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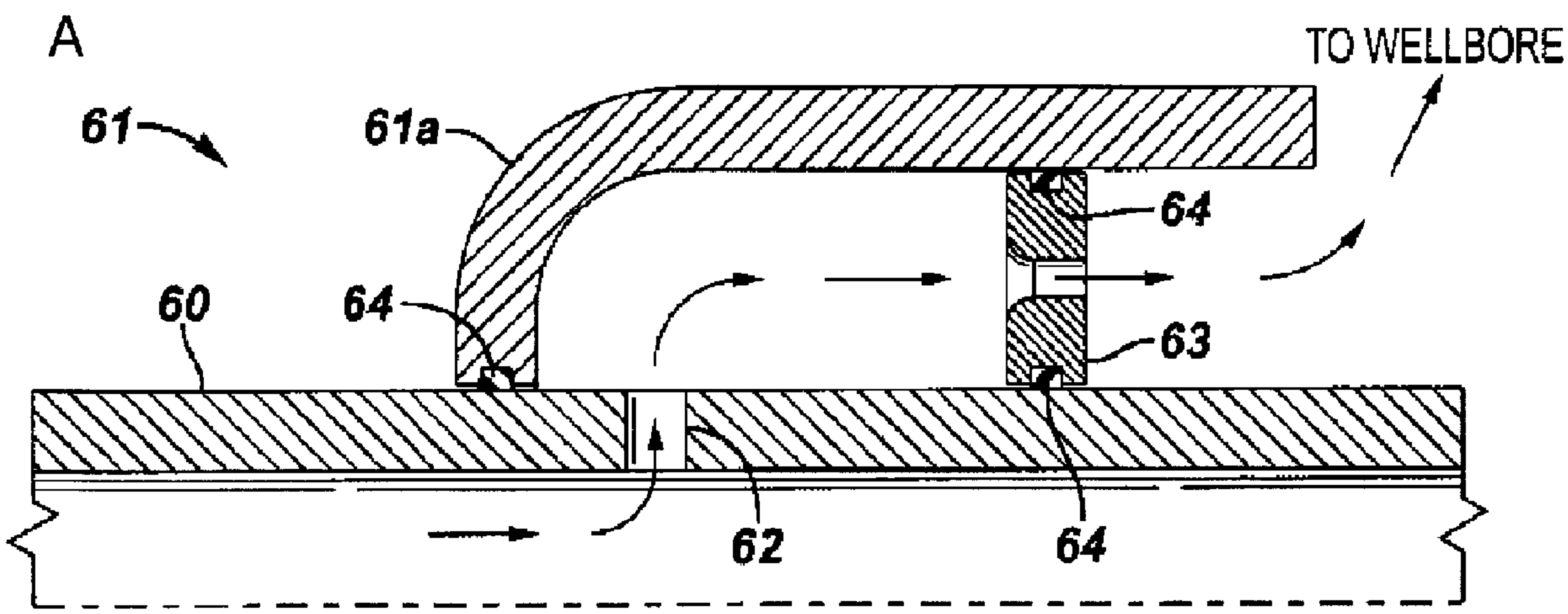
(54) Titre : CONFIGURATION DE PUITS SAGD
(54) Title: SAGD WELL CONFIGURATION



(57) Abrégé/Abstract:
Estimates of global total "liquid" hydrocarbon resources are dominated by structures known as oil sands or tar sands which represent approximately two-thirds of the total recoverable resources. This is despite that the Canadian Athabasca Oil Sands, which dominate these oil sand based recoverable oil reserves at 1.7 trillion barrels, are calculated at only a 10% recovery rate. However, irrespective of whether it is the 3.6 trillion barrels recoverable from the oil sands or the 1.75 trillion barrels from conventional oil reservoirs worldwide, it is evident that significant financial return and extension of the time oil as resource is available to the world arise from increasing the recoverable percentage of such resources. According to embodiments of the invention specific well pad arrays are employed to exploit the inherent properties of thermal well bores and adjust the evolution of the depletion chambers formed between the vertically spaced wells to increase the oil recovery efficiency and percentage, and to provide recovery in deeper reservoirs.

ABSTRACT

Estimates of global total "liquid" hydrocarbon resources are dominated by structures known as oil sands or tar sands which represent approximately two-thirds of the total recoverable resources. This is despite that the Canadian Athabasca Oil Sands, which dominate these oil sand based recoverable oil reserves at 1.7 trillion barrels, are calculated at only a 10% recovery rate. However, irrespective of whether it is the 3.6 trillion barrels recoverable from the oil sands or the 1.75 trillion barrels from conventional oil reservoirs worldwide, it is evident that significant financial return and extension of the time oil as resource is available to the world arise from increasing the recoverable percentage of such resources. According to embodiments of the invention specific well pad arrays are employed to exploit the inherent properties of thermal well bores and adjust the evolution of the depletion chambers formed between the vertically spaced wells to increase the oil recovery efficiency and percentage, and to provide recovery in deeper reservoirs.

SAGD WELL CONFIGURATION

FIELD OF THE INVENTION

[001] This invention relates to oil recovery and more specifically to exploiting the thermal properties of well bores in oil recovery.

BACKGROUND OF THE INVENTION

[002] Over the last two centuries, advances in technology have made our civilization completely oil, gas & coal dependent. Whilst gas and coal are primarily use for fuel oil is different in that immense varieties of products are and can be derived from it. A "brief" list of some of these products includes gasoline, diesel, fuel oil, propane, ethane, kerosene, liquid petroleum gas, lubricants, asphalt, bitumen, cosmetics, petroleum jelly, perfume, dish-washing liquids, ink, bubble gums, car tires, etc. In addition to these oil is the source of the starting materials for most plastics that form the basis of a massive number of consumer and industrial products.

[003] Table 1 below lists the top 15 consuming nations based upon 2008 data in terms of thousands of barrels (bbl) and thousand of cubic meters per day. Figure 1A presents the geographical distribution of consumption globally.

	Nation	(1000 bbl/day)	(1000 m^3/day)
1	United States	19,497.95	3,099.9
2	China	7,831.00	1,245.0
3	Japan	4,784.85	760.7
4	India	2,962.00	470.9
5	Russia	2,916.00	463.6
6	Germany	2,569.28	408.5
7	Brazil	2,485.00	395.1
8	Saudi Arabia	2,376.00	377.8
9	Canada	2,261.36	359.5
10	South Korea	2,174.91	345.8
11	Mexico	2,128.46	338.4
12	France	1,986.26	315.8
13	Iran (OPEC)	1,741.00	276.8
14	United Kingdom	1,709.66	271.8
15	Italy	1,639.01	260.6

Table 1: 2008 Oil Consumption for Top 15 Consuming Nations

[004] In terms of oil production Table 1B below lists the top 15 oil producing nations and the geographical distribution worldwide is shown in Figure 1B. Comparing Table 1A and Table 1B shows how some countries like Japan are essentially completely dependent on oil imports whilst most other countries such as the United States in the list whilst producing significantly are still massive importers. Very few countries, such as Saudi Arabia and Iran are net exporters of oil globally.

	Nation	(1000 bbl/day)	Market Share
1	Saudi Arabia	9,760	11.8%
2	Russia	9,934	12.0%
3	United States	9,141	11.1%
4	Iran (OPEC)	4,177	5.1%
5	China	3,996	4.8%
6	Canada	3,294	4.0%
7	Mexico	3,001	3.6%
8	UAE (OPEC)	2,795	3.4%
9	Kuwait (OPEC)	2,496	3.0%
10	Venezuela (OPEC)	2,471	3.0%
11	Norway	2,350	2.8%
12	Brazil	2,577	3.1%
13	Iraq (OPEC)	2,400	2.9%
14	Algeria (OPEC)	2,126	2.6%
15	Nigeria (OPEC)	2,211	2.7%

Table 2: Top 15 Oil Producing Nations

[005] In terms of oil reserves then these are dominated by a relatively small number of nations as shown below in Table 3 and in Figure 1C. With the exception of Canada the vast majority of these oil reserves are associated with conventional oil fields. Canadian reserves being dominated by Athabasca oil sands which are large deposits of bitumen, or extremely heavy crude oil, located in northeastern Alberta, Canada. The stated reserves of approximately 170,000 billion barrels is based upon only 10% of total actual reserves, these being those economically viable to recover in 2006.

	Nation	Reserves (1000 bbl)	Share
1	Saudi Arabia	264,600,000	19.00%
2	Canada	175,200,000	12.58%

3	Iran	137,600,000	9.88%
4	Iraq	115,000,000	8.26%
5	Kuwait	104,000,000	7.47%
6	United Arab Emirates	97,800,000	7.02%
7	Venezuela	97,770,000	7.02%
8	Russia	74,200,000	5.33%
9	Libya	47,000,000	3.38%
10	Nigeria	37,500,000	2.69%
11	Kazakhstan	30,000,000	2.15%
12	Qatar	25,410,000	1.82%
13	China	20,350,000	1.46%
14	United States	19,120,000	1.37%
15	Angola	13,500,000	0.97%

Table 3: Top 15 Oil Reserve Nations

[006] Therefore in the vast majority of wells are drilled into oil reservoirs to extract the crude oil. An oil well is created by drilling a hole 5 to 50 inches (127.0 mm to 914.4 mm) in diameter into the earth with a drilling rig that rotates a drill string with a bit attached. After the hole is drilled, sections of steel pipe (casing), slightly smaller in diameter than the borehole, are placed in the hole. Cement may be placed between the outside of the casing and the borehole to provide structural integrity and to isolate high pressure zones from each other and from the surface. With these zones safely isolated and the formation protected by the casing, the well can be drilled deeper, into potentially more unstable formations, with a smaller bit, and also cased with a smaller size casing. Typically wells have two to five sets of subsequently smaller hole sizes drilled inside one another, each cemented with casing.

