



(22) **Date de dépôt/Filing Date:** 2013/03/19

(41) **Mise à la disp. pub./Open to Public Insp.:** 2013/11/30

(45) **Date de délivrance/Issue Date:** 2016/05/31

(62) **Demande originale/Original Application:** 2 810 022

(30) **Priorité/Priority:** 2012/05/31 (US61/654,034)

(51) **Cl.Int./Int.Cl.** **C10G 31/06** (2006.01),
C10G 21/00 (2006.01), **E21B 43/22** (2006.01),
E21B 43/24 (2006.01), **E21B 43/30** (2006.01),
E21B 43/38 (2006.01), **E21B 43/40** (2006.01)

(72) **Inventeurs/Inventors:**

PEREIRA-ALMAO, PEDRO RAFAEL, CA;
CHEN, ZHANGXING, US;
MAINI, BRIJ, CA;
SCOTT, CARLOS EDUARDO, CA

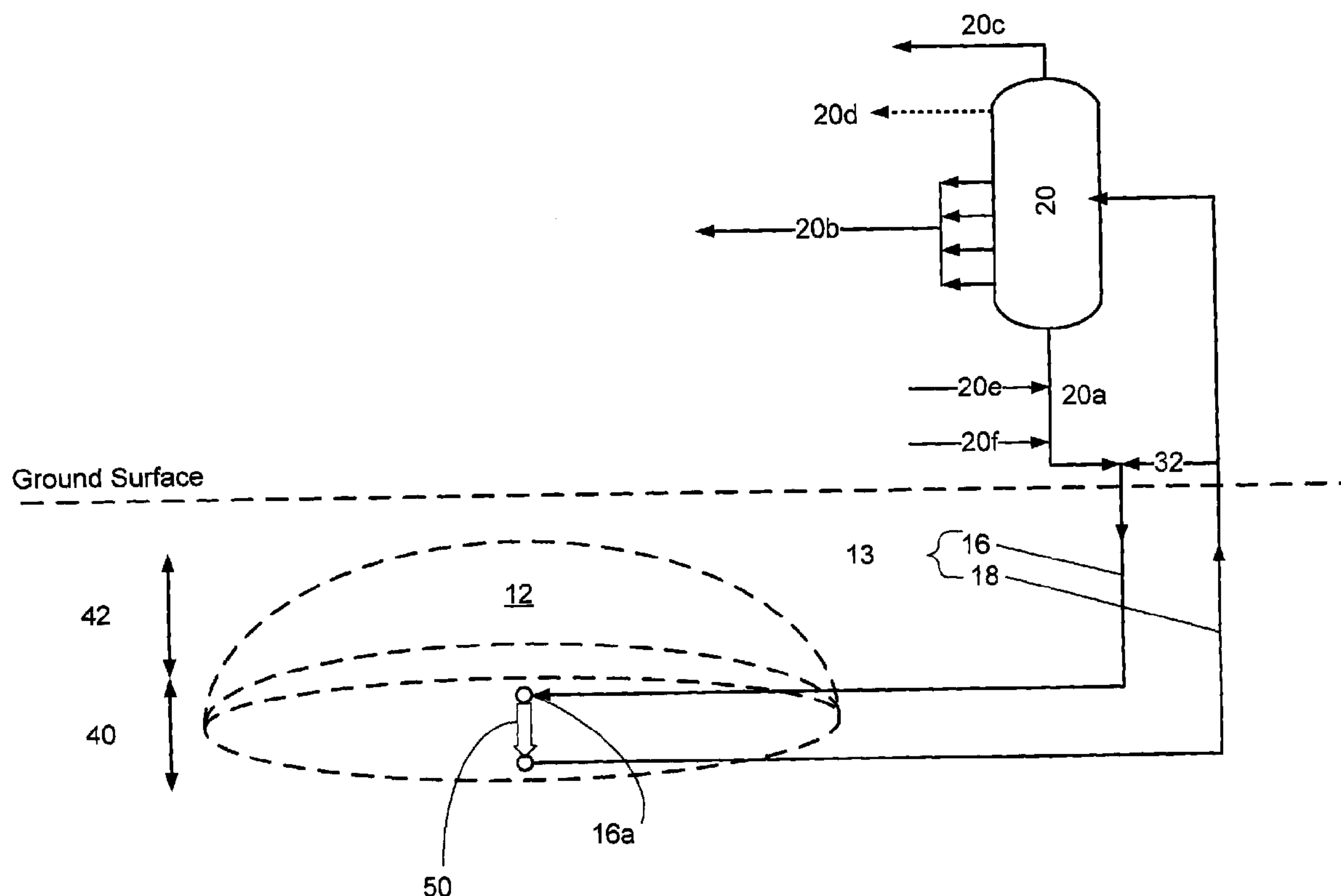
(73) **Propriétaire/Owner:**

IN SITU UPGRADING TECHNOLOGIES INC., CA

(74) **Agent:** HICKS & ASSOCIATES

(54) **Titre : VALORISATION IN-SITU PAR LE BIAIS D'UNE INJECTION DE FLUIDE CHAUD**

(54) **Title: IN SITU UPGRADING VIA HOT FLUID INJECTION**



(57) **Abrégé/Abstract:**

The invention relates to systems, apparatus and methods for integrated recovery and in-situ (in reservoir) upgrading of heavy oil and oil sand bitumens. The systems, apparatus and methods enable enhanced recovery of heavy oil in a production well by introducing a hot fluid including a vacuum or atmospheric residue fraction or deasphalted oil into the production well under conditions to promote hydrocarbon upgrading. The methods may further include introducing hydrogen and a catalyst together with the injection of the hot fluid into the production well to further promote hydrocarbon upgrading reactions. In addition, the invention relates to enhanced oil production methodologies within conventional oil reservoirs.

ABSTRACT

The invention relates to systems, apparatus and methods for integrated recovery and *in-situ* (in reservoir) upgrading of heavy oil and oil sand bitumens. The systems, apparatus and methods enable enhanced recovery of heavy oil in a production well by introducing a hot fluid including a vacuum or atmospheric residue fraction or deasphalted oil into the production well under conditions to promote hydrocarbon upgrading. The methods may further include introducing hydrogen and a catalyst together with the injection of the hot fluid into the production well to further promote hydrocarbon upgrading reactions. In addition, the invention relates to enhanced oil production methodologies within conventional oil reservoirs.

***IN SITU* UPGRADING VIA HOT FLUID INJECTION**

FIELD OF THE INVENTION

[0001] The invention relates to systems, apparatus and methods for integrated recovery and *in-situ* (in reservoir) upgrading of heavy oil and oil sand bitumens. The systems, apparatus and methods enable enhanced recovery of heavy oil in a production well by introducing a hot fluid including a vacuum or atmospheric residue fraction or deasphalted oil into the production well under conditions to promote hydrocarbon upgrading. The methods may further include introducing hydrogen and a catalyst together with the injection of the hot fluid into the production well to further promote hydrocarbon upgrading reactions. In addition, the invention relates to enhanced oil production methodologies within conventional oil reservoirs.

BACKGROUND OF THE INVENTION

[0002] *In situ* recovery methods for heavy oil or bitumen are often used in reservoirs where the depth of the overburden is too great for surface mining techniques to be used in an economical manner. Being highly viscous, heavy oil and bitumen do not flow as readily as lighter oil. Therefore most bitumen recovery processes involve reducing the viscosity of the bitumen such that the bitumen becomes more mobile and can flow from a reservoir to a production well. Reducing the viscosity of the bitumen can be realized by raising the temperature of the bitumen and/or diluting the bitumen with a solvent.

Steam Assisted Gravity Drainage

[0003] Steam Assisted Gravity Drainage (SAGD) is a known technique to extract bitumen from an underground reservoir. In a typical SAGD process, two horizontal wells, (a bottom well and an upper well) are drilled substantially parallel to and overlying one another at different depths. The bottom well is the recovery well and is typically located just above the base of the reservoir. The upper well is the injection well and is located about 5 to 10 meters above the recovery well. Steam is injected into the upper well to form a steam chamber within the formation that, over time, grows predominantly vertically towards the top of the reservoir and downwardly towards the recovery well. The steam raises the temperature of the surrounding bitumen in the reservoir,

decreasing the viscosity of the bitumen and allowing the bitumen and condensed steam to flow by gravity into the lower recovery well. The bitumen and condensed steam either flow or are pumped from the recovery well to the surface for separation and further processing. At surface, the separated bitumen is often blended with a diluent such that the bitumen and diluent can be easily transported to a refinery through a pipeline. At the refinery, the diluent is removed and the bitumen is subjected to various processes to separate and upgrade the bitumen into useful products. Principally, bitumen will be subjected to a vacuum distillation process to separate residual, heavy and light components from the bitumen for use in various upgrading processes.

[0004] SAGD is generally a very effective methodology of recovering heavy oil or bitumen from the formation to the surface. However, as is known, there are high capital and operating costs associated with SAGD, particularly with respect to the costs of building and operating a steam generation plant and recovery system at the drilling site. In addition, as large amounts of water are required for SAGD, a source of water must be available at the site or water needs to be transported to the site. Large amounts of fuel are also needed for SAGD to raise the temperature of the water to create steam. Further still, the production of high-quality steam from recovered water requires a substantial degree of conditioning at surface to clean the recovered water before reconvertng the recovered water back to steam. This conditioning generally requires that the recovered water that is mixed with the produced bitumen must first be separated from the produced bitumen and then subjected to further cleaning to remove any residual contaminants from the water. Upon these cleaning steps, the produced water must then be reheated to produce the high-quality steam for subsequent re-introduction back into the reservoir. As such, the cleaning and re-heating steps require substantial inputs of additional energy both to drive the cleaning processes as well as to re-heat the produced water back to steam. While some energy from the processes can be recovered through heat exchangers, inefficiencies in the processes result in the need for substantial additional energy to be input into the system.

[0005] Thus, while SAGD processes are effective, there are substantial environmental costs associated with large-scale SAGD production and specifically that SAGD has a carbon-footprint which is considerably greater than other forms of hydrocarbon production. As a result, there is a need for heavy oil production methodologies that

improve the efficiency and particularly the environmental impact of heavy oil production from heavy oil reservoirs.

Vertical Injection/Recovery Wells

[0006] Other recovery techniques include the use of one or more vertical wells as a means of applying heat into a reservoir to facilitate hydrocarbon mobility. For example, a single vertical well may be used for cyclic steam stimulation (CSS) which includes successive periods of steam injection, soaking and production. Similarly, two or more vertical wells in proximity to one another may be utilized where, after a start-up period where heat is introduced into the reservoir, one or wells are utilized to apply heat to the reservoir and one or more wells are utilized as production/recovery wells.

VAPEX

[0007] Another known *in situ* recovery process for bitumen or heavy oil is a vapor extraction process (VAPEX), which injects a gaseous solvent (i.e. propane, ethane, butane, etc.) into the upper injection well where it condenses and mixes with the bitumen to reduce the viscosity of the bitumen. The bitumen and dissolved solvent then flow into a lower production well under gravity where they are brought to the surface.

[0008] VAPEX is generally considered as being more environmentally friendly and in some circumstances more commercially viable than SAGD, as VAPEX does not require the large amount of water and steam generation that SAGD does. However, the gaseous solvent generally needs to be transported to the production site, and a lengthy start-up interval exists with VAPEX, as it takes longer to grow a vapor chamber with gaseous solvents compared to steam.

[0009] In addition, as VAPEX is a non-thermal process conducted at normal reservoir temperatures, it is not efficient in promoting upgrading reactions.

[0010] Thus, there are also significant limitations with respect to widespread use of VAPEX.

Catalytic Upgrading

[0011] Certain methodologies may incorporate the use of hydrocracking catalysts to assist in the recovery/upgrading process for upgrading and recovering heavy oil and bitumen. However, hydrocracking catalyst particles do not disperse well in the presence

of water, as catalyst minerals tend to preferentially migrate to the aqueous phase, and once there, become less available for reactions with hydrocarbons. In addition, water has a limited capacity for carrying dispersed particles through sand formations because of the low viscosity of water. Therefore, while steam and water are not catalyst poisons, dispersing catalyst particles in a SAGD chamber dominated by condensate and steam is thought to present significant technical challenges.

