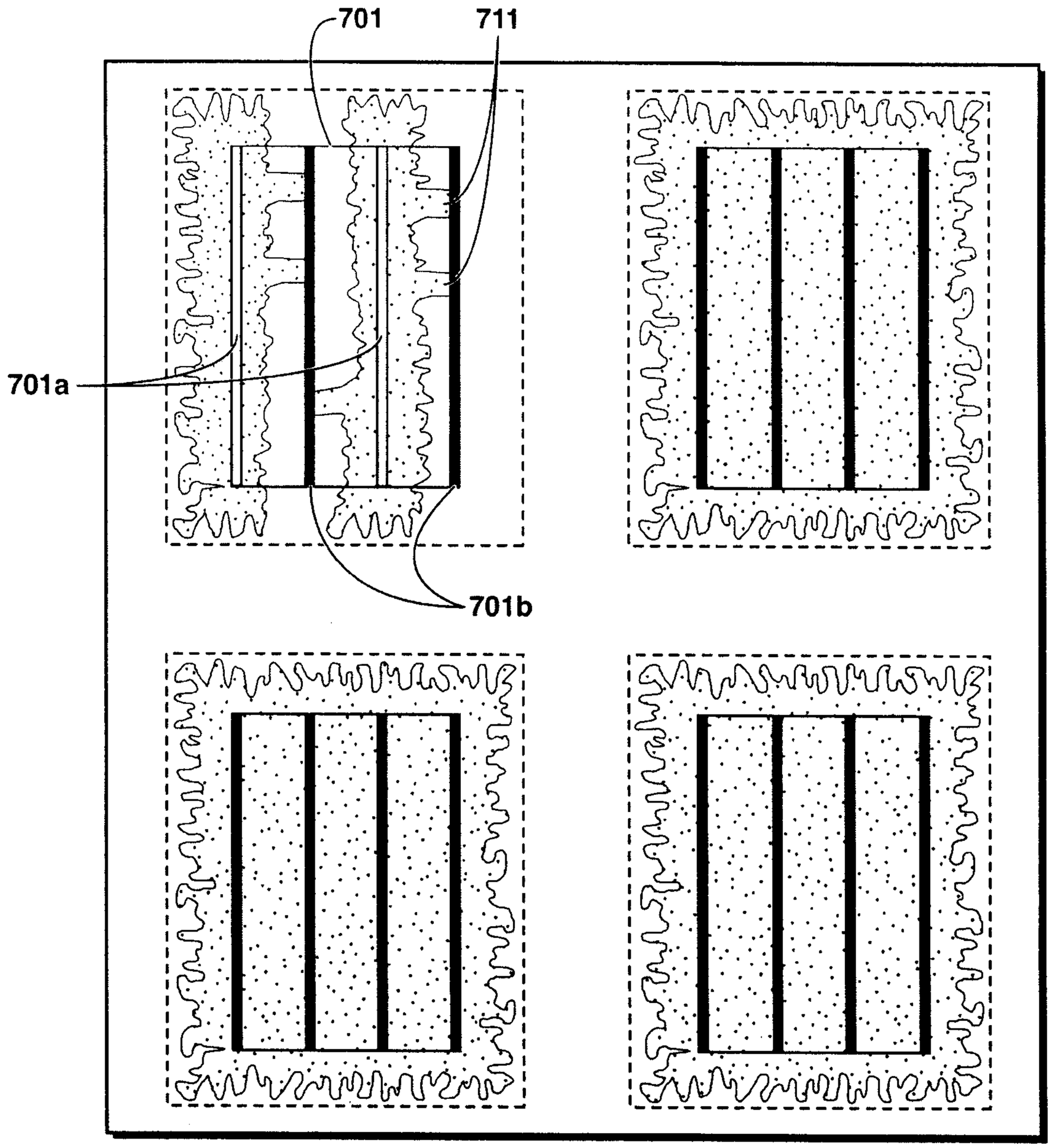


FIG. 7

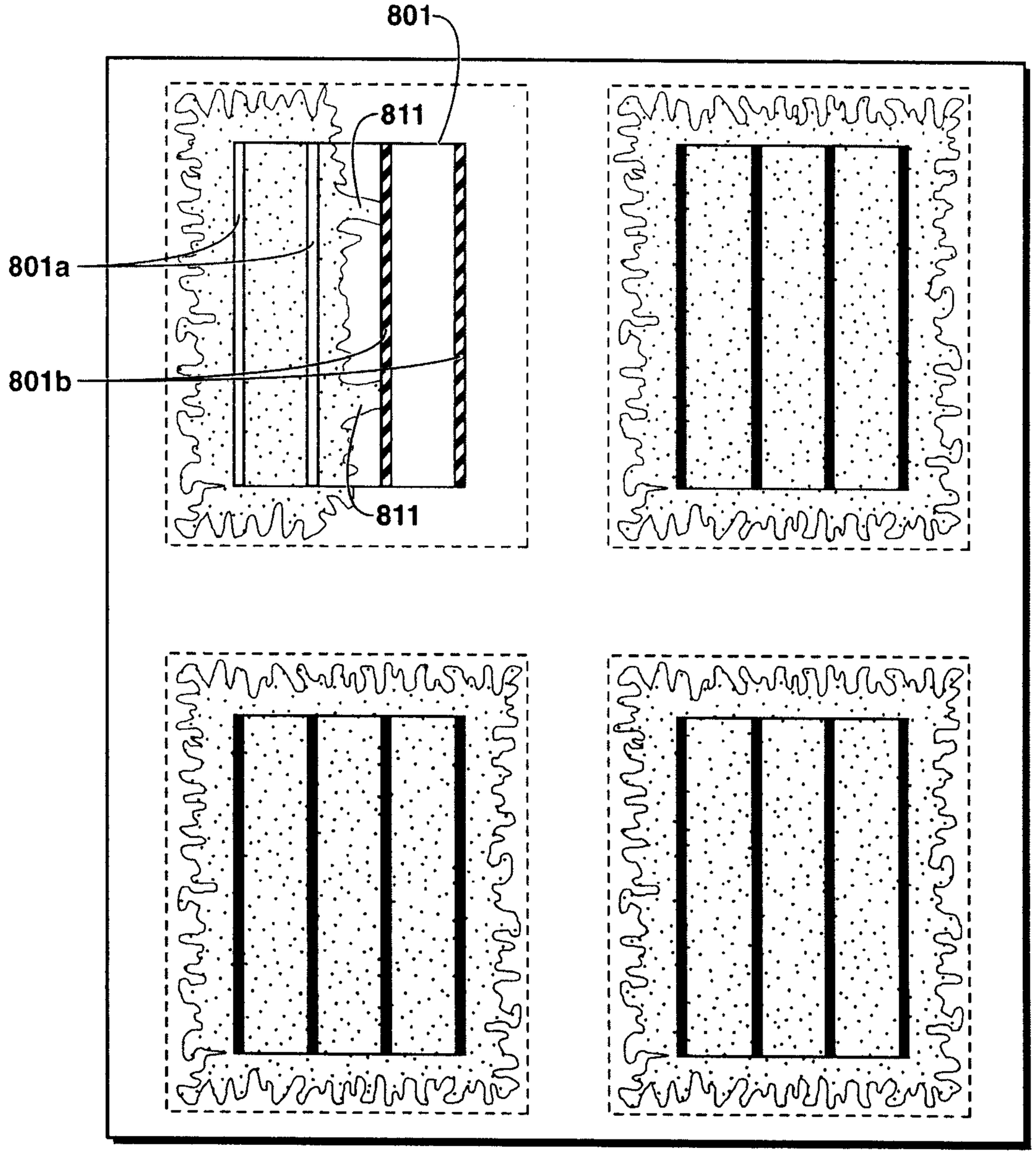