[007] Oil recovery operations from conventional oil wells have been traditionally subdivided into three stages: primary, secondary, and tertiary. Primary production, the first stage of production, produces due to the natural drive mechanism existing in a reservoir. These "Natural lift" production methods that rely on the natural reservoir pressure to force the oil to the surface are usually sufficient for a while after reservoirs are first tapped. In some reservoirs, such as in the Middle East, the natural pressure is sufficient over a long time. The natural pressure in many reservoirs, however, eventually dissipates such that the oil must then be pumped out using “artificial lift” created by mechanical pumps powered by gas or electricity. Over time, these "primary" methods become less effective and "secondary" production methods may be used.

[008] The second stage of oil production, secondary recovery, is usually implemented after primary production has declined to unproductive levels, usually defined in economic return rather than absolute oil flow. Traditional secondary recovery processes are water flooding, pressure maintenance, and gas injection, although the term secondary recovery is now almost synonymous with water flooding. Tertiary recovery, the third stage of production, commonly referred to as enhanced oil recovery ("EOR") is implemented after water flooding. Tertiary processes use miscible and/or immiscible gases, polymers, chemicals, and thermal energy to displace additional oil after the secondary recovery process becomes uneconomical.

[009] Enhanced oil recovery processes can be classified into four overall categories: mobility control, chemical, miscible, and thermal.

- Mobility-control processes, as the name implies, are those based primarily on maintaining a favorable mobility ratio. Examples of mobility control processes are thickening of water with polymers and reducing gas mobility with foams.
- Chemical processes are those in which certain chemicals, such as surfactants or alkaline agents, are injected to utilize interfacial tension reduction, leading to improved displacement of oil.
- In miscible processes, the objective is to inject fluids that are directly miscible with the oil or that generate miscibility in the reservoir through composition alteration. The most popular form of a miscible process is the injection of carbon dioxide.
- Thermal processes rely on the injection of thermal energy or the in-situ generation of heat to improve oil recovery by reducing the viscosity of oil.

[0010] In the United States, primary production methods account for less than 40% of the oil produced on a daily basis, secondary methods account for about half, and tertiary recovery the remaining 10%.

[0011] Bituminous sands, colloquially known as oil sands or tar sands, are a type of unconventional petroleum deposit. The oil sands contain naturally occurring mixtures of sand, clay, water, and a dense and extremely viscous form of petroleum technically referred to as bitumen (or colloquially "tar" due to its similar appearance, odour, and colour). These oil sands reserves have only recently been considered as part of the world's oil reserves, as higher oil prices and new technology enable them to be profitably extracted and upgraded to usable products. They are often referred to as unconventional oil or crude bitumen, in order to distinguish the bitumen extracted from oil sands from the free-flowing hydrocarbon mixtures known as crude oil

[0012] Many countries in the world have large deposits of oil sands, including the United States, Russia, and various countries in the Middle East. However, the world's largest deposits occur in two countries: Canada and Venezuela, each of which has oil sand reserves approximately equal to the world's total reserves of conventional crude oil. As a result of the development of Canadian oil sands reserves, 44% of Canadian oil production in 2007 was from oil sands, with an additional 18% being heavy crude oil, while light oil and condensate had declined to 38% of the total.

[0013] Because growth of oil sands production has exceeded declines in conventional crude oil production, Canada has become the largest supplier of oil and refined products to the United States, ahead of Saudi Arabia and Mexico. Venezuelan production is also very large, but due to political problems within its national oil company, estimates of its production data are not reliable. Outside analysts believe Venezuela's oil production has declined in recent years, though there is much debate on whether this decline is depletion-related or not.

[0014] However, irrespective of such issues the oil sands may represent as much as two-thirds of the world's total "liquid" hydrocarbon resource, with at least 1.7 trillion barrels ($270x10^9 m^3$) in the Canadian Athabasca Oil Sands alone assuming even only a 10% recovery rate. In October 2009, the United States Geological Service updated the Orinoco oil sands (Venezuela) mean estimated recoverable value to 513 billion barrels ($81.6x10^9 m^3$) making it "one of the world's largest recoverable" oil deposits. Overall the Canadian and Venezuelan deposits contain about 3.6 trillion barrels ($570x10^9 m^3$) of recoverable oil, compared to 1.75 trillion barrels ($280x10^9 m^3$) of conventional oil worldwide, most of it in Saudi Arabia and other Middle-Eastern countries.

[0015] Because extra-heavy oil and bitumen flow very slowly, if at all, toward producing wells under normal reservoir conditions, the oil sands must be extracted by strip mining and processed or the oil made to flow into wells by in situ techniques, which reduce the viscosity. Such in situ techniques include injecting steam, solvents, heating the deposit, and/or injecting hot air into the oil sands. These processes can use more water and require larger amounts of energy than conventional oil extraction, although many conventional oil fields also require large amounts of water and energy to achieve good rates of production. Accordingly, these oil sand deposits were previously considered unviable until the 1990s when substantial investment was made into them as oil prices increased to the point of economic viability as well as concerns over security of supply, long term global supply, etc.

[0016] Amongst the reasons for more water and energy of oil sand recovery apart from the initial energy expenditure in reducing viscosity is that the heavy crude feedstock recovered requires pre-processing before it is fit for conventional oil refineries. This pre-processing is called 'upgrading', the key components of which are:

1. removal of water, sand, physical waste, and lighter products;
2. catalytic purification by hydrodemetallisation (HDM), hydrodesulfurization (HDS) and hydrodenitrogenation (HDN); and
3. hydrogenation through carbon rejection or catalytic hydrocracking (HCR).

[0017] As carbon rejection is very inefficient and wasteful in most cases, catalytic hydrocracking is preferred in most cases. All these processes take large amounts of energy and water, while emitting more carbon dioxide than conventional oil.

[0018] Amongst the category of known secondary production techniques the injection of a fluid (gas or liquid) into a formation through a vertical or horizontal injection well to drive hydrocarbons out through a vertical or horizontal production well. Steam is a particular fluid that has been used. Solvents and other fluids (e.g., water, carbon dioxide, nitrogen, propane and methane) have also been used. These fluids typically have been used in either a continuous injection and production process or a cyclic injection and production process. The injected fluid can provide a driving force to push hydrocarbons through the formation, or the injected fluid can enhance the mobility of the hydrocarbons (e.g., by reducing viscosity via heating) thereby facilitating the release of the more mobile hydrocarbons to a production location. Recent developments using horizontal wells have focused on utilizing gravity drainage to achieve better results. At some point in a process using separate injection and production wells, the injected fluid may migrate through the formation from the injection well to the production well thereby “contaminating” the oil recovered in the sense that additional processing must be applied before the oil can be pre-processed for compatibility with convention oil refineries working with the light oil recovered from conventional oil well approaches..

[0019] Therefore, a secondary production technique injecting a selected fluid and for producing hydrocarbons should maximize production of the hydrocarbons with a minimum production of the injected fluid, see for example U.S. Patent 4,368,781. Accordingly, the early breakthrough of the injected fluid from an injection well to a production well and an excessive rate of production of the injected fluid is not desirable. See for example Joshi et al in “Laboratory Studies of Thermally Aided Gravity Drainage Using Horizontal Wells" (AOSTRA J. of Research, pages 11-19, vol. 2, no. 1, 1985). It has also been disclosed that optimum production from a horizontal production well is limited by the critical velocity of the fluid through the formation. This being thought necessary to avoid so-called "fingering" of the injected fluid through the formation, see U.S. Patent 4,653,583, although in US Patent 4,257,650 it is disclosed that "fingering" is not critical in radial horizontal well production systems.

[0020] The foregoing disclosures have been within contexts referring to various spatial arrangements of injection and production wells, which can be classified as follows: vertical injection wells with vertical production wells, horizontal injection wells with horizontal production wells, and combinations of horizontal and vertical injection and production wells. Whilst embodiments of the invention described below can be employed in all of these configurations the dominant production methodology today relates to the methods using separate, discrete horizontal injection and production wells. This arises due to the geological features of oil sands wherein the oil bearing are typically thin but distributed over a large area. Amongst the earliest prior art for horizontal injection wells with horizontal production well arrangements are U.S. Patents 4,700,779; 4,385,662; and 4,510,997.