[0012] Furthermore, at temperatures less than 150°C, the viscosity of bitumen, or vacuum residue, is generally considered to be too high for effective incorporation of catalyst particles and gases such as hydrogen. In other words, in highly viscous bitumen, reaction times are slow due to mass transfer limitations on top of kinetic limitations due to that relatively low energy level.

Enhanced Oil Recovery

[0013] In addition to heavy oil reservoirs, other reservoir types including conventional reservoirs having passed peak production and carbonate formations continue to be investigated for new or enhanced oil recovery (EOR) techniques. In conventional reservoirs with decreasing production rates, there continues to be a need for cost-effective methodologies to promote recovery and/or decrease the rates of decline in such reservoirs. In addition, techniques for hydrocarbon production from different carbonate formations continue to be of interest as oil companies seek to exploit these types of reservoirs. As such, new EOR techniques are of interest.

Prior Art

[0014] The prior art has many examples of various recovery techniques. For example, recovery techniques that utilize a combination of steam and solvent injections have been proposed. U.S. Patent Publication 2005/0211434 teaches a SAGD recovery process utilizing a higher cost production start-up phase where steam and a heavy hydrocarbon solvent are injected into a reservoir and a lower cost later production phase where a light hydrocarbon solvent is injected into the reservoir to assist in the mobilization of bitumen.

[0015] U.S. Patent 4,444,261 teaches a method to improve the sweep efficiency of a steam drive process in the recovery of oil with a vertical production well spaced apart from a vertical injection well. In this technology, steam is injected into the formation via the injection well until steam flooding occurs or there is a steam-swept zone in the upper

portion of the formation. Next, a high molecular weight hydrocarbon is injected into the steam-swept zone at a high temperature (500-1000°F) as a diverting fluid and allowed to cool until it forms an immobile slug in the steam-swept zone. Once the slug is formed, steam injection is resumed and the slug diverts the steam to pass below the slug and below the steam-swept zone, thereby mobilizing the lower portions of oil. In another example, United States Patent No. 6,662,872 teaches a combined steam and vapor extraction process in a SAGD type recovery system.

[0016] As upgrading is commonly done to bitumen or heavy oil after it has been recovered, several technologies propose the concept of *in situ* upgrading, whereby heavy oil's viscosity is permanently reduced and its API gravity is increased as the oil is being produced. For example, United States Patent No. 6,412,557 teaches an *in situ* process for upgrading bitumen in an underground reservoir in which an upgrading catalyst is immobilized downhole and an *in situ* combustion process is used to provide heat to facilitate upgrading in a "toe-to-heel" process.

[0017] In other examples, United States Patent No. 7,363,973 discloses a method for stimulating heavy oil production in a SAGD operation using solvent vapors in which *in situ* upgrading may be involved and United States Publication No. 2008/0017372 discloses an *in situ* process to recover heavy oil and bitumen in a SAGD type recovery system using C3+ (more specifically C3-C10) solvents. Upgrading is described as inherently occurring in view of the solvents contacting the bitumen.

[0018] A further example is shown in United States Patent Publication 2006/0175053 that describes a process to improve the extraction of crude oil. This process utilizes an insulated pipe to convey hot fluids to the formation to facilitate extraction. The hot fluids may include paraffins and asphaltenes.

[0019] Accordingly, while various technologies continue to be developed that advance upon the general methodologies of SAGD and VAPEX, there continues to be a need for improved *in-situ* recovery method in which large amounts of water or gaseous solvents do not need to be shipped to the production site, nor in which a large amount of steam and water are present in the reservoir. As well, improved forms of *in situ* upgrading techniques are generally needed that are more economical, efficient, and are able to recover a higher proportion of oil.

[0020] Further still, there has been a need for improved EOR and oil recovery techniques that may be utilized in conventional reservoirs and carbonate formations.

SUMMARY OF THE INVENTION

[0021] In accordance with the invention, there is provided systems and methods for *in situ upgrading* of hydrocarbons within a hydrocarbon formation.

[0022] In a first aspect, a method for recovery and *in situ* upgrading of hydrocarbons in a well pair having an injection well and a recovery well within a heavy hydrocarbon reservoir is provided, the method comprising the steps of: a) introducing a selected quantity of a hot injection fluid including a heavy hydrocarbon fraction into the injection well to promote hydrocarbon recovery and *in situ* upgrading; and b) recovering hydrocarbons from the recovery well.

[0023] In another embodiment, the heavy hydrocarbon fraction is selected from any one of or a combination of shale oil, bitumen, atmospheric residue, vacuum residue, or deasphalted oil.

[0024] In further embodiments, the hydrocarbons recovered from the recovery well are subjected to a separation process wherein heavy and light fractions are separated and wherein the heavy fraction includes a residue fraction.

[0025] In another embodiment, the residue fraction from the separation process is mixed with the injection fluid prior to introduction into the injection well.

[0026] In another embodiment, the method further comprises the step of mixing make-up heavy hydrocarbons with the injection fluid prior to introducing the injection fluid into the injection well and wherein the temperature and pressure of the injection fluid is controlled to promote downhole upgrading reactions.

[0027] In another embodiment, the injection fluid includes diluent.

[0028] In further embodiments, the temperature and pressure of the injection fluids are controlled to promote thermal cracking upgrading reactions.

[0029] In yet further embodiments, the temperature of the injection fluid is controlled to provide a downhole sump temperature of $320\pm 20^{\circ}\text{C}$ and/or the downhole residence time of injected fluids is 24-2400 hours.

[0030] In another embodiment, the temperature and pressure of the injection fluids are controlled such that greater than 30% of residual heavy hydrocarbon of the recovered bitumen is upgraded into lighter fractions.

[0031] In another embodiment, the temperature and pressure of the injection fluids are controlled such the recovered hydrocarbons have a viscosity less than 500 cP at 25°C .

[0032] In another embodiment, the recovered hydrocarbons have a viscosity less than 250 cP at 25°C .

[0033] In yet a still further embodiment, prior to step a), steam is injected into the horizontal well pair to initiate connection between the injector well and the recovery well and formation of a downhole reaction chamber.

[0034] In another embodiment, prior to step a) the steam is progressively replaced with a heavy hydrocarbon fluid, selected from any one of or a combination of heavy oil, shale oil, bitumen, atmospheric residue, vacuum residue, or deasphalted oil.

[0035] In yet another embodiment, the method includes the step of mixing a catalyst into the injection fluid prior to introducing the injection fluid into the injection well.

[0036] In another embodiment, the method further comprises the step of mixing hydrogen into the injection fluid prior to introducing the injection fluid into the injection well.

[0037] In other embodiments, the temperatures and pressures of the injection fluid are controlled to promote any one of or a combination of hydrotreating, hydrocracking or steam-cracking reactions.

[0038] In another embodiment, the hydrogen is mixed with the injection fluid to provide excess hydrogen for the hydrotreating and hydrocracking reactions.

[0039] In yet another embodiment, the hydrogen is injected along the length of the injection well.

[0040] In another embodiment, approximately 1/3 of the hydrogen is mixed with the injection fluid at surface and approximately 2/3 is injected to the reservoir along the horizontal length of the recovery well.

[0041] In yet another embodiment, the hydrogen is injected from the recovery well via at least one liner operatively configured to the recovery well.

[0042] In various embodiments, the catalyst is any one of or a combination of nano-catalysts or ultradispersed catalyst wherein the nano-catalyst may have particles with dimensions less than 1 micron and/or less than 120 nm.

[0043] In another embodiment, a plurality of adjacent interconnecting well pairs are configured to a single well pad wherein one of the interconnecting well pairs is an upgrading well pair and wherein heavy hydrocarbon fluids recovered from each well is mixed with the injection fluid of the upgrading well pair.

[0044] In a further embodiment, the heavy hydrocarbon fluids include any one of or a combination of heavy oil, shale oil, bitumen, atmospheric residue, vacuum residue, or deasphalted oil

[0045] In another embodiment, the injection well and recovery well have vertically overlapping horizontal sections and the injection well is the lower of the injection well and the recovery well.

[0046] In a still further embodiment, the injection well and recovery well have vertically overlapping horizontal sections and the injection well is the upper of the injection well and the recovery well.

[0047] In another aspect, the invention provides a method of upgrading heavy hydrocarbons during hydrocarbon recovery from a heavy hydrocarbon formation comprising the steps of: a) drilling an injection well and recovery well into the heavy hydrocarbon formation; b) creating a hydrocarbon mobilization chamber within the heavy hydrocarbon formation by introducing a hot fluid into the injection well so as to promote hydrocarbon mobility to the recovery well; c) recovering heavy hydrocarbons from the recovery well to the surface; d) subjecting the recovered hydrocarbons from step c) to a separation process to form lighter hydrocarbon fractions and heavy residual hydrocarbon fractions; e) introducing a portion or all of the heavy residual hydrocarbon fractions at a temperature and pressure to promote hydrocarbon upgrading reactions in the hydrocarbon mobilization chamber; and, f) recovering co-mingled and upgraded hydrocarbons from the recovery well.

[0048] In another embodiment, a portion of the heavy residual fraction from the separation is used as a fuel to produce heat to heat the injection fluids for upgrading reactions.

[0049] In a further embodiment, the method further comprises the step of using a portion of the lighter hydrocarbons to additional separation processes for commercialization.

[0050] In another embodiment step e) includes introducing a catalyst into the injection well to promote catalytic upgrading within the injection well and the hydrocarbon mobilization chamber and/or step e) further includes introducing hydrogen into the injection well to promote upgrading reactions within the hydrocarbon mobilization chamber.

[0051] In yet another aspect, the invention provides a system for recovery and *in situ* upgrading of heavy hydrocarbons within a heavy hydrocarbon formation comprising: an injection well; a recovery well; the injection well and recovery well operatively connected to a hydrocarbon distillation column for separation of recovered fluids from the recovery well into heavy and light fractions; and, a mixing and hot fluid injection system operatively connected to the distillation column for recovering heavy fractions from the distillation column and for mixing the heavy fraction with additional injection fluids for injection into the injection well;

[0052] In another embodiment, the system further comprises a gas/liquid separation system operatively connected to the recovery well for separating gas and liquids recovered from the recovery well and for delivering separated liquids to the distillation column and/or a catalyst injection system operatively connected to the mixing and hot fluid injection system for introducing catalyst to the mixing and hot fluid injection system and/or a hydrogen injection system operatively connected to the mixing and hot fluid injection system for introducing hydrogen to the mixing and hot fluid injection system and/or a diluent injection system operatively connected to the mixing and hot fluid injection system for introducing diluent to the mixing and hot fluid injection system and/or at least one additional injection and recovery well operatively connected to the distillation column for introducing additional heavy hydrocarbons from the at least one additional recovery well to the distillation column.

[0053] In yet a further aspect, the invention provides a method of upgrading heavy hydrocarbons during hydrocarbon recovery from a heavy hydrocarbon formation

comprising the steps of: a) drilling an injection well and recovery well into the heavy hydrocarbon formation; b) creating a hydrocarbon mobilization chamber within the heavy hydrocarbon formation by introducing a hot fluid into the injection well so as to promote hydrocarbon mobility to the recovery well; c) recovering heavy hydrocarbons from the recovery well to the surface; d) subjecting the recovered hydrocarbons from step c) to a solvent deasphalting separation process to form a deasphalted oil and an asphaltic pitch; e) introducing deasphalted oil from step d) into the injection well at a temperature and pressure to promote hydrocarbon upgrading reactions in the hydrocarbon mobilization chamber; and, f) recovering co-mingled and upgraded hydrocarbons from the recovery well.

[0054] In another embodiment, a portion of the asphaltic pitch is used as a fuel to produce heat to heat the injection fluids for upgrading reactions.

[0055] In yet another embodiment, the method further comprises the step of using a portion of the lighter hydrocarbons to additional separation processes for commercialization.

[0056] In yet another aspect, the invention provides a system for recovery and *in situ* upgrading of heavy hydrocarbons within a heavy hydrocarbon formation comprising: an injection well; a recovery well; wherein the injection well and recovery well operatively connected to a solvent deasphalting system for recovering a deasphalted oil fraction for mixing with additional injection fluids for injection into the injection well.