FIG. 8

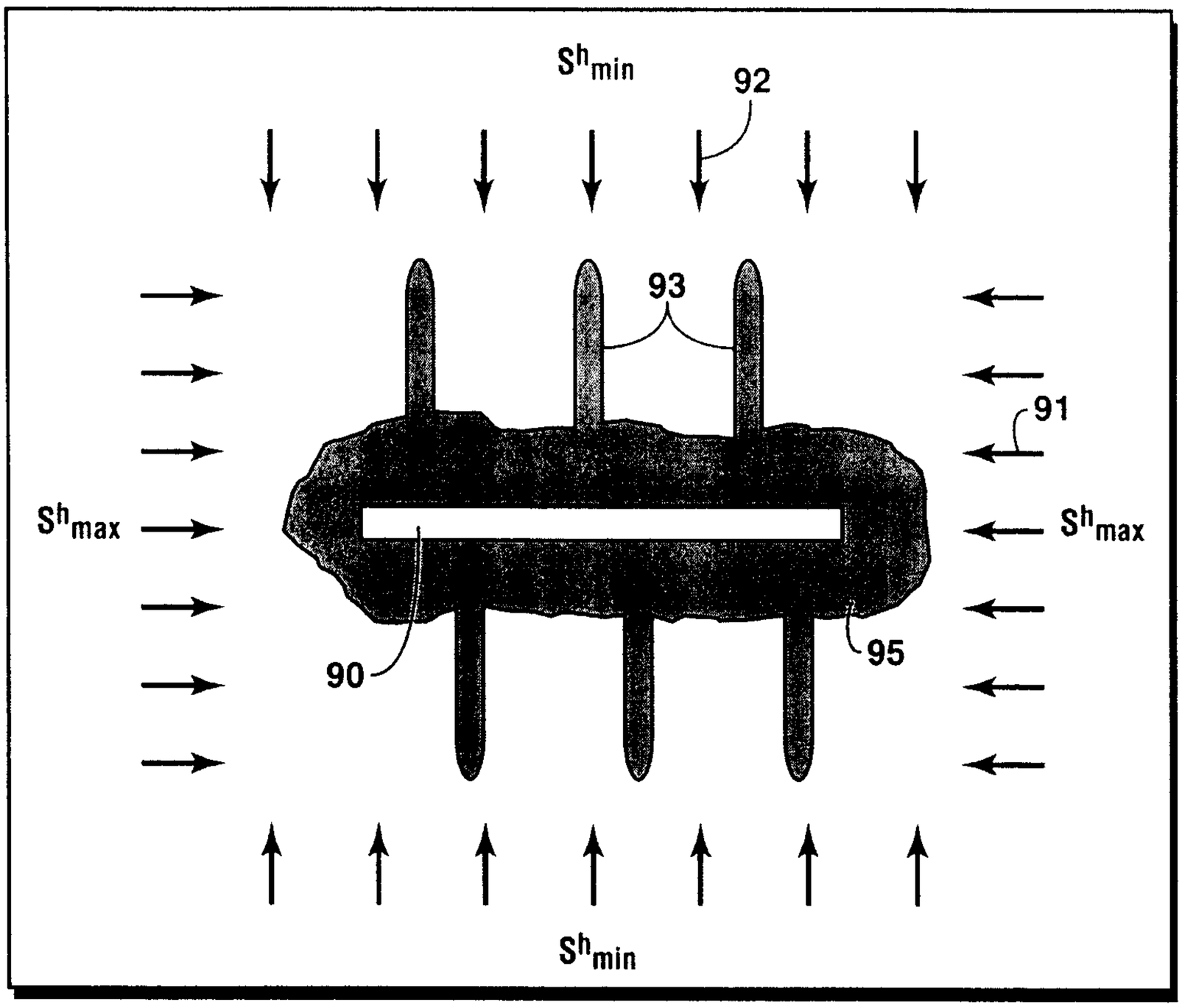

S^h_{min}
92
93
91