[0021] Within the initial deployments the parallel horizontal injection and production wells vertically were aligned a few meters apart as disclosed in the aforementioned article by Joshi. Associated articles include:

- Butler et al in "The gravity drainage of steam-heated heavy oil to parallel horizontal wells" (J. of Canadian Petroleum Technology, pages 90-96, 1981);

- Butler in "Rise of interfering steam chambers" (J. of Canadian Petroleum Technology, pages 70-75, vol. 26, no. 3, 1986);
- Ferguson et al in "Steam-assisted gravity drainage model incorporating energy recovery from a cooling steam chamber" (J. of Canadian Petroleum Technology, pages 75-83, vol. 27, no. 5, 1988);
- Butler et al in "Theoretical Estimation of Breakthrough Time and Instantaneous Shape of Steam Front During Vertical Steamflooding," (AOSTRA J. of Research, pages 359-381, vol. 5, no. 4, 1989); and
- Griffin et al in "Laboratory Studies of the Steam-Assisted Gravity Drainage Process," (5th Advances in Petroleum Recovery & Upgrading Technology Conference, June 1984, Calgary, Alberta, Canada (session 1, paper 1).

[0022] Vertically aligned horizontal wells are also disclosed in U.S. Patents 4,577,691; 4,633,948; and 4,834,179. Staggered horizontal injection and production wells, wherein the injection and production wells are both laterally and vertically spaced from each other, are disclosed in Joshi in "A Review of Thermal Oil Recovery Using Horizontal Wells" (In Situ, Vol. 11, pp211-259, 1987); Change et al in "Performance of Horizontal-Vertical Well Combinations for Steamflooding Bottom Water Formations," (CIM/SPE 90-86, Petroleum Society of CIM/Society of Petroleum Engineers) as well as US Patents 4,598,770 and 4,522,260.

[0023] Amongst other patents addressing such recovery processes are US Patents 5,456,315' 5,860,475; 6,158,510; 6,257,334; 7,069,990; 6,988,549; 7,556,099; 7,591,311 and US Patent Applications 2006/0,207,799; 2008/0,073,079; 2010/0,163,229, 2009/0,020,335; 2008/0,087,422; 2009/0,255,661; 2009/0,260,878; 2009/0,260,878; 2008/0,289,822; 2009/0,044,940; 2009/0,288,827; and 2010/0,326,656. Additionally there are literally hundreds of patents relating to the steam generating apparatus, drilling techniques, sensors, etc associated with such production techniques as well as those addressing combustion assisted gravity drainage etc.

[0024] The first commercially applied process was cyclic steam stimulation, commonly referred to as "huff and puff", wherein steam is injected into the formation, commonly at above fracture pressure, through a usually vertical well for a period of time. The well is then shut in for several months, referred to as the "soak" period, before being re-opened to produce heated oil and steam condensate until the production rate declines. The entire cycle is then repeated and during the course of the process an expanding "steam chamber" is gradually developed where the oil has drained from the void spaces of the chamber, been produced through the well during the production phase, and is replaced with steam. Newly injected steam moves through the void spaces of the hot chamber to its boundary, to supply heat to the cold oil at the boundary.

[0025] However, there are problems associated with the cyclic process including:

- fracturing tends to occur vertically along a direction dictated by the tectonic regime present in the formation;
- steam tends to preferentially move through the fractures and heat outwardly therefrom so that developed chamber tends to be relatively narrow;
- low efficiency with respect to steam utilization; and
- there are large bodies of unheated oil left in the zone extending between adjacent wells with their linearly extending steam chambers.

[0026] Accordingly, the cyclic process relatively low oil recovery. As such, as described in Canadian Patent 1,304,287, a continuous steam process has become dominant approach, known as steam-assisted gravity drainage ("SAGD"). The approach exploiting:

- a pair of coextensive horizontal wells, one above the other, located close to the base of the formation;
- the formation between the wells is heated by circulating steam through each of the wells at the same time to create a pair of "hot fingers";
- when the oil is sufficiently heated so that it may be displaced or driven from one well to the other, fluid communication between the wells is established and steam circulation through the wells is terminated;
- steam injection below the fracture pressure is initiated through the upper well and the lower well opened to produce draining liquid; and
- the production well is throttled to maintain steam trap conditions and to keep the temperature of the produced liquid at about 6-10° C below the saturation steam temperature at the production well.

[0027] This ensures a short column of liquid is maintained over the production well, thereby preventing steam from short-circuiting into the production well. As the steam is injected, it rises and contacts cold oil immediately above the upper injection well. The steam gives up heat and condenses; the oil absorbs heat and becomes mobile as its viscosity is reduced. The condensate and heated oil drain downwardly under the influence of gravity. The heat exchange occurs at the surface of an upwardly enlarging steam chamber extending up from the wells. This chamber being constituted of depleted, porous, permeable sand from which the oil has largely drained and been replaced by steam.

[0028] The steam chamber continues to expand upwardly and laterally until it contacts the overlying impermeable overburden and has an essentially triangular cross-section. If two laterally spaced pairs of wells undergoing SAGD are provided, their steam chambers grow laterally until they contact high in the reservoir. At this stage, further steam injection is terminated and production declines until the wells are abandoned. The SAGD process is characterized by several advantages, including relatively low pressure injection so that fracturing is not likely to occur, steam trap control minimizes short-circuiting of steam into the production well, and the SAGD steam chambers are broader than those developed by the cyclic process.

[0029] As a result oil recovery is generally better and with reduced energy consumption and emissions of greenhouse gases. However, there are still limitations with the SAGD process which need addressing. These include the need to more quickly achieve production from the SAGD wells, the need to completely and evenly heat the formation between the vertically spaced wells to increase the immediate and overall oil recovery percentage, to reduce the temperature of the produced emulsion at the point of production in the heel of the producer and thereby make mechanical pumping operation more efficient; and provide efficient SAGD operations over deeper oil sand formations.

[0030] In SAGD the velocity of bitumen falling through a column of porous media having equal pressures at top and bottom can be calculated from Darcy's Law, see Equation 1.

$$U_O^q = \frac{k_O P_O g_O}{\mu_O} \qquad (1)$$

where k_O is the effective permeability to bitumen and μ_O is the viscosity of the bitumen. For

Athabasca bitumen at about 200° C and using 5 as the value Darcy's effective permeability, the resulting velocity will be about 40 cm/day. Extending this to include a pressure differential then the equation for the flow velocity becomes that given by Equation 2.

$$U_O^+ = \frac{k_O P_O g}{\mu_O} + \frac{k_O \Delta P}{\mu_O L}$$

where ΔP is the pressure differential between the two well bores and L is the interwell well bore separation. For a typical interwell spacing this results in the value given in Table 1 below.

ΔP (psia)	$k_O \Delta / \mu_O L$ (cm/day)	$k_O P_O g / \mu_O = U_O q$ (cm/day)	U_O^+ (cm/day)	$U_O^+ / U_O g$
0.00	0.000	39.4	39.4	1.00
0.01	0.046	39.4	39.5	1.00
0.10	0.427	39.4	39.9	1.01
1.00	4.410	39.4	43.8	1.11
10.00	44.200	39.4	83.6	2.12
50.00	220.8	39.4	260.0	6.60

Table 1: Increased Bitumen Velocity under Pressure Differential

[0031] It is evident from the data presented in Table 1 that a more efficient and even heating of the zone between the wells pairs will aid in initial start up as well as overall performance of both the injector well bore and the producer well bore. Considering the Athabasca oil sands about 20 percent of the reserves are recoverable by surface mining where the overburden is less than 75 m (250 feet). It is the remaining 80 percent of the oil sands that are buried at a depth of greater than 75 m where SAGD and other in-situ technologies apply.

[0032] Accordingly, the inventor has established a beneficially well pad array design that may be exploited to advance production from SAGD wells by increasing the total heated area between vertically spaced wells and provide SAGD operating over deeper oil sand formations. All of the prior art relating to SAGD suggests that at least one injection well be positioned above at least on production well so that the injected fluids in the upper well can flow by gravity to the lower production well.

[0033] These horizontal SAGD well pairs generally extend for a substantial horizontal distance into the reservoir, upwards of 800 meters is not uncommon for the length of a SAGD well. This well arrangement and process creates a number of problems as the SAGD well pair is generally vertically spaced about 5-6 meters apart so that fluid communication can be established in a relatively short time frame, generally in 3-6 months. Very hot steam with a temperature of 300 degrees Celsius is injected into the formation to heat the immobile oil. The well pad arrangement is such that both the injector wells and the producer wells are drilled and completed from the same pad, with one well positioned above the other. It is desirable to drill as many well pairs as possible from a single well pad for economical reasons so the ancillary injection and production equipment that is required can be easily tied into the completed wells.

[0034] The current SAGD well pair array results in extremely hot steam, gases or fluids be injected into the injection well which is located almost immediately above the production well and then for the production well to produce the heated emulsion. Anyone skilled in the art can contemplate that over the length of the injection well, the point of injection, the heel, the heel will always be the hottest point in the well bore and conversely the tip or end of the well, the toe of the injection well, will be the coolest point of the well bore. Similarly, the same holds true for the production well as the heated fluid must flow to the production point of the well, which is also located in the heel of the well. So in both cases the heel is the hottest point in the well bores and the toe is the coolest. This creates a myriad of problems as it is desirable to heat the entire injection well bore evenly without creating hot spots in either well.