[0057] In yet another aspect, the invention provides a method of upgrading heavy hydrocarbons during hydrocarbon recovery from a heavy hydrocarbon formation comprising the steps of: a) drilling a well into the heavy hydrocarbon formation; b) introducing heat into the well to create a hydrocarbon mobilization chamber within the heavy hydrocarbon formation so as to promote hydrocarbon mobility within the well; c) recovering heavy hydrocarbons from the recovery well to the surface and initially storing the heavy hydrocarbons in a heated tank; d) introducing heavy hydrocarbons from the heated tank into the well at a temperature and pressure to promote hydrocarbon upgrading reactions in the hydrocarbon mobilization chamber; e) sealing and maintaining pressure in the well for a time sufficient to promote hydrocarbon upgrading reactions; and, f) after a sufficient time, releasing the well pressure and recovering upgraded hydrocarbons from the well.

[0058] In other embodiments, the invention includes the steps of introducing catalyst into the well during step d); and/or introducing hydrogen into the well during step d).

[0059] In another aspect, the invention provides a method for recovery and *in situ* upgrading of hydrocarbons in a well pair having an injection well and a recovery well within a heavy hydrocarbon reservoir comprising the steps of: (a) introducing a selected quantity of a hot injection fluid including a heavy hydrocarbon fraction selected from any one of or a combination of shale oil, bitumen, atmospheric residue, vacuum residue, or deasphalted oil into the injection well to promote hydrocarbon recovery and *in situ* upgrading; (b) recovering hydrocarbons from the recovery well; (c) subjecting the hydrocarbons recovered from the recovery well to a separation process wherein heavy and light fractions are separated to produce any one of or a combination of shale oil, bitumen, atmospheric residue, vacuum residue and a deasphalted oil fraction; and, (d) re-introducing any one of the shale oil, bitumen, atmospheric residue, vacuum residue or deasphalted oil fraction into the well as a hot injection fluid under temperature and pressure conditions to promote upgrading and repeating steps (a) to (d).

BRIEF DESCRIPTION OF THE DRAWINGS

[0060] The invention is described with reference to the accompanying figures in which:

Figure 1 is a schematic diagram of a residue assisted *in situ* upgrading (RAISUP) process in accordance with a first embodiment of the invention;

Figure 2 is a schematic diagram of a residue assisted *in situ* catalytic upgrading (RAISCUP) process in accordance with a second embodiment of the invention;

Figure 2A is a schematic plan view of a RAISUP process utilizing multiple well pairs;

Figure 2B is a schematic cross view of various RAISUP processes using one or more vertical wells as injection/production wells;

Figure 3 is a schematic diagram of a recovery chamber in accordance with one embodiment of the invention;

Figure 4 is a schematic diagram of a typical temperature gradient in an upgrading well pair and recovery chamber in accordance with one embodiment of the invention;

Figure 5 is a schematic diagram of surface facilities for an upgrading well pair in accordance with another embodiment of the invention;

Figures 6 is a schematic diagram of surface facilities for an upgrading well pair in accordance with another embodiment of the invention utilizing deasphalted oil;

Figure 7 is a schematic diagram of the upgrading zones in accordance with the invention; and,

Figure 8 is a schematic diagram of another embodiment of the invention using a huff and puff methodology.

DETAILED DESCRIPTION OF THE INVENTION

Overview

[0061] In accordance with the invention and with reference to the figures, systems, apparatus and methods for *in situ* upgrading of hydrocarbons in hydrocarbon recovery operations are described. In particular, the methods enable upgrading of heavy oils and bitumen within a production well bore and formation chamber using hot injection fluids. In a first embodiment, the hot injection fluid includes a residue fraction. In a second embodiment, the injection fluid includes deasphalted oil. In both cases, hydrogen gas and a catalyst can be injected together with the hot residue or deasphalted oil to promote *in situ* upgrading and recovery of the heavy oils and bitumen.

[0062] In accordance with the invention and in the context of this description, the following general definitions are provided for the terms used herein. Extra heavy hydrocarbons are generally defined as those hydrocarbon fractions that are distilled above temperatures of 500°C (atmospheric pressure) or have an API gravity less than 10 (greater than 1000 kg/m³). Heavy hydrocarbons are distilled between temperatures of 350°C and 500°C or have an API gravity between 10 and 22.3 (920 to 1000 kg/m³). Medium hydrocarbons are distilled between temperatures of 200°C and 350°C and are generally defined as having an API gravity between 22.3 API and 31.1 API (870 to 920 kg/m³). Light hydrocarbons are defined as having an API gravity higher than 31.1 API (less than 870 kg/m³) and are distilled below 200 °C.

[0063] A residue fraction is the fraction that distills at temperatures higher than 540°C. A deasphalted oil (DAO) fraction is a crude fraction produced in a deasphalting unit (DAU) that separates asphalt from bitumen.

Residue Assisted In situ Upgrading (RAISUP)

[0064] In a first embodiment, as shown in Figure 1, the invention provides a system for Residue Assisted *In situ* Upgrading (RAISUP) in an *in situ* upgrading chamber 12 having an upgrading well pair 13. In accordance with this embodiment, one of the wells of the upgrading well pair is an injection well 16 and the other well is a recovery well 18. Well pairs may be horizontal, vertical or inclined and may comprise combinations of such wells as shown in Figure 2b. For the purposes of description, a horizontal well pair is described although it is understood that other combinations of well pairs may be utilized. Initially, hot fluid or steam is injected into the injection well, causing a chamber 12 to grow at and around the injection point 16a. The recovery well 18 serves to collect the recovered fluids, from which the recovered fluids flow or are pumped to the surface. At the surface, the recovered fluids enter an atmospheric and/or vacuum distillation column 20 where the heavy oil is separated into fractions by weight, leaving at the bottom of the distillation column a heavy vacuum or atmospheric residue fraction 20a (the “residue fraction”), and at higher levels of the column, lighter oil fractions 20b, recovered gases 20c and recovered diluent 20d (if utilized).

[0065] In accordance with the invention, the hot fluids injected into the injection well include the residue fraction 20a from the distillation column, additional bitumen 20e from another source and/or diluent 20f and/or other hot fluids including steam. Importantly, injecting the residue fraction promotes *in situ* thermal cracking/upgrading reactions to occur within the formation. In addition, the injection of a residue fraction affects the overall efficiency of upgrading reactions as the heavy oil fractions are most reactive to heat driven upgrading reactions.

[0066] Importantly, the “re-injection” of the hot residue fraction into the injection well is also an effective source of introducing heat into the chamber 12. Further still, while it is preferred that the residue is recovered from an at-site distillation column 20, it is understood that the residue fraction 20a may be formed elsewhere at the surface including being pumped to the site from other wells or processing centers that may be adjacent to or near the well as shown in Figures 2A and 2B.

[0067] Accordingly, in a preferred operation, the hot residue is produced in the distillation column 20 and re-injected into the injection well at around $350\pm 20^{\circ}\text{C}$ which ideally provides an average reservoir sump temperature of $320\pm 20^{\circ}\text{C}$. Importantly, as the injected hot residue temperature is thus generally higher than that of steam, the hot residue will cause the chamber to more rapidly expand during start-up operations and/or more rapidly maintain a steady state size.

[0068] In addition, a sump temperature of around $320\pm 20^{\circ}\text{C}$ promotes *in situ* thermal upgrading of the bitumen in the injection well and oil reservoir by increasing the temperature of the bitumen to a temperature at which upgrading reactions can occur (eg. thermal cracking), as well as decreasing the viscosity of the bitumen to improve the overall mobility of the bitumen in the reservoir.

[0069] Under steady state conditions, the residence time for the injected residue may vary between approximately 24-2400 (normal upper limit about 500) hours depending on the size of the chamber and the permeability of the porous media as understood by those skilled in the art. Recovered bitumen will be partially but significantly upgraded to produce a number of heavy oil products having a typical viscosity less than 300 cPois at 60°F and 14-15 API gravity as compared to a typical API gravity of 8-10 for recovered bitumen at similar conditions. Under typical conditions, a residence time of 24-48 hours will result in more than 30% of the recovered bitumen being upgraded.

[0070] A further advantage of hot residue injection in accordance with the invention is that the recovered oil is at a higher temperature and contains much less water than with steam injection. Accordingly, injecting hot residue can effectively eliminate the injection of water into the reservoir, such that the only water in the reservoir will be connate water. As a result, water treatment and/or water disposal costs will be eliminated or substantially reduced.

[0071] However, during start-up, steam can be injected into the injection well to begin growing the chamber during the start-up phases, in which case the steam is then progressively replaced with hot residue over time. Thus, during start-up, water treatment and recovery may be required. However, it should also be noted that steam use at this step could be replaced using heated oil from a storage tank and enabling recirculation of hot oil within the wells until the wells achieve connectivity. The selection of either steam

and/or heated oil to effect connectivity can be made based on the specifics of a series of wells and the economics of those wells.

[0072] Alternatively, hot oil (bitumen, Deasphalted oil, Vacuum Gas oil etc..) can be injected during the start-up phases and used to grow the chamber from the beginning if the economics of a particular project support this approach.

[0073] It should be noted that the use of hot residue to grow the chamber generally results in greater horizontal expansion of the chamber instead of vertical expansion due to the generally greater horizontal permeability of heavy oil formations in comparison to vertical permeability. Importantly, a more laterally expanded chamber may result in more complete recovery than the typical vertical chamber of SAGD processes, as greater horizontal expansion will result in a greater overall volume of the recovery chamber.

Residue Assisted In-situ Catalytic Upgrading (RAISCUP) Process

[0074] In accordance with another aspect of the invention and with reference to Figures 2-8, systems and methods for Residue Assisted *In situ* Catalytic Upgrading (RAISCUP) in a hydrocarbon recovery operation are described. In particular, these methods enable catalyst-assisted upgrading of heavy oils and bitumen within a production well bore and formation chamber having a well pair.

[0075] As shown in Figure 2, in this embodiment, catalyst 30 and hydrogen 28 are injected into the injection well to further promote upgrading reactions including hydrotreating and hydrocracking reactions in addition to thermocracking reactions. As in Figure 1, the system includes an upgrading well pair 13 consisting of an injection well 16 and a recovery well 18 in which the injection well serves as a point of entry for injected fluids 38 and the recovery well collects recovered fluids 44 which flow or are pumped to the surface. As explained in greater detail below, either well from the well pair may serve as the injection well. However, for the purposes of illustration in situations with one or more horizontal well pairs, Figures 2, 3, 4, 5, 6 and 7 illustrate the top well as the injection well 16 and the bottom well as the recovery well 18.

[0076] In one embodiment, the system is designed for use with a plurality of horizontal well pairs served by one well pad 50' in which one of the adjacent well pairs (50a, b, c, d) is used for upgrading reactions (Figure 2A). For example, bitumen recovered in adjacent well pairs (50 b, c, d) may be upgraded in well pair 50a in which all the bitumen

recovered from the adjacent well pairs (approximately 500 to 1000 barrels per day per well pair) could be upgraded in one upgrading well pair for efficiency reasons.

[0077] In this embodiment as shown in Figure 2, the injected fluids 38 preferably comprise hydrogen 28, column recovered residue fraction 20a, other bitumen 20e, diluent 20f (optional) and catalyst 30. As noted, the other bitumen 20e may include recovered bitumen from surrounding well pairs and/or other sources.

[0078] Initially, during start-up typically 10 to 15% diluent (condensate) 20f (Figure 1) may be added to hot bitumen to assist in the transport and mobility of bitumen into the well during start-up and explained in greater detail below. Once the upgrading well pair is undergoing steady *in situ* upgrading operation the diluent can be removed for recycling and no more bitumen is injected to the reservoir and instead the residual fraction from the distillation column is used.

[0079] During steady-state operation, incoming bitumen 20e and diluent 20f will be blended with hot residue 20a along with recovered and makeup hydrogen 28 and makeup catalyst 30 together with recovered hydrogen and gases 32 prior to injection into the upgrading well pair. Recovered fluids 44 are subjected to appropriate gas/fluid separation to recover some hydrogen for re-injection.