S^h_{max}
S^h_{max}
90
95
S^h_{min}

FIG. 9A

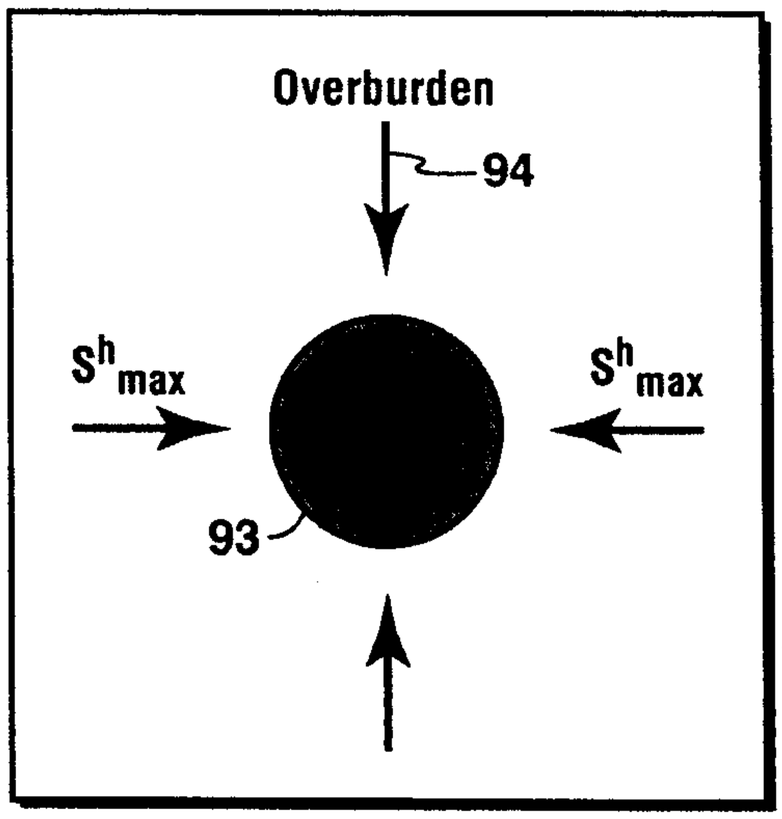