[0035] SAGD is a continuous process that requires injection and production to occur simultaneously so while the very hot fluid is being injected approximate to heel of the production well, the production well must produce the very hot emulsion that is draining into the production well bore and accumulating at the heel of the production well bore. This creates a very hot zone around both well bore heels which prevents the desired result of even heating of the entire injection well bore while at the same time maintaining a very hot zone at the heel of the production well bore which makes it very difficult for mechanical pumping operations to work effectively due to the extreme heat of both the emulsion and the entire zone around both well bore heels. Ideally, it would be desirable to provide for a well pair arrangement that would better take advantage of the inherent thermal properties of both the injection well and the production well.

SUMMARY OF THE INVENTION

[0036] It is the object of this invention is to mitigate the issues associated with the production of the heated emulsions by arranging the well pair array so that the well pairs are still easily positioned at the appropriate vertical separations as dictated by the reservoir conditions, and allowing for the completions and tie ins of all wells to the central surface production facility without placing the heel of the injection well above the heel of the production well. This can be done quite simply by drilling injection wells and production wells from the same well pads but in opposite directions to each other. For example at well pad number one the injectors may run south in the reservoir and the producers would then run north. These in fact would not be well pairs until the same drilling operations occurred at well pads number two and three, where, for better clarity all injectors would run south from each well pad and all producers would run north from each well pad. The end result is that each becomes a well pair but they are now opposingly aligned with the heel of one positioned over the toe of the other. Conversely, and as a preferred embodiment, each well pad would contain only producer wells and tie ins and injector wells and tie ins.

[0037] This could be done modularly so that each well pad is set up for each single operation. In this embodiment in one area of the reservoir one would have the producer module which would be linked to all the producers drilled from that well pad. On an opposing area of the reservoir would be the injector well module which would be linked to all the injector wells drilled from that well pad. This arrangement would facilitate tie ins to the surface facility and reduce CAPEX costs due to the easily repeatable modular set ups. If one were to drill in multiple directions from a producer well pad module then one would require at least one injector well pad module per each production well drilled direction so as to mate up each producer well with a corresponding injector well.

[0038] This array creates beneficial results in that now the heat of the injection which is greatest at the heel of the injector, is now located proximate to the coldest point of the producer, the toe of the producer, so that thermally the hottest point of the array is now located above the coldest point of the producer. Once production has started and the heated emulsion is now collecting at the heel of the producer the producer heel becomes its hottest point which will dramatically aid in the heating of the coldest point of the injector well bore, the toe. The end result is more efficient use of the thermal properties of both well bores.

[0039] Another benefit to the above noted well arrangement is that now the heel of the producer will remain much cooler without having the heel of the injector directly above it, which should facilitate improved mechanical pumping operations due to the cooler environment created by the arrangement.

[0040] In accordance with an embodiment of the invention there is provided a method comprising:

drilling a first well within an oil bearing structure from one well pad;

drilling a second well within the oil bearing structure in predetermined relationship with the first well from a second well pad;

according to a schedule injecting a heated mobilizing fluid into at least one of the first or second wells under first predetermined conditions;

operating the wells as a SAGD well pair so that the lower of the two wells extracts oil from the oil bearing structure.

[0041] In accordance with an embodiment of the invention there is provided

drilling a first well within an oil bearing structure from one well pad;

drilling a second well within the oil bearing structure so that the heel of the second well is located proximate to the toe of the first well from a second well pad;

according to a schedule injecting a heated mobilizing fluid into the first and second wells under first predetermined conditions;

operating the wells as a SAGD well pair so that the lower of the two wells extracts oil from the oil bearing structure.

[0042] 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

[0043] Embodiments of the present invention will now be described, by way of example only, with reference to the attached Figures, wherein:

[0044] Figure 1A depicts the geographical distribution of consumption globally;

[0045] Figure 1B depicts the geographical distribution worldwide of oil production;

[0046] Figure 1C depicts the geographical distribution worldwide of oil reserves;

[0047] Figure 2 depicts a typical SAGD well pair orientation;

[0048] Figures 3A and 3B depict outflow control devices according to the prior art of Forbes in US Patent Application 2008/0,251,255 for injecting fluid into an oil bearing structure;

[0049] Figure 4 depicts a SAGD process according to the prior art;

[0050] Figure 5 depicts a SAGD well pad;

[0051] Figure 6 depicts a typical modern SAGD well pair array;

[0052] Figure 7 depicts a well pad orientation and layout according to an embodiment of the invention;

[0053] Figure 8 is a table of typical SAGD operating parameters.

DETAILED DESCRIPTION

[0054] The present invention is directed to thermal oil recovery and more specifically to exploiting down hole thermal properties in oil recovery.

[0055] As discussed *supra* SAGD accordingly embodiments of the invention employ an injection well bore and a production well bore.

[0056] Now referring to Figure 4 there is depicted there are depicted SAGD process cross-section according to the prior art wherein a pair of wells are viewed in cross-section according to standard process. Accordingly in each case there are shown a pair of wells 420, consisting of an upper steam injection well and lower production well. These are disposed into the reservoir 410.

This oil sand layer 410 being disposed beneath rock overburden 470 that extends to the surface. In the standard SAGD process both injection and production occur at approximately the same point in the well bore heel 430 and 440 resulting in cooler points radiating outward from that point until the toe 450 and 460 of the well is reached.

[0057] Now referring to Figure 5 there is indicated typical SAGD surface equipment 530 for injecting into injection wells 510 and producing from production wells 520 all from a single well pad.

[0058] Now referring to Figure 6 wherein groups of wells are disposed across the oil sands. Each group of wells each consisting of a vertically-spaced well pair comprising an injector well and a producer well pair 620.

[0059] The well configuration of each well pair 620 corresponds to a conventional SAGD well pair with multiple well pairs drilled from a single well pad 610.

[0060] Referring to Figure 7 the SAGD wells are orientated according to an embodiment of the invention wherein upper well 770 is depicted as substantially parallel with each lower well 780. However, it is understood variations may arise through the local geology and topography of the reservoir within which a plurality of wells are drilled. Lower well 780 is defined to be adjacent and associated with upper well 770 as a functional set. Additional upper and lower wells can be similarly disposed in the array.

[0061] The wells 770 and 780 are formed in a conventional manner using known techniques for drilling horizontal wells into a formation. The size and other characteristics of the well and the completion thereof are dependent upon the particular structure being drilled as known in the art. The upper horizontal wells 770 may be established near an upper boundary of the formation in which they are disposed, and the lower horizontal wells 780 may be disposed towards a lower boundary of the formation.

[0062] Each lower horizontal well 780 is vertically spaced a distance from its respectively associated upper horizontal wells 770 (e.g., lower well 780 relative to each of upper wells 770) for allowing fluid communication, and thus fluid drive to occur, between the two respective upper and lower wells. Preferably this vertical spacing is the maximum such distance through the implementation of the method according to embodiments of the present invention.

[0063] The present invention is not limited to any specific dimensions because absolute spacing distances depend upon the nature of the formation in which the wells are formed as well as other factors such as the specific gravity of the oil within the formation. Accordingly, in initiating the wells to production a fluid is flowed into the one or more upper wells 770 and lower wells 780 in a conventional manner, such as by injecting in a manner known in the art. The fluid is one which improves the ability of hydrocarbons to flow in the formation so that they more readily flow both in response to gravity and a driving force provided by the injected fluid. Such improved mobility can be by way of heating, wherein the injected fluid has a temperature greater than the temperature of hydrocarbons in the formation so that the fluid heats hydrocarbons in the formation.

[0064] A particularly suitable heated fluid is steam having any suitable quality and additives as needed.

[0065] As the fluid is being injected via surface equipment 750 and 760 into both the lower well(s) 780 and the upper well(s) 770 to increase the temperature in the region, the first section, the heel, of both the upper well 720 and lower well 710 are heated rapidly and via convection they also begin to heat the area around the toe 730 and 740 of each respective well bore. As injection continues both wells 770 and 780 linearly increase in temperature so that as the heels 710 and 720 reach maximum temperature the excess heat is continually transferred further and further down the well bore until ideally there is now even heating of both well bores along their entire length allowing for faster SAGD start up with fewer localized hot spots and more efficient recovery rates. At that point lower well 780 is switched to production via surface equipment 750.

[0066] Figure 8 depicts typical SAGD operating parameters as is known in the prior art.

CLAIMS

What is claimed is:

1. A method comprising:
drilling a first well within an oil bearing structure from one well pad;
drilling a second well within the oil bearing structure in predetermined relationship with the first well from a second well pad;
according to a schedule injecting a heated mobilizing fluid into at least one of the first or second wells under first predetermined conditions;
operating the wells as a SAGD well pair so that the lower of the two wells extracts oil from the oil bearing structure.

2. A method according to claim 1 wherein,
the heel of the first well is positioned proximate to the toe of the second well.

3. The method according to claim 1 wherein,
the heel of the second well is positioned proximate to the toe of the first well.

4. The method according to claim 1 wherein,
the fluid is at least one of steam, water, carbon dioxide, nitrogen, propane and methane.