[0080] The catalyst is preferably a nano-catalyst or ultradispersed catalyst, as described in United States patent 7,897,537. The catalyst may be produced on site by transporting the catalyst precursors to the site, or a pre-manufactured catalyst may be transported to the site. The hydrogen may be initially shipped to the site and produced with small units (hydrogen generators) as the hydrogen pressure and its consumption is much lower than typically needed in conventional surface upgrading, and after production has started, as noted above, the unreacted hydrogen dissolved in the produced oil coming to the surface can be recovered from the distillation process and gas/fluid separation 32.

[0081] In the case where the average residence time of the injected fluids 38 in the upgrading zone is more than 150 hours, upwards of 45% of the heavy oil fractions can be converted to upgraded oil with 14-16° API. After a sufficient residence time, the recovered fluids 44 from the recovery well 18 are introduced into the column 20 for separation. Lighter fraction oil products 20b are removed and residual catalyst, residue

fraction separated from the vacuum/atmospheric residue to recover and recycle the catalyst particles, resulting in upgraded oil 20b with more than 20° API. The recovered fluids 44 are composed of excess hydrogen, upgraded 14-16° API oil, unconverted bitumen and atmospheric/vacuum residue, other produced gases (CH₄, H₂S and H₂O from connate water), and catalyst not retained in the upgrading zone.

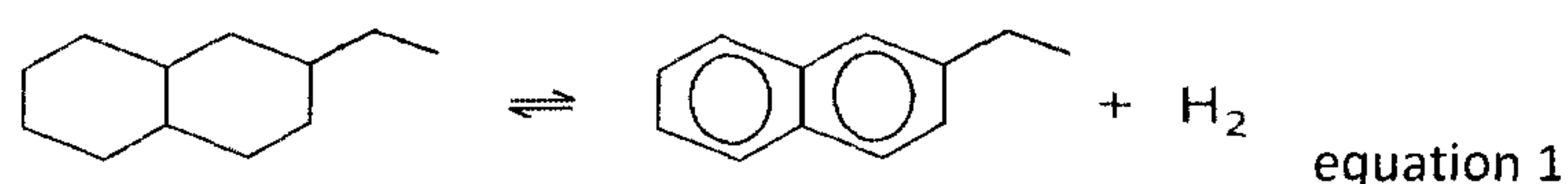
[0082] At the surface, excess hydrogen and other gases 32 are separated and recycled. The remaining recovered liquids 44 are sent to the distillation column 20 for vacuum/atmospheric residue and catalyst recovery. Generally, it is preferred that the upgrading zone 40 retains a proportion of catalyst particles because it minimizes the scope of catalyst recovery and reduces the amount of on-going catalyst injection that occurs, thereby reducing catalyst costs. In the distillation column, diluent 20d may be recovered and recycled to adjacent or other well pairs if desired. Upgraded oil 20b derived from the residue is sent to market. Recovered catalyst and the residue fraction 20a are returned to the upgrading well pair.

[0083] Catalyst will generally be retained in the reservoir until it starts to rise in the recovered fluids and will reach a plateau amount at a concentration lower than the amount being injected. A steady concentration of catalyst will come up to the surface. As the catalyst is heavier (in terms of density) than the heaviest upcoming oil molecules, it will generally remain in the residue during distillation. Entrainment in particles and/or carry-over is unlikely as the distillation columns are generally designed to prevent entrainment and carry-over. However, filters will normally be incorporated downstream of the bottom of the distillation column to retain any large particle in the residue (either sand or agglomerated particles including catalyst that may come up to the surface). Moreover, it is also noted that the heaviest distillates from a vacuum distillation column will generally carry no particles of lighter density carbonaceous material (micro coke particles) that could eventually be entrained by distillation, which indicates that these columns are effective for particle separation. Moreover, the catalyst concentration at injection will be low (less than 1000 ppm in the residue (<0.1% by weight) and it will be substantially lower in the produced fluids; a typical norm BWS (bottom water and sediments) specifies 0.5% wt for example.

[0084] That is, the catalyst particles are effectively separated at the lowest cost from the upgraded produced oil by remaining in the fraction that is recycled to the reservoir. As a

result, the produced lighter oil from the distillation column is generally ready to be transported without containing catalyst particles. In addition, re-injected residue fraction will ultimately be fully converted to lighter fractions and the un-upgradable heaviest fractions will be eventually left back in the reservoir if desired.

[0085] Furthermore, bitumen contains naphthenic molecules that may undergo repeated cycles of dehydrogenation and hydrogenation in the upgrading zone 40. Therefore, naphthenic molecules may contribute to the redistribution of hydrogen to larger residue molecules, thereby improving residue conversion efficiency as per the following chemical equation:



Upgrading and Recovery Chamber

[0086] The RAISCUP process also results in recovery of bitumen from the formation hosting the upgrading well pair. As shown in Figures 2, 3 and 4, the upgrading/recovery chamber 12 generally includes two zones namely the upgrading zone 40 and the recovery zone 42. The upgrading zone is generally the interwell zone 50 through which the injected fluids flow. It is generally maintained at around 350°C by the heat of the upgrading reaction.

[0087] Above the upgrading zone is the recovery zone. As shown in Figure 3, heat from the upgrading zone 40 is transferred by conduction and warms surrounding bitumen, reducing its viscosity. Very hot hydrocarbon vapors, produced by the upgrading reaction, and augmented by diluent and distillate recycling from the surface if needed, rise into the recovery zone, transferring additional heat by convection. The hot hydrocarbon vapors dissolve into the formation bitumen and further reduce the viscosity of the formation bitumen. Gravity drainage, supported by the displacement of rising gases 52, including hydrogen, hydrocarbon vapors, water vapor, and other gases, mobilizes and recovers bitumen 54 through the recovery well. This process results in the upgrading of bitumen produced by adjacent well pairs as well as recovery and upgrading of bitumen from the upgrading well pair. In the upgrading well pair, preferably no steam is injected but hydrogen can be. Hence, bitumen is recovered through vapor extraction, gravity

drainage and gas displacement along with a much lower contribution to recovery (with respect to SAGD) of steam from connate water.

Start Up

[0088] To start the RAISUP or RAISCUP processes, in one embodiment two horizontal wells are drilled, vertically spaced approximately 5 m apart, with the length of the horizontal section subject to optimization. A longer length will generally increase the daily rate of bitumen and residue upgrading. At a temperature of 350°C, up to 1000 barrels (~160 m³) per day per 100 m of well length comprising 50% bitumen and 50% residue can be injected. For example, 5000 barrels per day of bitumen could flow through a 1000 m long upgrading well pair, providing enough capacity to upgrade bitumen produced by 3 to 4 adjacent SAGD well pairs each producing 500 to 1000 barrels per day, as well as recycled residue fraction.

[0089] As noted, the wells are optionally/preferably preheated by the recirculation of steam or hot oil inside the wells. As is known, during steam pre-heating it will typically take approximately 4 months to establish hot fluids communication between the wells wherein the interwell region 50 should reach a temperature of approximately 160°C. Alternatively to steam injection as noted above, a low viscosity oil (vacuum gas oil, VGO) at about 300°C can be recirculated inside the wells to establish hot fluids communication between the wells wherein the interwell region 50 should reach a temperature of approximately 160° C. As noted above, this procedure can eliminate the use of steam and water treatment needs, however it requires a certain storage capacity for startup VGO. That is, a volume higher than the volume of the well bores being heated would be required depending on the use (or not) of VGO for the next phase.

[0090] After the preheat phase, low viscosity oil at 350°C (i.e. atmospheric residue or VGO used during preheating) is injected and circulated using the top well for injection, and the bottom well for recovery. The injected oil is saturated with hydrogen and nano-catalysts to protect it from coking. When the temperature of the interwell region reaches approximately 250°C, bitumen is injected in place of low viscosity oil. The purpose of this phase is to heat the interwell zone to the desired upgrading temperature of 350°C.

[0091] At the same time, the volume of hydrogen in the injection fluid is gradually increased until excess hydrogen conditions required for effective upgrading are reached,

increasing the fractional volume occupied by gas in the well pair and in the interwell pore space.

[0092] The injection pressure is typically limited to the range 2,000-3500 kPa (~300-500 psi) to remain below formation fracture pressure and ensure gas containment for most oil sands reservoirs. Obviously for deeper reservoirs the injection pressure to be used needs to be higher and this would further increase the efficiency of the *in situ* upgrading process of the invention.

Steady State Operations

[0093] Once an interwell temperature of 350°C is reached, injection of bitumen and vacuum residue with hydrogen and hydrocracking catalysts commences.

[0094] Surface hydrocracking catalysts generally operate at high residue conversion rates, as high as 90%, and consume 200-250 standard m³ of hydrogen per m³ of residue, with inlet hydrogen concentrations at an excess of approximately 3 times the consumption rate (~650 standard m³ of hydrogen per m³ of residue). The upgrading conditions outlined are for a 50% residue conversion, requiring hydrogen consumption of only 40-60 standard m³ of hydrogen per m³ of residue. Injected hydrogen is also estimated at 3 times the consumption rate, or 150 standard m³ of hydrogen per m³ of bitumen. Hydrogen injection in the process of the invention can be injected all at once with the catalyst containing residue, or split into two fractions wherein typically about 1/3 of the total injected with the residue and 2/3 bubbling from a liner that would be attached at the top of the producing well in order to enrich the upgrading zone with bubbling hydrogen.

[0095] Ideally, hydrogen partial pressure is maintained higher than 2,500 kPa (360 psi) for effective reaction kinetics. The excess hydrogen conditions described above will ensure sufficient hydrogen partial pressure in the injection well, the upgrading zone and the production fluids.

[0096] At injection conditions of 350°C and 3,450 kPa, gas volumes are reduced by approximately 15 times from standard conditions. In addition, 5 to 10% of the injected hydrogen volume is expected to dissolve in oil. Thus, assuming that the mixture will flow as a dispersion of gas in the oil (i.e. a bubbling regime) or in a mixed bubbling-slug flow regime, then the gas holdup fraction will be around the same as the flowing fraction of

oil. Therefore, the fractional volume occupied by gas in the injection well will be 50% or lower.

[0097] In the upgrading zone, approximately one third of injected hydrogen is consumed. Other gases are produced by various mechanisms (particularly: methane, oil vapors, steam from connate water and hydrogen sulphide). Therefore, the fractional gas volume can be expected to increase through the upgrading zone. The fractional gas volume in the interwell upgrading zone will be higher than 25%.

[0098] The gas to liquids ratio in the production well is also expected to be similar to the conditions in the injection well.

[0099] The shape of the upgrading and recovery chamber 12 is expected to be a more elliptical shape than a conic shape as in SAGD processes. Given that vertical permeability is generally only 0.2 to 0.5 of horizontal permeability within the formation, the lateral dimension of the interwell upgrading zone will normally be greater than the vertical interwell distance. Factors governing the growth rate and shape of the chamber can be assessed by numerical and physical modeling.

[00100] Residence time in the well bores will typically be approximately 1 hour each, but will depend on the flow rate of injected bitumen. However, in the interwell region residence time will depend on factors such as:

- a. Porosity (typically about 30%)
- b. Fractional liquids volume (typically about 75%)
- c. Lateral movement of injected liquids (typically about 5 to 10 m in each direction); and
- d. Flow rate of injected bitumen and atmospheric residue.

[00101] Residence time in the interwell reaction zone will be approximately 50 to 500 hours (typical), matching or exceeding the requirements of the reaction kinetics for the current hydrocracking catalyst as in US Patent 7,897,537.

[00102] The injection rate is a constant volumetric rate but production is generally set to maintain constant pressure in the reaction chamber. Normally, the liquids

production rate will be higher than the injection rate because of oil volume expansion from hydrogen addition and incremental recovery from the upgrading formation.

[00103] Some upgrading will occur in the wells, but most will occur in the upgrading zone. Hydrogen addition upgrading is an exothermic process and can typically increase the oil temperature by approximately 40°C in the reaction zone. This exothermic process more than compensates for local heat losses and maintains the upgrading zone at upgrading temperatures. The heat of hydrocracking reactions ranges from 42 to 50 kJ per mole of hydrogen and is also exothermic.