Overburden
94
S^h_{max}
S^h_{max}
93

FIG. 9B

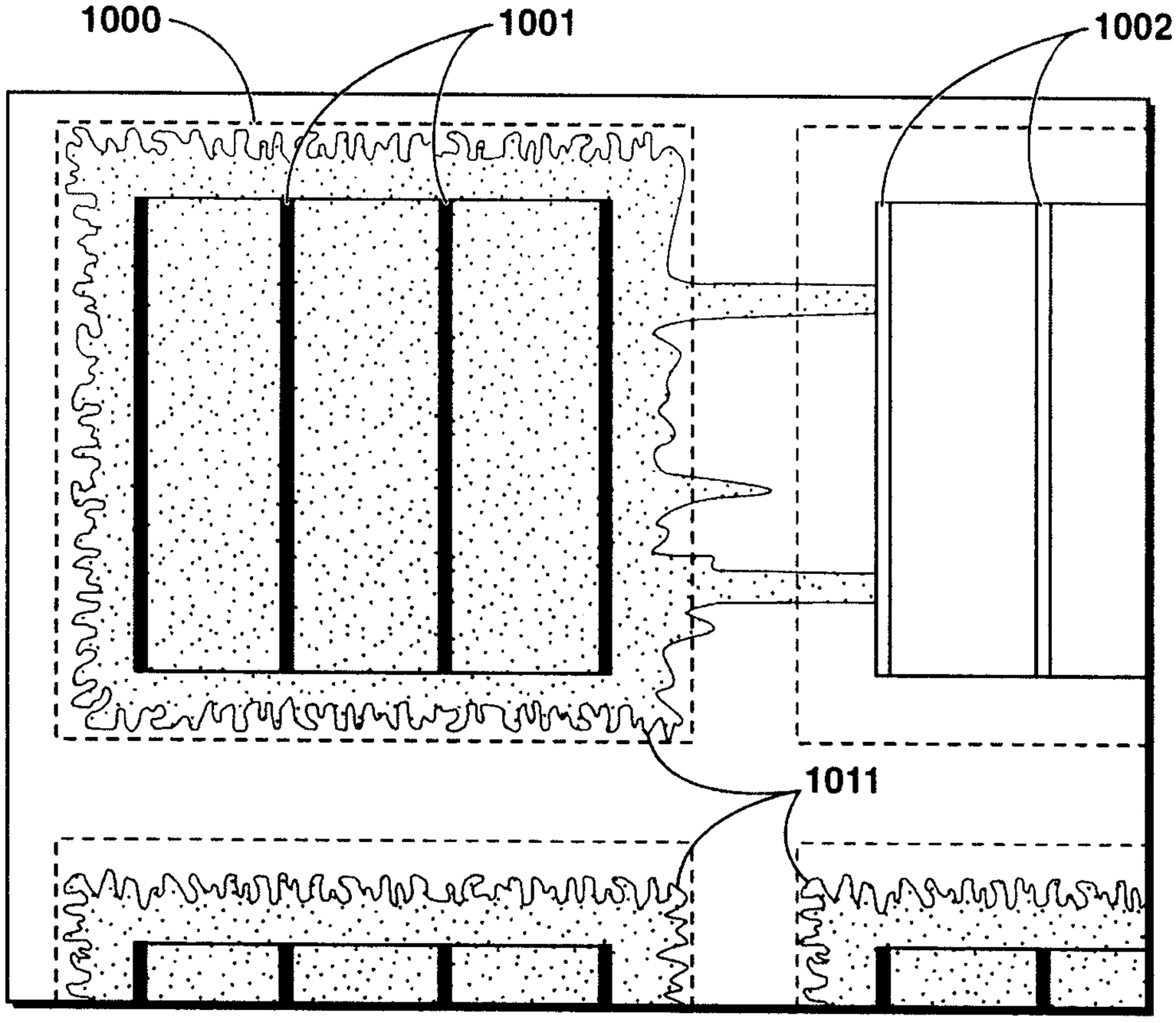