5. The method according to claim 1 wherein,
the schedule involves injecting a heated fluid into the upper well.

6. The method according to claim 1 wherein,
the schedule involves injecting a heated fluid into the lower well.

7. The method according to claim 1 wherein,

the first and second wells form a well pair comprising a predetermined portions of an array of horizontal well pairs.

8. The method according to claim 1 further comprising;
employing separate well pads for drilling and completing each of the first and second wells.

9. The method according to claim 1 wherein;
the first and second wells are disposed in mirror image to each other.

10. A method comprising:
drilling a first well within an oil bearing structure from one well pad;
drilling a second well within the oil bearing structure so that the heel of the second well is located proximate to the toe of the first well from a second well pad;
according to a schedule injecting a heated mobilizing fluid into the first and second wells under first predetermined conditions;
operating the wells as a SAGD well pair so that the lower of the two wells extracts oil from the oil bearing structure.

12. A method according to claim 10 wherein,
the heel of the first well is positioned proximate to the toe of the second well.

13. The method according to claim 10 wherein,
the heel of the second well is positioned proximate to the toe of the first well.

14. The method according to claim 10 wherein,
the fluid is at least one of steam, water, carbon dioxide, nitrogen, propane and methane.

15. The method according to claim 10 wherein,
the schedule involves injecting a heated fluid into the upper well.

16. The method according to claim 10 wherein,
the schedule involves injecting a heated fluid into the lower well.

17. The method according to claim 10 wherein,
the first and second wells form a well pair comprising a predetermined portions of an array of horizontal well pairs.

18. The method according to claim 10 further comprising;
employing separate well pads for drilling and completing each of the first and second wells.

19. The method according to claim 10 wherein;
the first and second wells are disposed in mirror image to each other.

Figure 1A

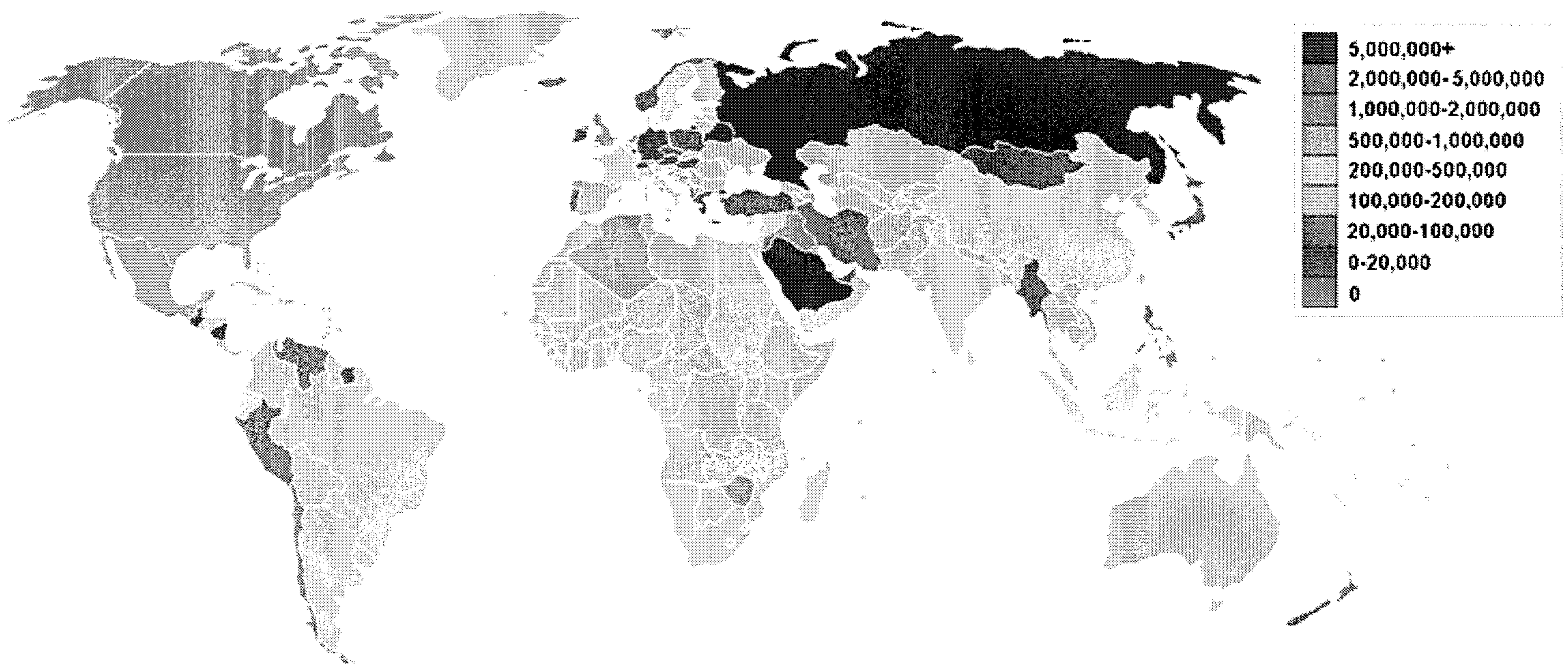
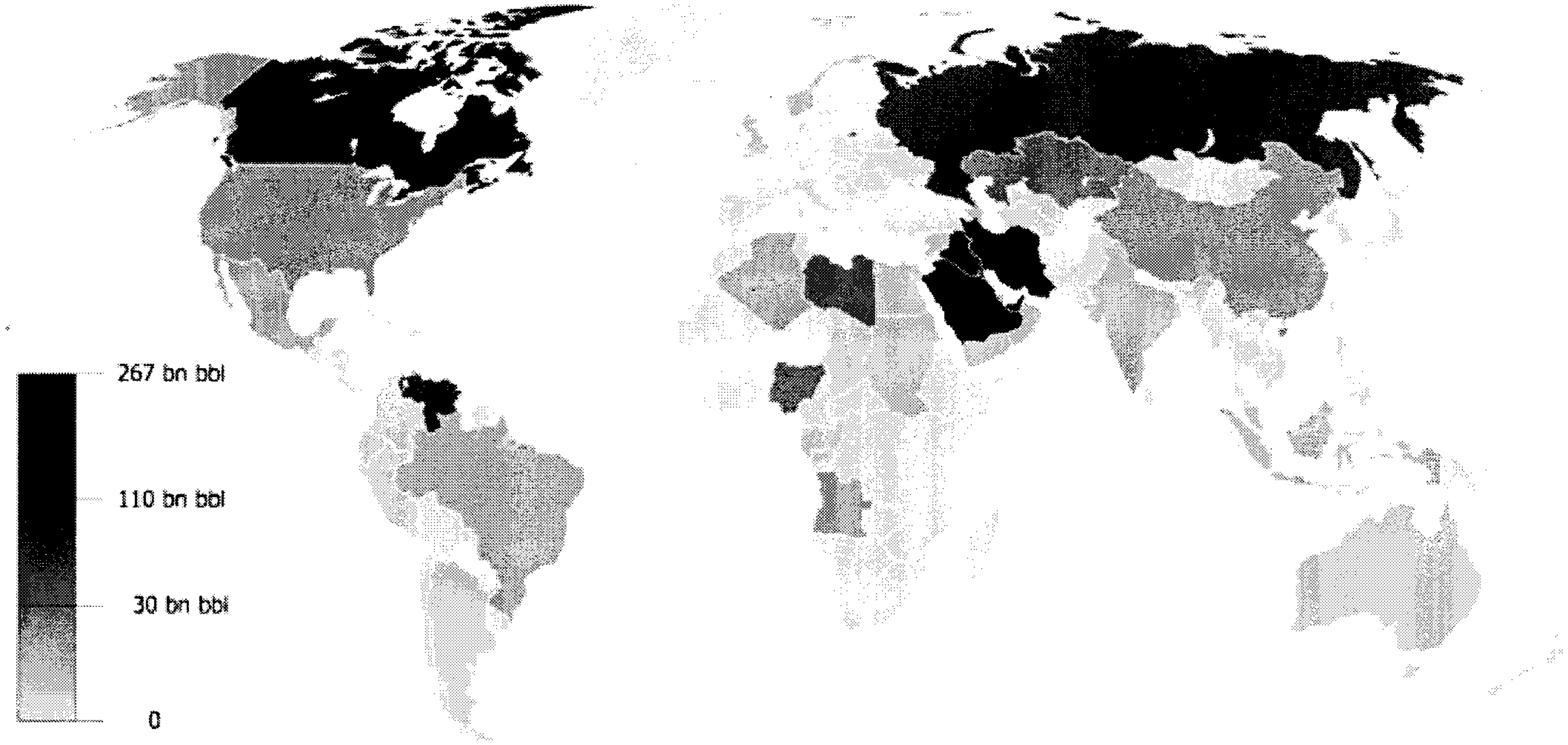
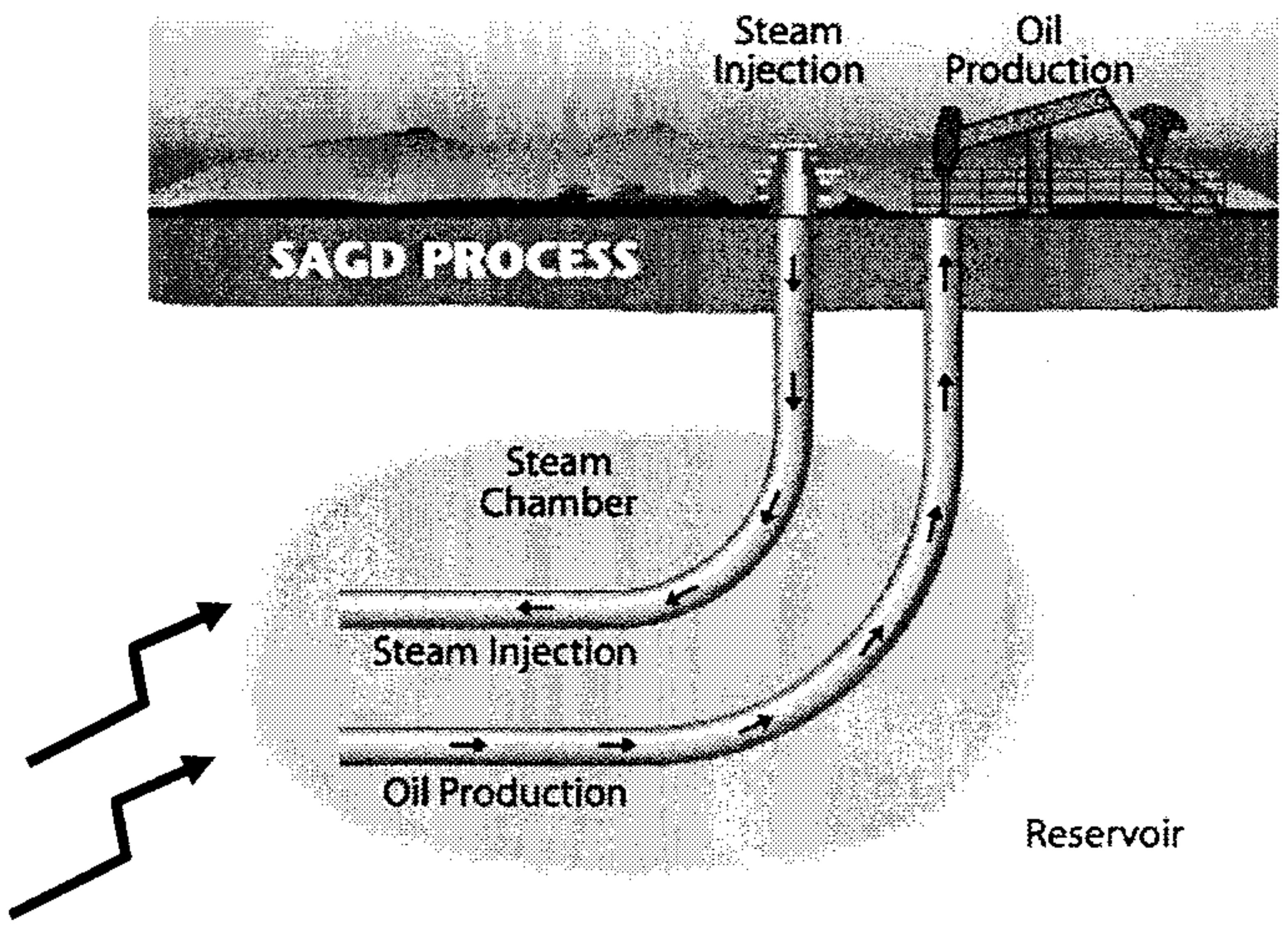