[00104] The upgrading zone at 350°C will, over time, heat by conduction the surrounding bitumen formation, reducing the viscosity of the surrounding bitumen and making the bitumen mobile. Some of the surrounding bitumen, particularly from zones above the chamber, will flow by gravity through the upgrading zone to the production well and will be replaced by rising hydrogen and produced gas. Therefore, the recovery zone will grow in size from incremental recovery.

[00105] Importantly, during catalytic upgrading processes, as a result of increased chamber temperatures and the upgrading reactions, a greater proportion of the heaviest molecules that would otherwise remain adhered to the formation sand during recovery by conventional methods such as a SAGD process will be mobilized for recovery.

[00106] Upgrading will generate light oil fractions that will rise above the upgrading zone with hydrogen and produced gas. These very hot hydrocarbon vapors will act as solvents and further reduce bitumen viscosity in addition to causing thermal effects. The amount of hydrocarbon vapors available may be augmented by recycling distillates from the column.

[00107] Incremental recovery and chamber growth will be driven by vapor extraction, gravity drainage, and gas displacement. Heat losses and availability of hydrocarbon vapors are two factors that will drive incremental recovery. A typical estimate of bitumen recovery from the upgrading formation is 50 barrels per day per 100 m of well length as known to those skilled in the art.

[00108] Heat losses will be significantly less than typical SAGD heat losses because:

- a. latent heat of hydrocarbons is less than that of steam; in addition, most of the heat transfer will be by conduction which is less effective than convection;
- b. the vapor chamber above the upgrading zone will have light gases (eg. H_2 , CH_4) and condensed water that form an insulation layer between the upgrading zone and the overburden; and,
- c. the vapor chamber size and surface area for heat transfer will be typically less than in a comparable SAGD system.

[00109] Furthermore, gas in the production fluid will provide gas lift, and no water is injected and no typical SAGD chamber is formed. At the end of upgrading or during interrupted upgrading operations, bitumen in the upgrading well pair can be recovered by SAGD (if implemented) due to the presence of the horizontal well pair and pad level steam generation capacity (if implemented).

[00110] Alternatively, the location of the upgrading well pair may be in a neighboring thin bitumen zone that would not be otherwise utilized or recovered.

Mass Balance Considerations

[00111] In considering the mass balance of the system based on typical operating conditions as described above, vacuum residue is injected and circulated through the interwell reaction zone at an oil rate of up to 10 times faster than the flow rate of steam of a typical SAGD process. However, the absence of condensed steam means that the liquids rate is only 2.5 times SAGD.

[00112] Hydrogen injected at three times excess over consumption requirements ensures sufficient hydrogen partial pressure (2600 kPa) for effective reaction kinetics. Hydrogen incorporation gradually reduces hydrogen concentration and volume by up to one third. Excess hydrogen conditions and production of other gases offset hydrogen consumption and maintain fractional gas volume at approximately 90%.

[00113] Injected catalyst flows with the injected oil. Some catalyst particles will be deposited on sand in the upgrading zone while some exit with produced fluids.

[00114] Bitumen made mobile by vapor extraction, heat losses and gas displacement flows downward under the effect of gravity. Hydrogen, light hydrocarbon vapors and other gases (CH_4 , H_2S and steam from connate water) rise into the recovery zone.

[00115] Liquids production is composed of upgraded bitumen and atmospheric residue, swelled by hydrogen addition and recovered bitumen. Therefore, liquids production is greater than liquids injection.

Energy Balance Considerations

[00116] For surface processing, thermal energy is required to heat bitumen to 320°C , operate the distillation column and deliver residue at 320°C (Figure 5). Heat exchangers are deployed to maximize energy efficiency by cooling hot fluids (i.e. upgraded oil being sent to the market) with cold fluids (i.e. incoming bitumen). Further surface energy requirements include:

- a. energy to operate the recycled gas compressor and to re-establish pressure and flow in the recycled gas;
- b. energy for hydrogen production and gas treatment;
- c. energy to compress make up hydrogen to injection pressure if required; and,
- d. heat losses in the injection well.

[00117] The thermal energy supply includes bitumen and atmospheric residue at 300°C being circulated through the upgrading zone. A fraction of the thermal energy contained in the circulating fluid is lost due to formation by conduction and convection (vaporization of light oil fractions). These heat losses heat surrounding bitumen and drive incremental bitumen recovery. Furthermore, upgrading reactions in the reaction zone generate thermal energy that offset heat losses and maintain the reaction zone at the desired temperature of $280\text{-}320^\circ\text{C}$.

[00118] *In situ* thermal energy requirements include maintenance of the upgrading zone at $280\text{-}320^\circ\text{C}$; vaporization of light oil fractions; heating of porous media and

bitumen for mobilization; heating of recovered bitumen to the upgrading temperature; and vaporization of connate water.

Temperature Distribution Considerations

[00119] Figure 4 shows the temperature distribution considerations for the RAISUP and RAISCUP processes. The surrounding formation 56 has a temperature gradient ranging from 10°C closest to the surface to bitumen mobilization temperature (~100°C) near the recovery zone. The recovery zone 42 ranges in temperatures from bitumen mobilization temperature to 300°C. The upgrading zone 40 is typically maintained at a temperature between 280°C and 320°C. Exothermic reactions generate thermal energy and the temperature increases from the heat of the reaction. The temperature is decreased by the flow of colder bitumen from the recovery zone.

[00120] The inlet temperature of the injection well 16 is that of the injected fluids, i.e. approximately 300°C. The outlet temperature of the recovery well 18 is that of the produced fluids, i.e. approximately 280°C.

Surface Process and Facilities

[00121] Figure 5 is a schematic diagram of the layout of potential surface facilities in accordance with the invention. As shown, two well pairs are included with a layout as described by Figure 2A. That is a first well pair 13a is a typical SAGD well pair that is subjected to standard steam injection by steam plant 60. A second well pair 13b is subjected to the RAISCUP process. Fluids recovered from the first well pair can be combined with the fluids from the second well pair.

[00122] Most of the gas stream from the production well (well pair 13b) (after gas/hydrogen separation 74), predominantly excess hydrogen, is recirculated 32 with a purge gas stream 61 sent to gas treatment 62. The purge gas stream 61 is used to control the concentration of produced gas components (i.e. C₁-C₄ gases, H₂S, CO-CO₂) in the recycled gas 32. Water may need to be removed prior to recompression.

[00123] Liquids are sent to the distillation column 20. Upgraded oil 34, with higher than 20° API is sent to the market 34a. Diluent 64a, 64b may be added to the upgraded oil.

[00124] Alternatively, or in addition, distillates/diluent stream 64 can be recovered separately and recycled to the upgrading well pair in order to increase the amount of hydrocarbon vapors available for vapor extraction and control the extent of bitumen recovery. In addition, distillates/diluent may be recovered for sales 64a.

[00125] The distillation column 20 produces residue 26 that was unconverted in the upgrading chamber together with recovered catalyst that was not retained within the upgrading chamber. This residue 26 is recycled to the upgrading well pair through residue conditioning 26a.

[00126] Bitumen 22, from adjacent SAGD well pairs 13a is mixed with residue 26 with hydrogen 28 and catalyst 30. The combined stream is added to recycled gas 32, and injected into the upgrading well pair 13b.

[00127] A heat exchanger may be used to pre-heat the incoming bitumen 22 and diluent 64 with the upgraded oil 34 being sent to the market.

[00128] A recycle gas compressor 68 is required to re-establish appropriate pressure and flow rates in the recycled gas. A compressor for makeup hydrogen may also be required.

Process Control Elements and Improvements

Rate of Bitumen Injection

[00129] The rate of bitumen injection determines the volume upgraded but also the rate of thermal energy addition to the formation. Thermal energy comes from heat losses incurred by bitumen-residue injected at 350°C, but also by heat generated *in situ* by hydrocracking reactions. This variable also determines the rate of light oil fractions available for solvent extraction. Therefore, this variable controls:

- a. the production rate of upgraded oil;
- b. the rate of incremental recovery; and
- c. the growth rate of the reaction chamber.

Location of Injection and Production

[00130] The start-up configuration is injection from the top well and production from the bottom well. However, this configuration can be reversed and cycled to control:

- a. temperature distribution in the reaction chamber;
- b. catalyst distribution;
- c. shape of the reaction chamber; and
- d. the rate of incremental recovery.

Top Injection Well and Bottom Production Well

[00131] After start-up, the conventional configuration for a well pair is a top injection well and a bottom production well because this configuration minimizes the amount of pay zone that is below the production well. As is understood, pay zone below the production well is not recovered as the movement of oil and catalyst from the injection well to the production well follows the direction of gravity. Oil vapors produced in the interwell region are allowed to rise in the recovery zone.

Bottom Injection Well and Top Production Well

[00132] In an alternate embodiment, a bottom injection well and top production well configuration maximizes the temperature of the interwell reaction zone. Formation bitumen that is mobilized from zones above the chamber is at temperatures lower than 350°C because mobilization starts at temperatures as low as 150°C. Excessive incremental bitumen recovery may quench the temperature of the reaction zone. With the top well being the producer, recovered bitumen is produced immediately when it reaches the top producing well and does not cool the interwell region. The temperature of the interwell region may rise higher than the injection temperature because of the heat generated by the upgrading reactions, and a hotter interwell zone maximizes upgrading. Furthermore, hydrogen rises through the interwell reaction zone.

Hydrogen Injection from a Tubing String inside the Bottom Production Well

[00133] Excess hydrogen conditions are specified to ensure that sufficient hydrogen is present throughout the process. However, hydrogen is a very light gas and the amount that may flow down from the top injector to the bottom producer may be less than required. In this event, secondary hydrogen injection can be provided through a

tubing string inserted in the bottom producer, thereby replenishing hydrogen supply in the wellbore surrounding the bottom producer and inside the production well.

Electrical Heating

[00134] In a further embodiment, electrical or other heating technologies may be used to increase the amount of supplied thermal energy if this would result in improved performance.

Shutdown and Restart Strategies

[00135] Unplanned interruption of operations would likely cause liquids to accumulate at the bottom of the vertical well where they could cool and solidify in the event of an extended interruption. Therefore, effective temperature measurement and control is desired throughout both injector and production wells. Prompt injection of VGO during an unplanned interruption of operation would likely avoid adverse consequences and also allows steam replacement as indicated above.

Modeling Results

[00136] Modeling results of the RAISUP and RAISCUP processes show that at 350°C, upwards of 50% of the vacuum residue can be upgraded based on a residence time longer than 16 hours. The resulting recovered and upgraded oil has a specific gravity of 16 API or greater, with a viscosity lower than 200 cP (at 25°C). Table 1 shows mass balance data for a typical catalytic upgrading process with a residence time of less than 24 hours at 50% vacuum residue conversion, with hydrogen consumption of 9 Nm³/bbl and catalyst consumption of 0.10 tpd, excluding catalyst recovery.

Table 1- Mass Balance Data for Catalytic Upgrading Process (Modeled)

Characteristic	Bitumen Product	Upgraded Oil
Volume (bpd)	2625	2690
API gravity	8	16
Viscosity at 40°C (cP)	20,000	225
Sulfur (w%)	5	3
Metal (ppm)	600	20
Asphalt (w%)	16	14
Microcarbon, μC (w%)	11	9
Total Acid Number (mg KOH/g)	5	<1

[00137] Table 2 shows modeled heat balance data for a catalytic upgrading process.

Table 2- Heat Balance Data for Catalytic Upgrading Process (Modeled)

Variable	Vacuum Residue at Start	Recovered Bitumen
Volume (bpd)	2500	1000
Volumetric Flow Rate (m ³ /s)	0.0046	0.00184
Specific Heat Capacity @ 300°C (J/kg°C)	2346.2	1997.104
Average Density (kg/m ³)	1077.8	920
Temperature in (°C)	380	10
Temperature out (°C)	296.6	297.0
Rate of Heat Transfer (W)	970,192.1	-970,192

[00138] Table 3 shows heat balance data for a typical SAGD process for comparison.

Table 3-Heat Balance Data for a Typical SAGD Process

Variable	Bitumen in Typical SAGD Process
Volume (bpd)	1000
Volumetric Flow Rate (m ³ /s)	0.00184
Specific Heat Capacity @ 300°C (J/kg°C)	1997.1
Average Density (kg/m ³)	920
Temperature in (°C)	10
Temperature out (°C)	162.1
Rate of Heat Transfer (W)	-514,274

[00139] Table 4 shows recoverable heat from a modeled catalytic upgrading process.