FIG. 10A

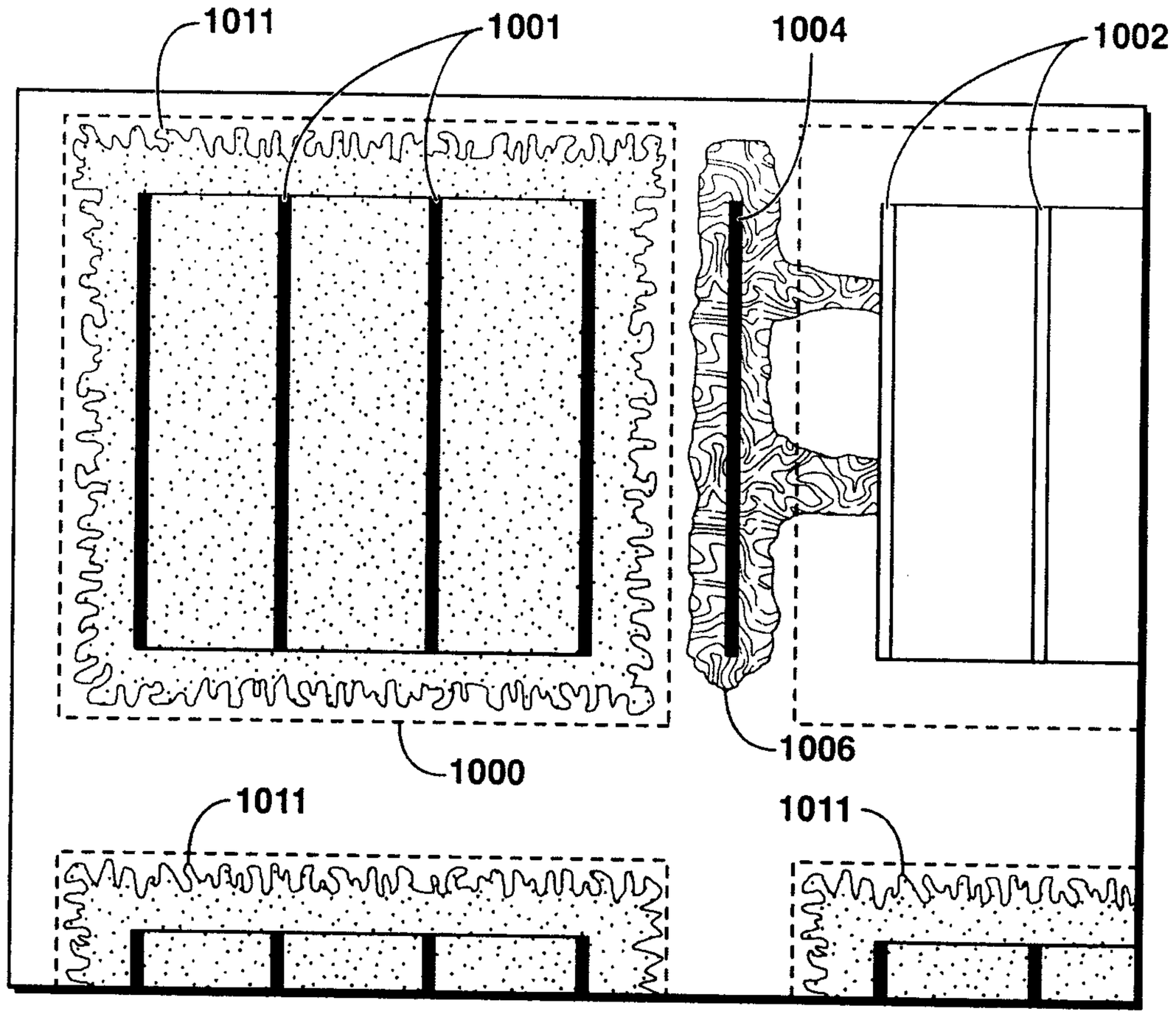
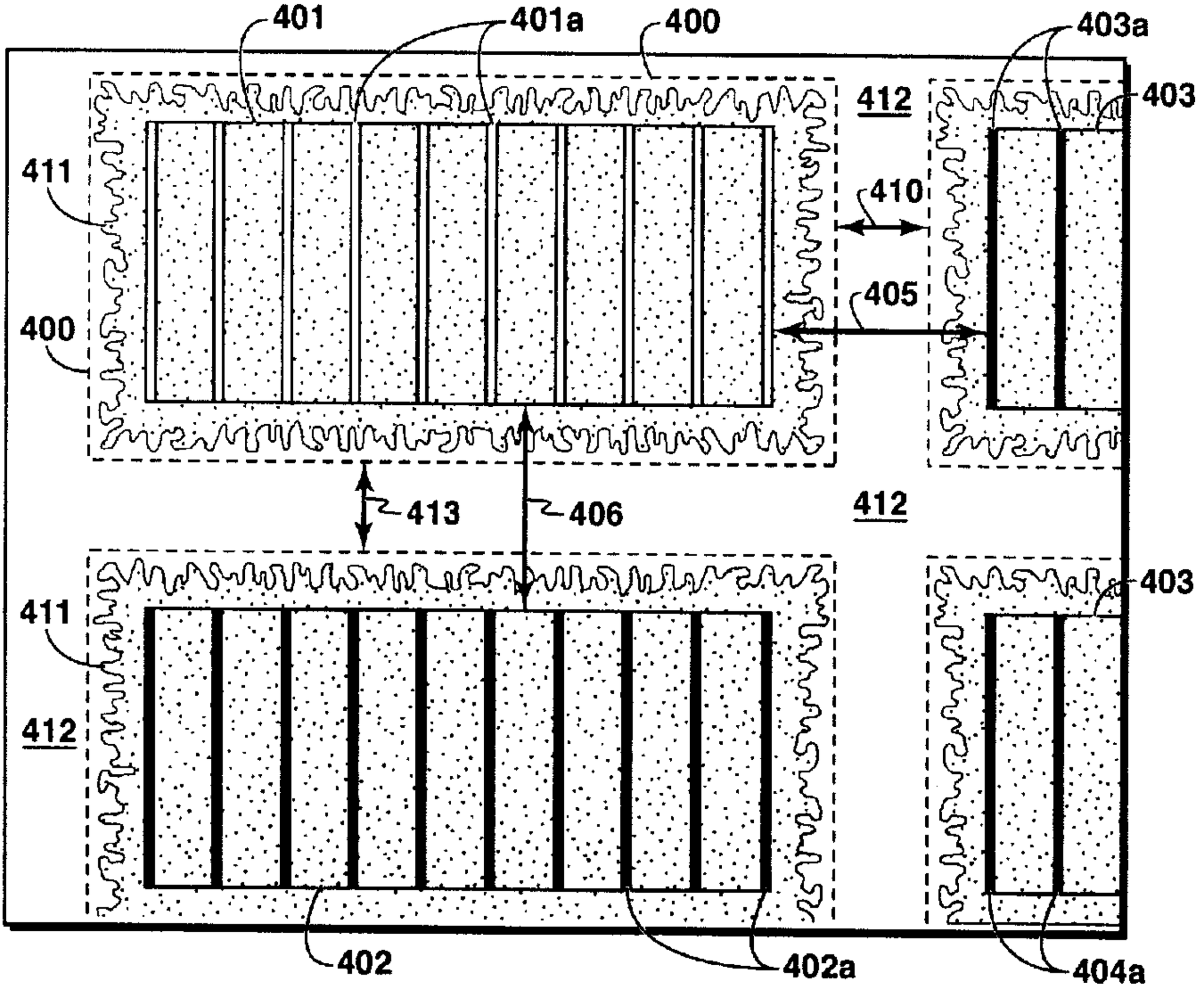


FIG. 10B


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