Figure 1B

Figure 1C





Source: Canadian Centre for Energy Information

210

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Figure 2

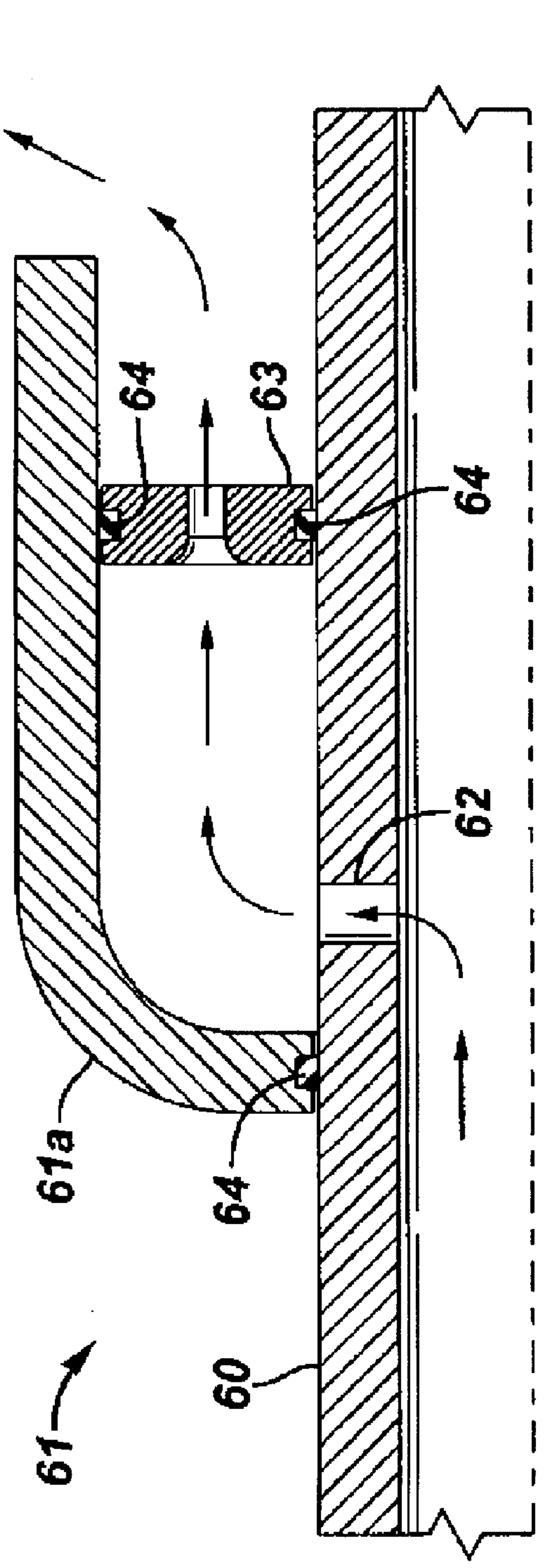


Figure 3A