Table 4-Recoverable Heat from Upgraded Oil in Catalytic Upgrading Process (Modeled)

Variable	Upgraded Oil
----------	--------------

Volume (bpd)	1000
Volumetric Flow Rate (m ³ /s)	0.00184
Specific Heat Capacity @ 300°C (J/kg°C)	1500
Average Density (kg/m ³)	750
Temperature in (°C)	297
Temperature out (°C)	40
Rate of Heat Transfer (W)	532,027.8

Deasphalted Oil Assisted In situ Catalytic Upgrading (DAISCU)

[00140] A variation of the RAISCUP process is a deasphalted oil assisted *in situ* catalytic upgrading process (DAISCU). In this embodiment, and with reference to Figure 6 bitumen 22 recovered from the well pair 13 is subjected to deasphalting processes to create deasphalted oil (DAO) 87 that is used as an upgradable heat carrier for injection and pitch 88a,b wherein a portion of the pitch is used as a fuel (the fuel portion) 88a and another portion (the non-fuel portion) 88b of the pitch is re-mixed with DAO 87 for injection. Generally, the relative proportion of the fuel portion to the non-fuel portion is dependent on the degree of upgrading being achieved wherein the proportion will change as the reservoir is approaching the target temperature in the upgrading zone.

[00141] In DAISCU, initially during the creation of the upgrading chamber, bitumen is mobilized and produced by steam in order to create an incipient upgrading chamber in a manner similar to the start-up of RAISUP. During this stage, water is separated and the produced bitumen is stored in a large tank 82 until enough oil is assured to start a solvent deasphalting operation (SDO) that will produce deasphalted oil (DAO) 87 and pitch 88a, 88b as well as a sufficient increase in the temperature of the DAO to the upgrading reaction temperature of ~320°C.

[00142] More specifically, recovered fluids 22 (containing bitumen and upgraded oil) are introduced into a submicronizer system 80 for creating very small particles of the recovered bitumen. The recovered fluids are then pumped to the storage tank 82 having a sufficient volume to collect and store recovered fluids for subsequent processing. Gas 85 from the storage tank 82 may be subject to gas treatment 62. Upon a suitable volume of recovered fluids having been collected, upgraded oil products 34 (from distillation column 84, between solvent deasphalting unit 86 and tank 82) are collected and delivered to market.

[00143] Heavier fractions 84a, containing substantially heavier fractions, will be introduced into a solvent deasphalting unit 86, which by solvent addition forms a deasphalted oil fraction (DAO) 87 and heavier asphalt/pitch fractions 88a (fuel fraction) and 88b (non-fuel fraction) will depend on the relative progress of the upgrading chamber and upgrading reactions. The fuel portion 88a is delivered to furnace 90 wherein the fuel portion is burned together with recovered gases 62a from gas treatment 62 to heat DAO 87 for injection into well 16.

[00144] The non-fuel portion 88b may be returned to micronizer 80 and storage system 82.

[00145] The heated DAO may be combined with hydrogen 28 and catalyst 30 as described above at injection.

[00146] With reference to Figure 7, the upgrading zone is described in relation to DAISCU processes. The recovery chamber is similar to that of Figures 1, 2, 3 and 4. As shown, both the upper and lower wells enable hydrogen injection and DAO is injected into the upper injection well. The upgrading zone can be generally described as having three regions. In the first region (a), hydrogen, catalysts and DAO are injected at reaction temperature. Generally, the injector well volume will determine a residence time in the order of 0.5 to 3 hours, such that a relative minor degree (approximately 10%) of upgrading will occur.

[00147] The second region (b) extends immediately below the injector well and towards the production well. In a mature well, a significant amount of bitumen has already been produced, thus the zone can be described as having a higher degree of injectivity in comparison to other zones insomuch as flow is enabled between the injector and production wells. As such, injected DAO will predominantly flow downwardly and be upgraded to a significant extent due to the reaction conditions in this zone.

[00148] Bitumen in the region above the injector well flows downwardly as a result of dissolution and convective heat being transferred by volatile hydrocarbon vapors and gases produced during upgrading, by the hydrogen injected but also by overheated steam formed from connate water. All these gases tend to concentrate and reflux at the top of the chamber carrying heat and solvent capabilities to assist in mobilizing bitumen downwards towards the production well. Thus, bitumen from above the injector well is also upgraded with zone (b).

[00149] Bitumen conductively heated by the DAO adjacent the lateral walls of the interwell region is also mobilized and is significantly upgraded as it mixes with the DAO carrying catalysts near the production well and in contact with the hydrogen flow emanating from hydrogen liner(s) externally attached to the upper hemisphere of the production well.

[00150] The third region, zone (c), is located around the production well and provides additional volume and, hence residence time for completing upgrading before the produced oil reaches the surface or the temperature drops below the reaction temperature.

Nano-Catalytic In situ Upgrading (n-CISU)

[00151] In a further embodiment, and with reference to Figure 8, a nano-catalytic *in situ* upgrading (n-CISU) technology is described. The n-CISU process can be applied to a simple well configuration using huff and puff extraction. In this embodiment, a vertical well 13c can be utilized in which hot fluids (i.e. including produced oil) together with other additives including hydrogen 28 and catalyst 30 are pumped into the well. After injection, the well is sealed and pressurized for a soak time to allow in-situ upgrading to occur. After a sufficient soak time, the pressure is released and fluids including upgraded oil 80 is pumped from the well. The cycle can be repeated as long as the well is productive.

[00152] In greater detail, the start-up and production phases may be achieved in the following representative description. Initially, steam 60 is used to preheat the reservoir zone around a vertical well 13 in accordance with normal huff and puff procedures. During this phase, preliminary quantities of oil/bitumen 80 will be produced from the well and stored in a heated tank 82 (T~80-140°C) for later use. Once enough injectivity has been created (if initially non-existent), the stored oil 62a would be used for two purposes, first to disperse nano-catalysts 30 (at an approximate concentration of 600 ppm) in that oil and second to convey heat to the reservoir at a typical injection temperature 270-290°C. Catalyst is injected once in the first injection cycle and in a small quantity. Any additional catalyst can be introduced during successive cycles to maintain catalyst concentration at a desired level. Hydrogen 28 is co-injected with the down-going oil (H_2 /bitumen ratio 90 sm^3 /bitumen or oil m^3).

[00153] The injected material is introduced at a pressure slightly above the reservoir pressure. Once sufficient hot oil has been injected (typically about 90% of the oil initially produced and stored during 10-15 days of initial production), a closed well period (soaking time) between 10 to 15 days is maintained. During the soak time, both the injected oil and the oil being recovered is upgraded.

[00154] During soaking, the pressure and gas composition of the well is monitored to ensure that favorable upgrading conditions are being maintained. Additional hydrogen may be added during the soak time as may be required to maintain reservoir pressure and to promote favorable reaction kinetics.

[00155] Hydrogen is typically consumed at a ratio of 15 sm³ per barrel of oil injected and produced. 45 sm³ of hydrogen per barrel of heated oil/bitumen injected may be consumed as a maximum, assuming oil productivity is doubled with respect to a standard huff and puff dry operation (highest expectation). Thus approximately 25 to 50% of the hydrogen injected would be consumed.

[00156] After the soak period, recovered fluids will be subjected to distillation in distillation column 20 to effect separation of upgraded oil for market 34 and recovery of gas components 85. As in previous embodiments, high viscosity components, including residue, may be re-injected into the well as the cycles are repeated.

[00157] The same general methodology can be applied to each of the well configurations as shown in Figure 2B (injection 1, soak 2 and recovery 3 steps).

Other

Comparison to SAGD

[00158] The methods and apparatus in accordance with the invention can provide significant advantages over SAGD in terms of overall energy balance. As known, in a SAGD operation, heat is injected into the formation in the form of steam and is generally recovered as warm water. As such, at surface, water is heated utilizing significant amounts of fossil fuel energy to create the necessary volumes, pressures and temperature of steam for downhole injection. Specifically, the amount of energy required to heat water to steam requires the energy of the heat of vaporization of water to create steam. While the energy of the heat of vaporization of water is input into the reservoir as the steam condenses to water, the water returns to surface as a contaminated water/mineral/hydrocarbon stream that requires significant treatment prior to being

reheated to steam. Specifically, the mineral contaminants must be removed to prevent scaling in the steam generation equipment, and the hydrocarbon must be separated from the water.

[00159] As is understood, the energy cost of removing mineral/hydrocarbon contaminants from water has an associated energy requirement that is significantly reduced with the subject technology as the volume of water recovered from the formation will be significantly less as generally the only water present in the system will be connate water. After hydrocarbon separation, no additional water treatment may be required.

[00160] As such, the environmental impact of the subject technology is significantly lower as significantly lower volumes of water are required for the process. The elimination of settling ponds could be achieved.

[00161] Furthermore, as the in situ upgrading reactions are exothermic reactions, the requirement for heat input at surface is reduced.

Carbonate Formations and Enhanced Oil Recovery in Conventional Reservoirs

[00162] The technology may also be applied to other formations beyond heavy oil reservoirs including conventional reservoirs that may be declining in production, deeper reservoirs than oil sands which are relatively shallow, and carbonate formations. In particular, as compared to SAGD which can generally only be applied to relatively shallow type reservoirs, the subject methodologies can be applied to other formations as an enhanced oil recovery technique.

[00163] The additional oil recoverable with the hot fluid injection method may be 10 to 30% higher than the one recovered via steam stimulation, which are significantly higher recovery rates than from steam injection technologies. Moreover, the oil produced with the subject technologies can reach transportable level ($\mu < 280$ cPois @ 25°C) for bitumen embedded sands, with minimal to no reduction in permeability of the reservoir and with at least similar recovery of oil.

[00164] As a result, the technologies can lead to the elimination of upgrading facilities to enable transportation and/or diluent needs.

[00165] Although the present invention has been described and illustrated with respect to preferred embodiments and preferred uses thereof, it is not to be so limited since modifications and changes can be made therein which are within the full, intended scope of the invention as understood by those skilled in the art.

CLAIMS

1. A method of upgrading heavy hydrocarbons during hydrocarbon recovery from a heavy hydrocarbon formation comprising the steps of:
 - a) drilling an injection well and recovery well into the heavy hydrocarbon formation;
 - b) creating a hydrocarbon mobilization chamber within the heavy hydrocarbon formation by introducing a hot injection fluid into the injection well so as to promote hydrocarbon mobility to the recovery well;
 - c) recovering heavy hydrocarbons from the recovery well to the surface;
 - d) subjecting the recovered hydrocarbons from step c) to a separation process to form lighter hydrocarbon fractions and heavy residual hydrocarbon fractions;
 - e) introducing a portion or all of the heavy residual hydrocarbon fractions at a temperature and pressure to promote hydrocarbon upgrading reactions in the hydrocarbon mobilization chamber; and
 - f) recovering co-mingled and upgraded hydrocarbons from the recovery well.
2. The method as in claim 1 wherein a portion of the heavy hydrocarbon residual fractions from the separation process is used as a fuel to produce heat to heat the hot injection fluid for upgrading reactions.
3. The method as in claim 1 or 2 further comprising the step of subjecting a portion of the lighter hydrocarbon fractions to additional separation processes for forming additional hydrocarbon fractions.
4. The method as in any one of claims 1-3 wherein step e) includes introducing a catalyst into the injection well to promote catalytic upgrading within the injection well and the hydrocarbon mobilization chamber.
5. The method as in any one of claims 1-4 wherein step e) further includes introducing hydrogen into the injection well to promote upgrading reactions within the hydrocarbon mobilization chamber.
6. A method of upgrading heavy hydrocarbons during hydrocarbon recovery from a heavy hydrocarbon formation comprising the steps of:
 - a) drilling an injection well and recovery well into the heavy hydrocarbon formation;

- b) creating a hydrocarbon mobilization chamber within the heavy hydrocarbon formation by introducing a hot injection fluid into the injection well so as to promote hydrocarbon mobility to the recovery well;
 - c) recovering heavy hydrocarbons from the recovery well to the surface;
 - d) subjecting the recovered hydrocarbons from step c) to a solvent deasphalting separation process to form a deasphalted oil and an asphaltic pitch;
 - e) introducing the deasphalted oil from step d) into the injection well at a temperature and pressure to promote hydrocarbon upgrading reactions in the hydrocarbon mobilization chamber; and
 - f) recovering co-mingled and upgraded hydrocarbons from the recovery well.
7. The method as in claim 6 wherein a portion of the asphaltic pitch is used as a fuel to produce heat to heat the hot injection fluids prior to introduction into the well.
 8. The method as in claim 7 further comprising the step of prior to step d) subjecting the heavy hydrocarbons to a separation process to form a heavy oil fraction and lighter fractions and where at least a portion of the lighter fractions are removed for commercialization.
 9. The method as in any one of claims 6-8 further comprising the step of subjecting hydrocarbons recovered from the recovery well to a submicronizer process to form sub-micron sized particles of the hydrocarbons.
 10. The method as in any one of claims 7-9 further comprising the step of introducing hydrocarbons recovered from the recovery well into a storage tank for subsequent processing.
 11. The method as in claim 10 further comprising the step of recovering and treating gases from the storage tank and wherein treated gases are admixed with the deasphalted oil prior to introduction into a furnace used for heating deasphalted oil.
 12. The method as in any one of claims 6-11 further comprising the step of admixing the deasphalted oil with any one of or a combination of hydrogen and catalyst prior to injection of deasphalted oil into the injection well.
 13. A system for recovery and *in situ* upgrading of heavy hydrocarbons within a heavy hydrocarbon formation comprising:
 - an injection well; and

a recovery well;

the injection well and the recovery well operatively connected to a solvent deasphalting system for recovering a deasphalted oil fraction for mixing with an injection fluid for injection into the injection well.