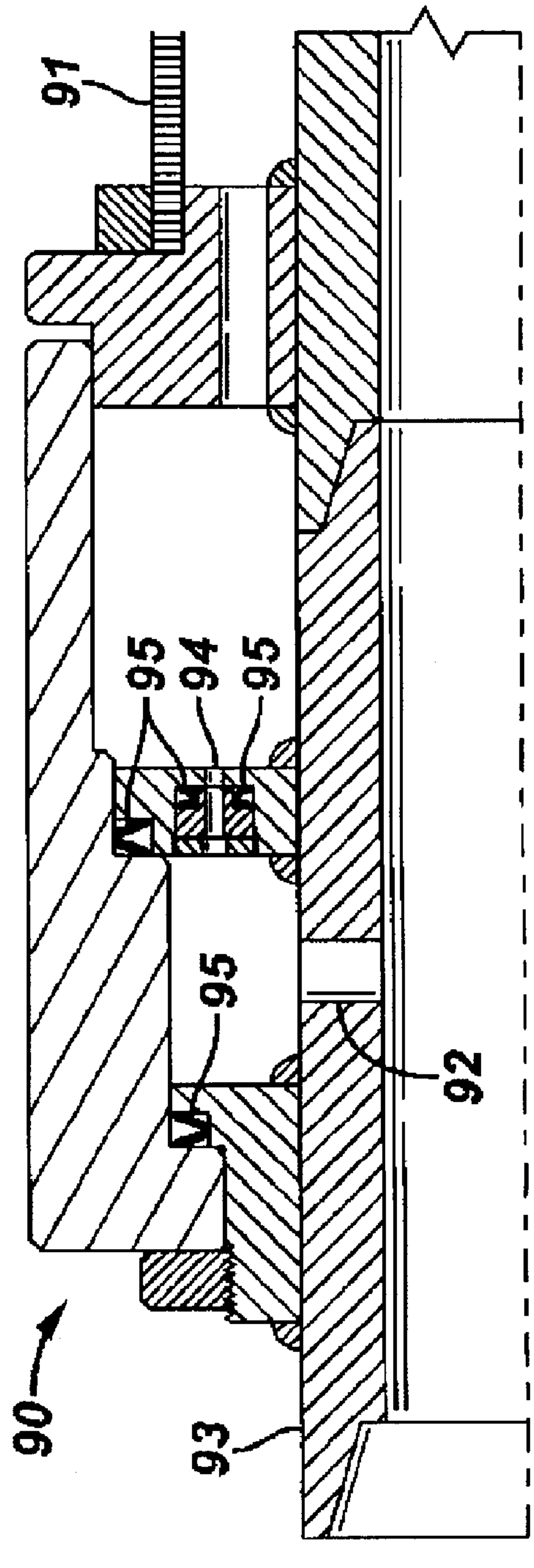


Figure 3B

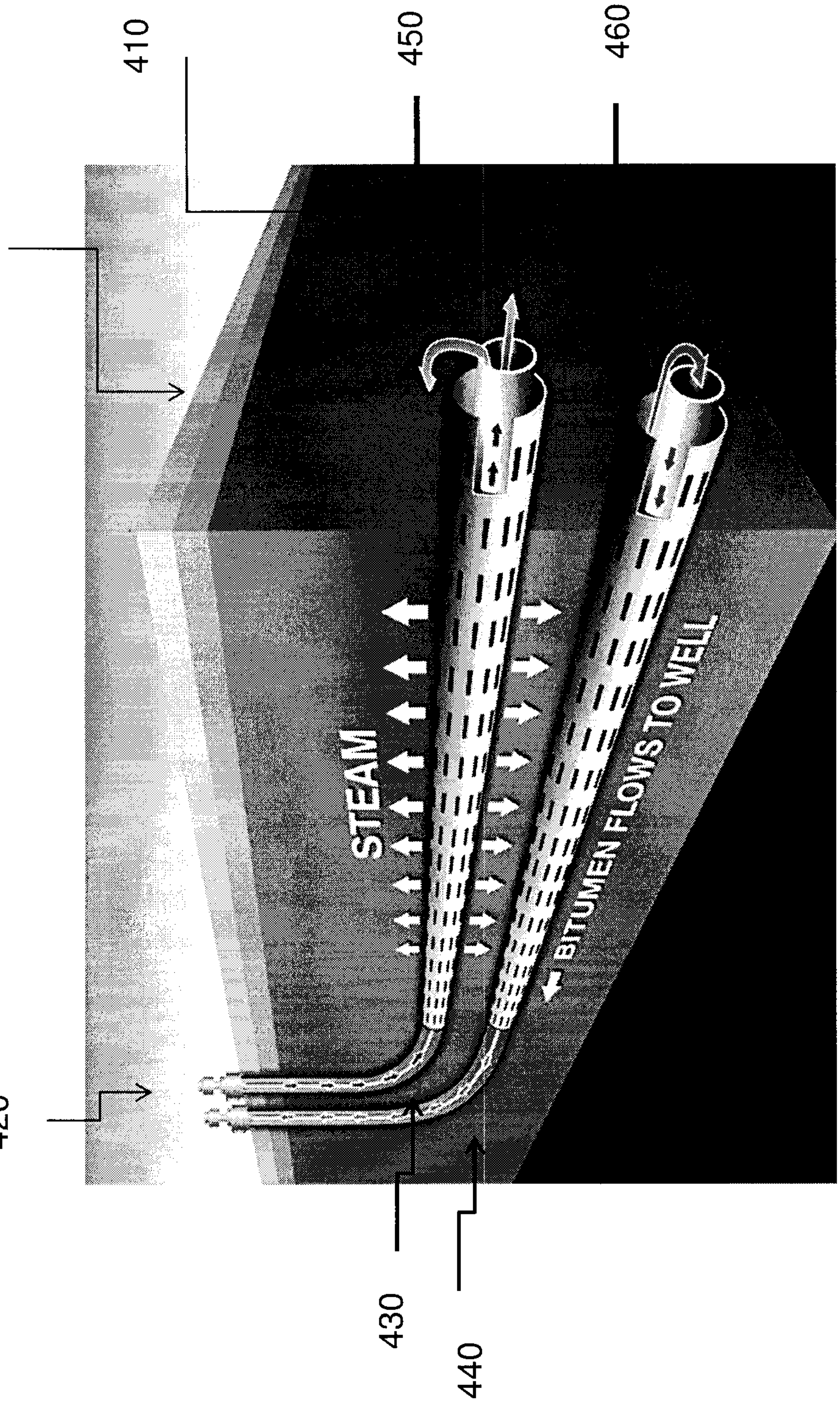


Figure 4

Figure 5

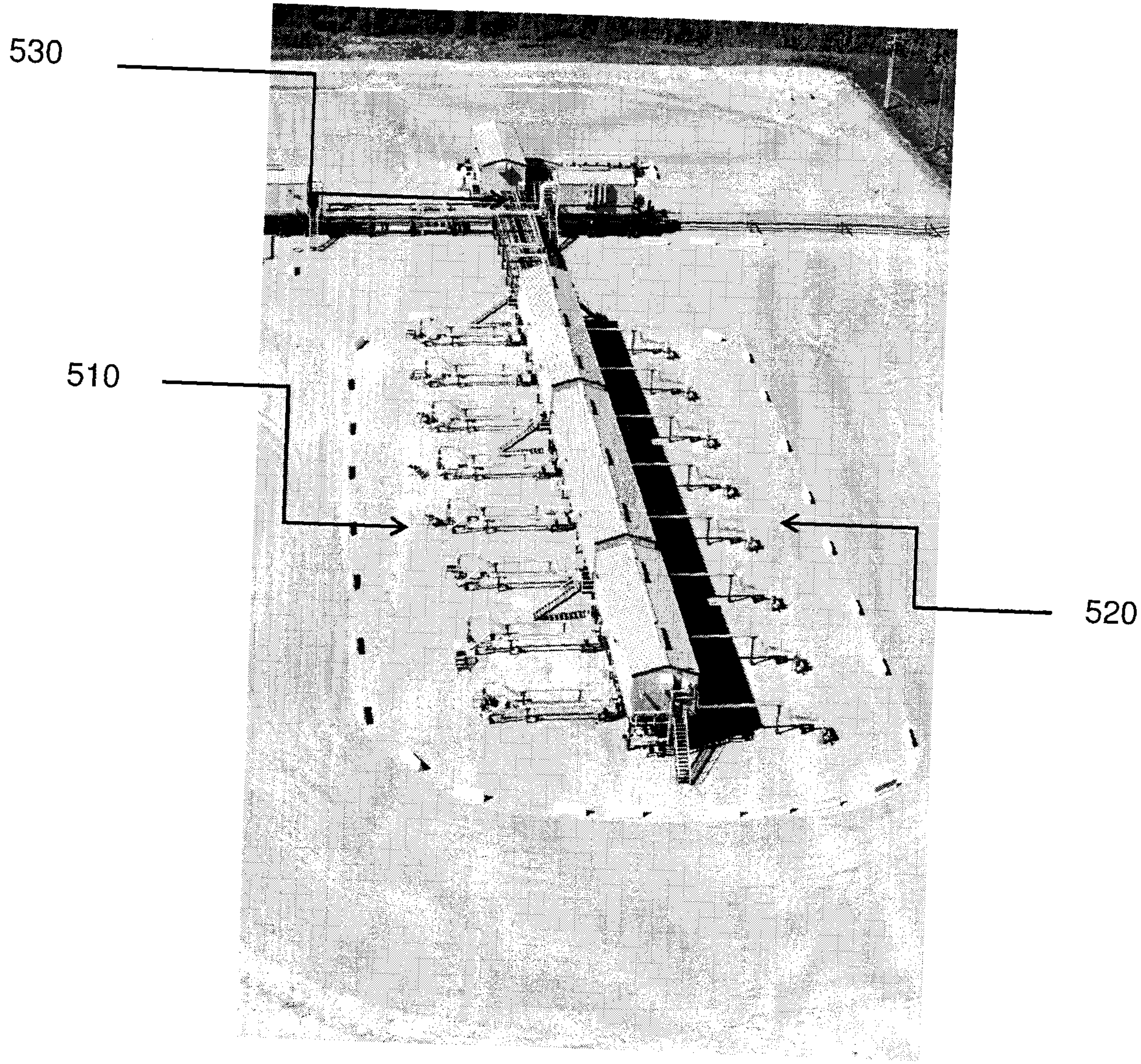
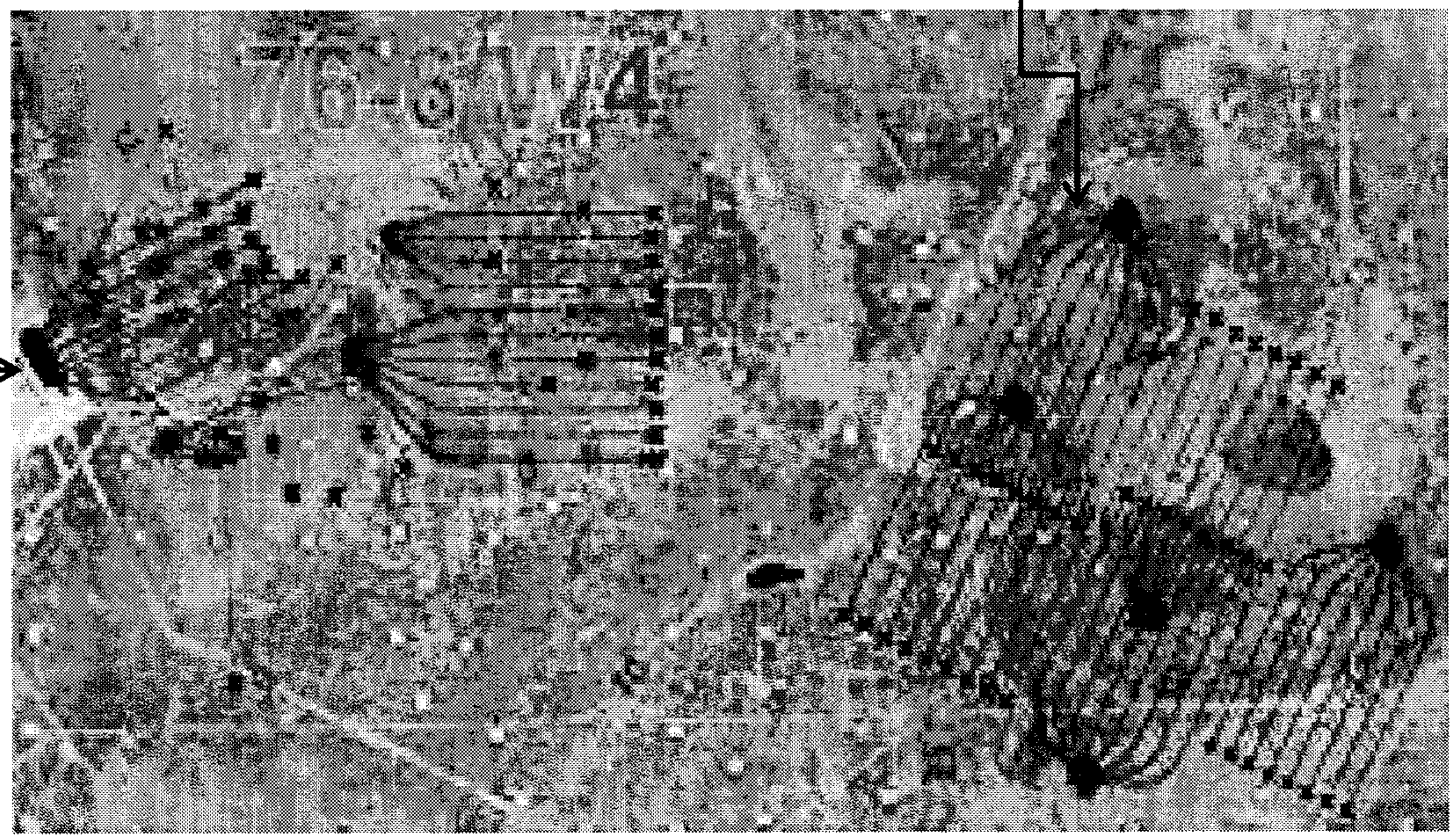


Figure 6



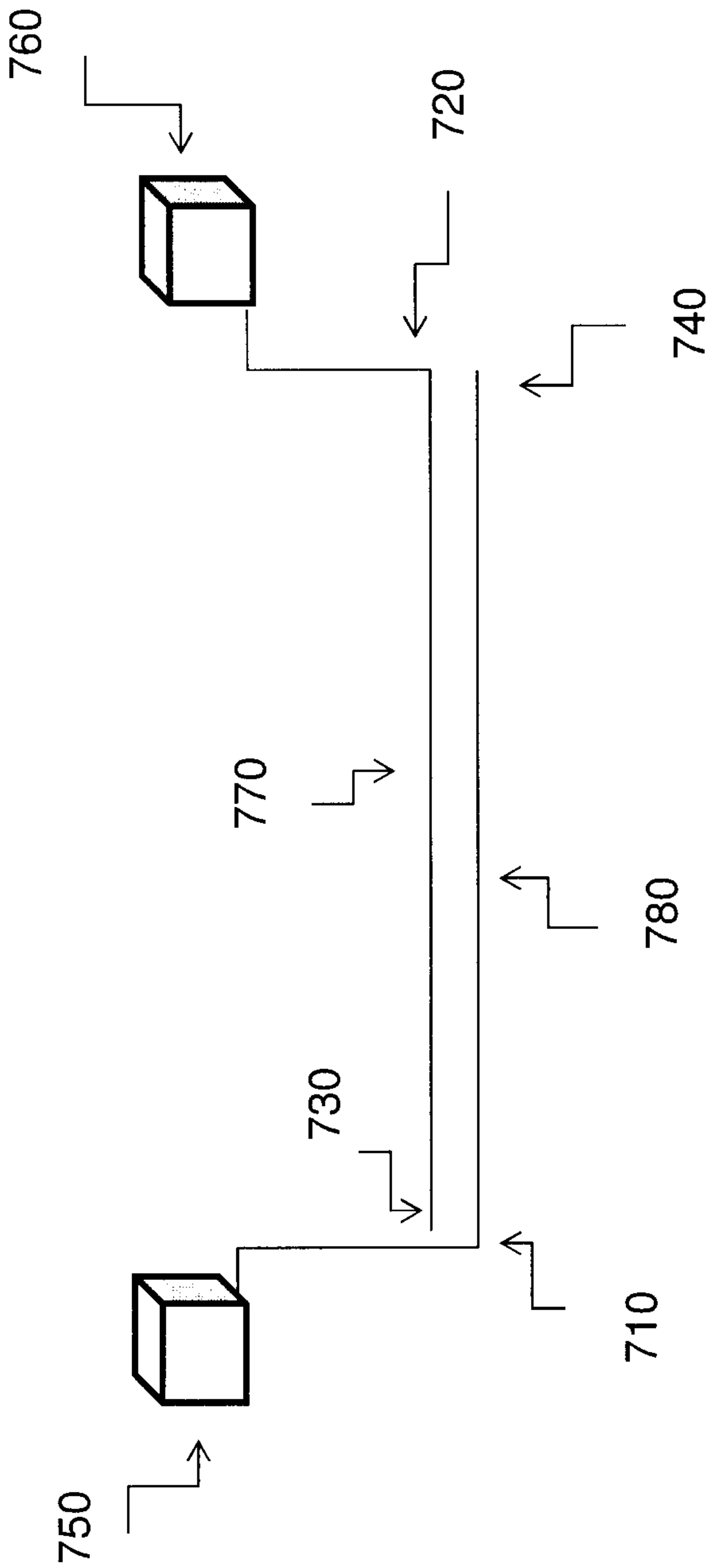
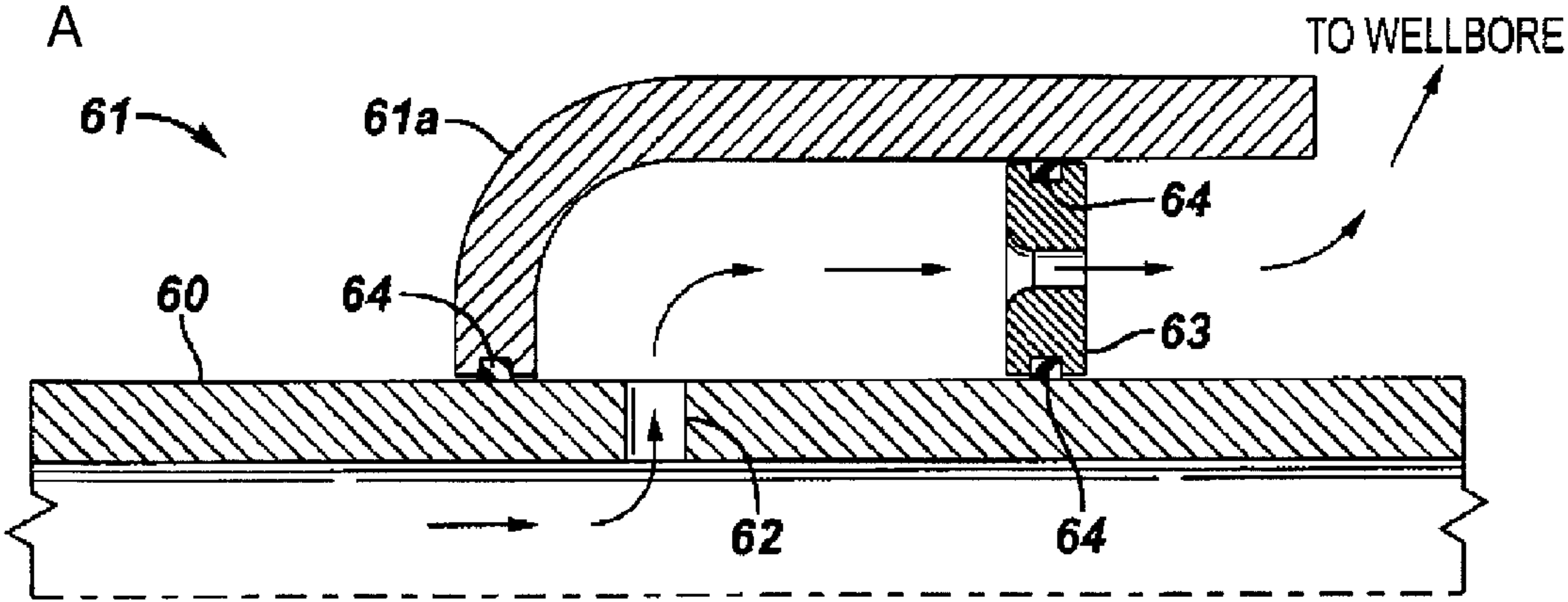


Figure 7

Figure 8

Parameter	Value
Injection Pressure	1800kPa
Steam Quality	0.9
Steam Temperature	200°C
Well Length	700m
Preheating Days	90


A
TO WELLBORE
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61a
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64