14. The system as in claim 13 further comprising:

a furnace operatively connected to the solvent deasphalting system for heating deasphalted oil prior to injection into the injection well.

15. The system as in any one of claims 13-14 further comprising:

a storage tank operatively connected to the solvent deasphalting system for storing a volume of recovered hydrocarbons prior to further processing.

16. The system as in claim 15 further comprising:

a separation system operatively connected between the storage tank and solvent deasphalting system for separating recovered hydrocarbons into a heavy oil fraction and lighter fractions and where at least a portion of the lighter fractions are removed for commercialization.

17. The system as in any one of claims 14-16 wherein the solvent deasphalting system further recovers a deasphalted pitch portion and the recovered deasphalted pitch portion is operatively connected to the furnace for use as a fuel.

18. The system as in claim 17 further comprising a submicronizer system operatively connected to the recovery well for forming sub-micron sized particles of the hydrocarbons recovered from the recovery well.

19. The system as in any one of claims 13-18 further comprising a hydrogen system operatively connected to the injection well for injecting hydrogen into the injection well.

20. The method as in any one of claims 1-12 where the injection well and recovery well are a single well.

21. The system as in any one of claims 13-19 where the injection well and recovery well are a single well.

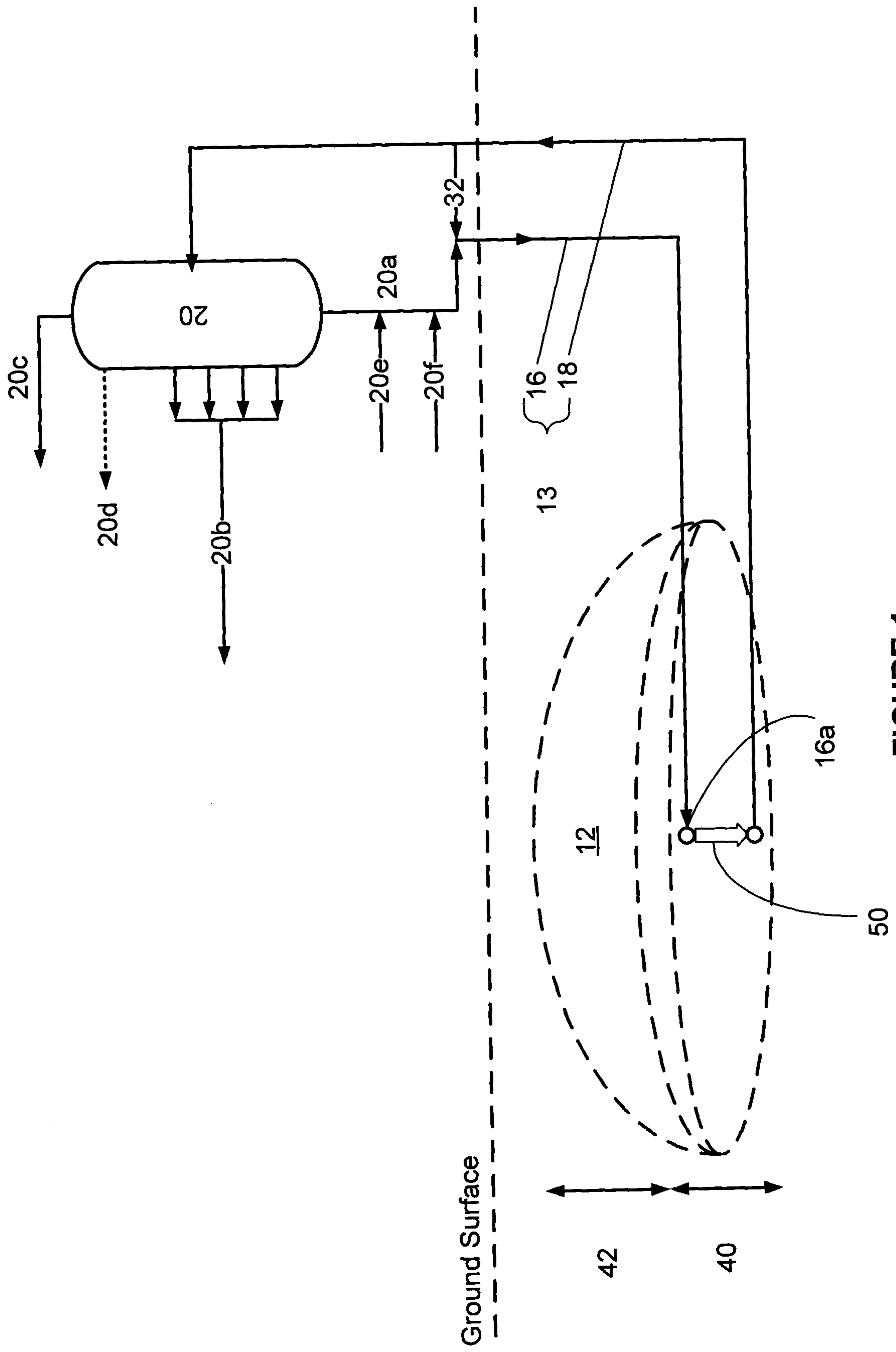


FIGURE 1

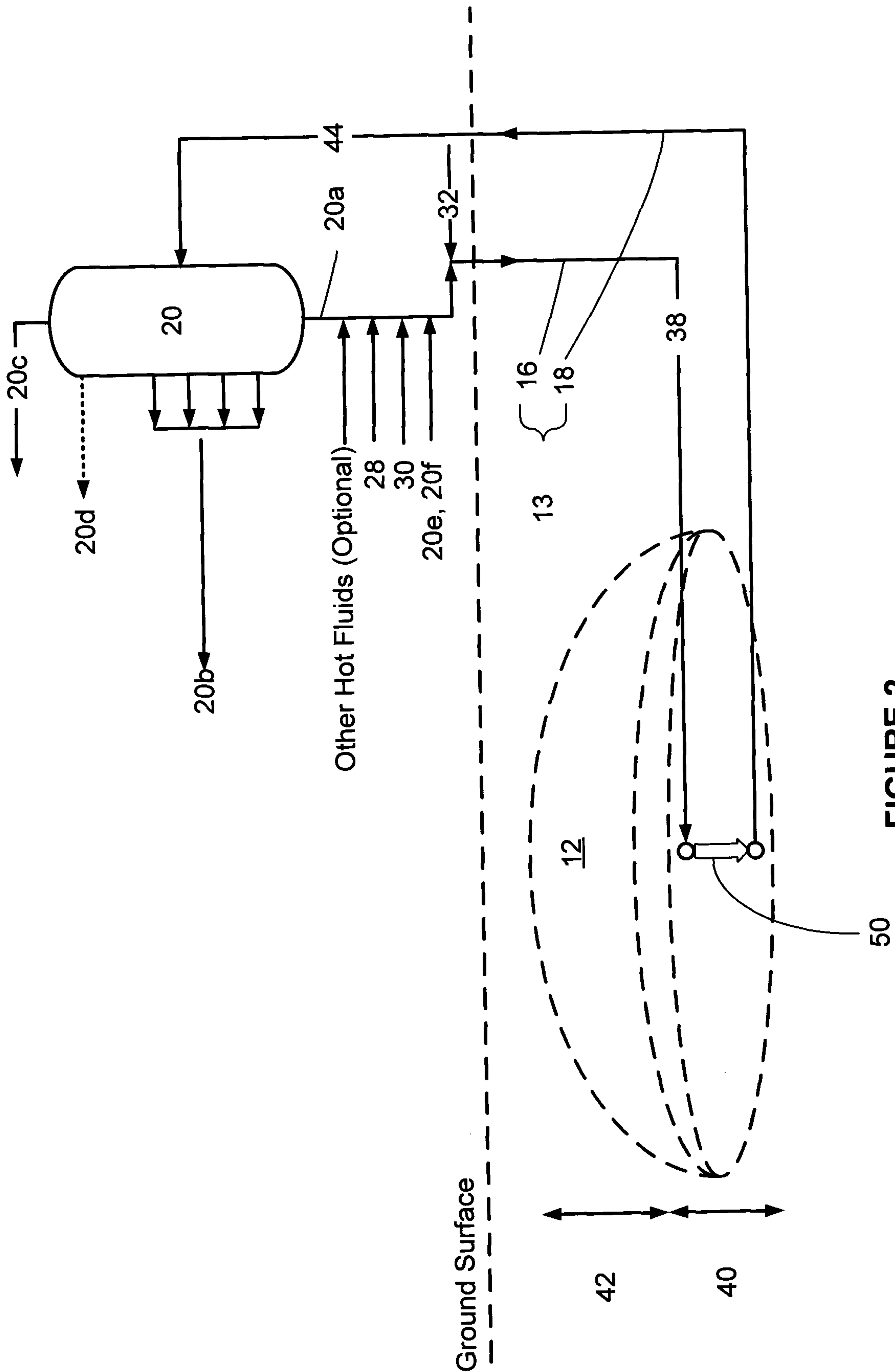


FIGURE 2

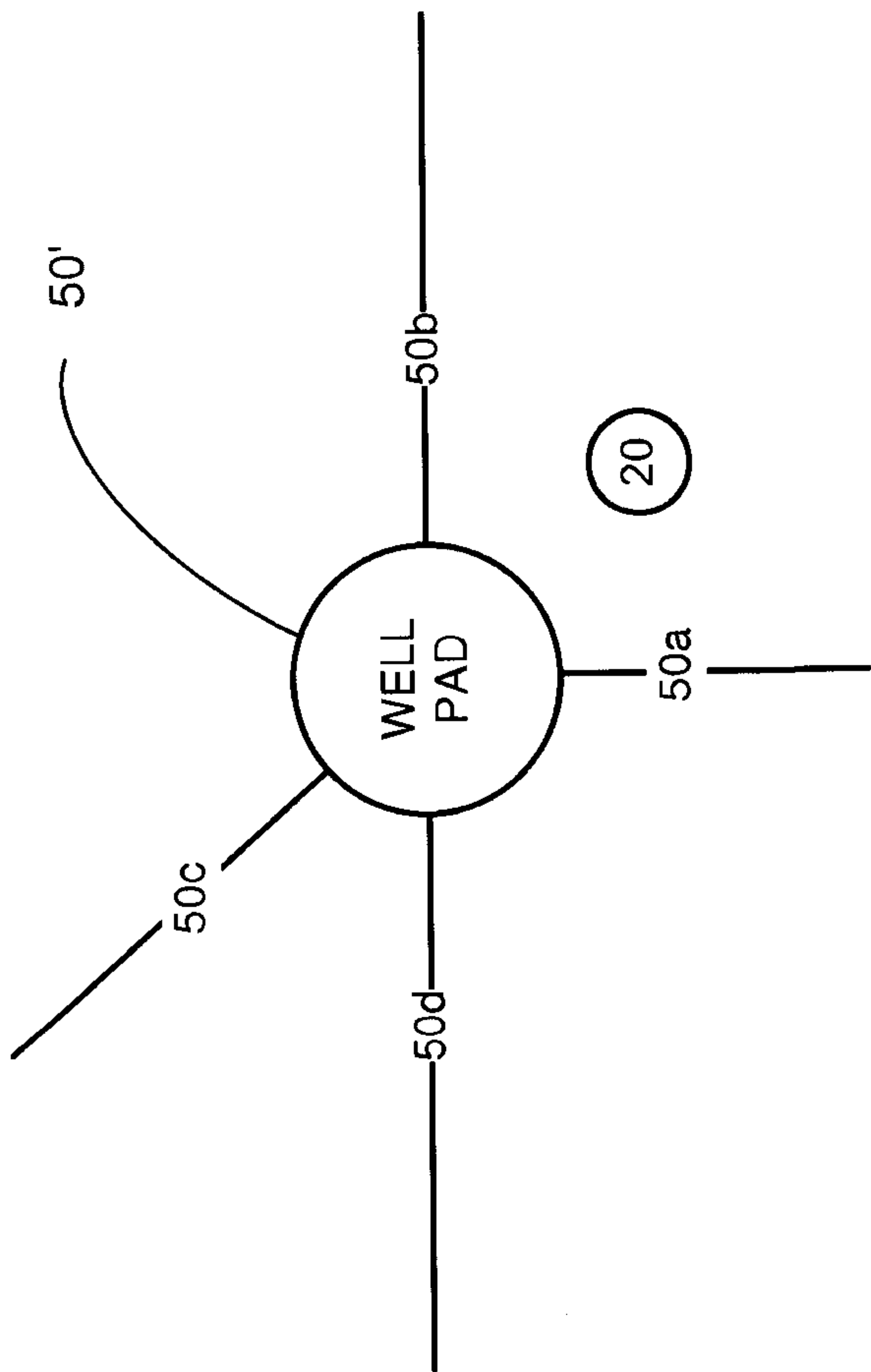


FIGURE 2A

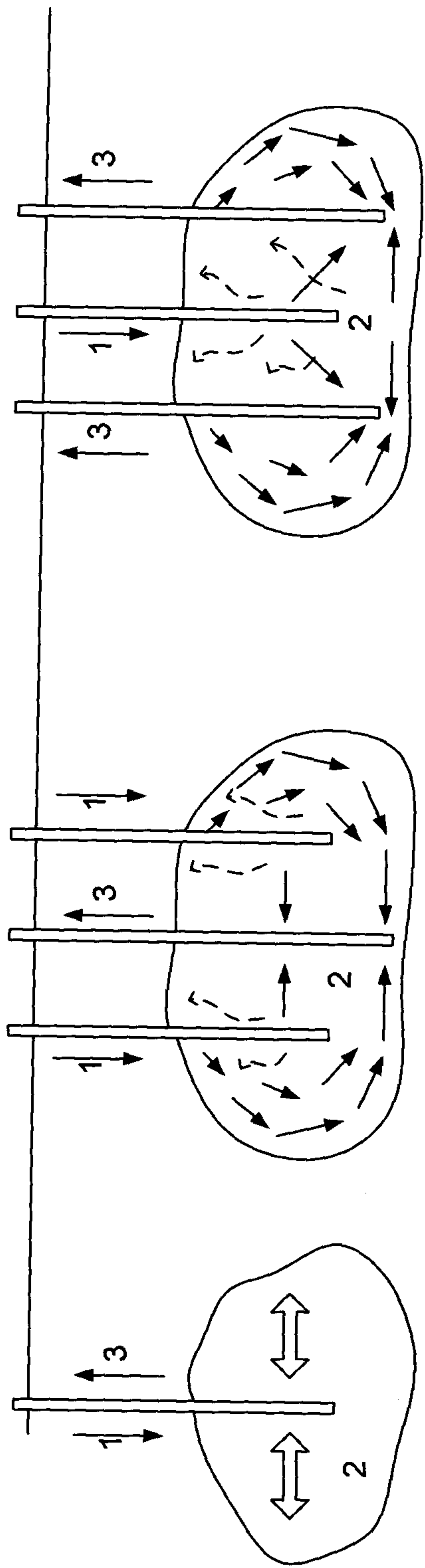


FIGURE 2B

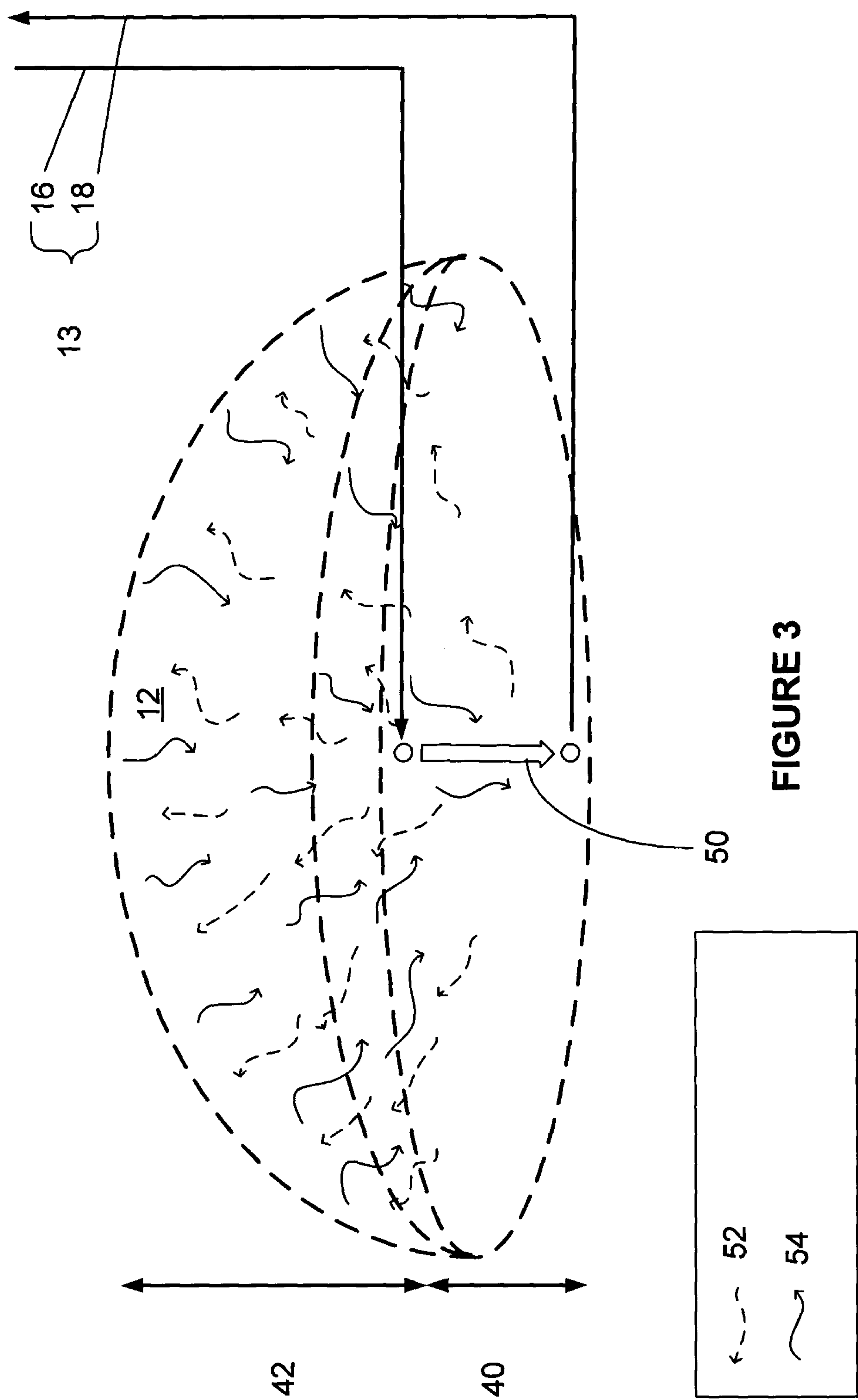
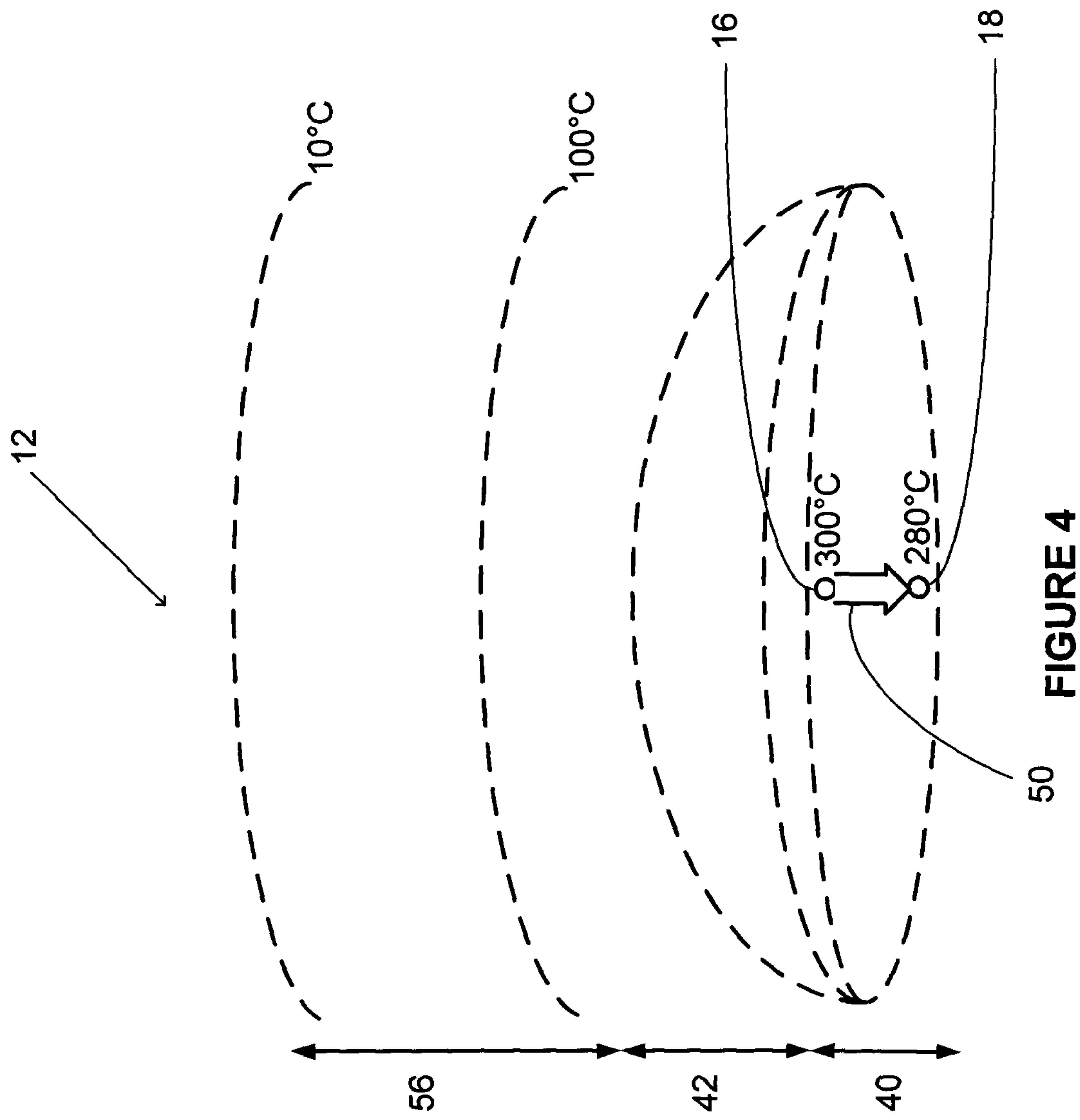
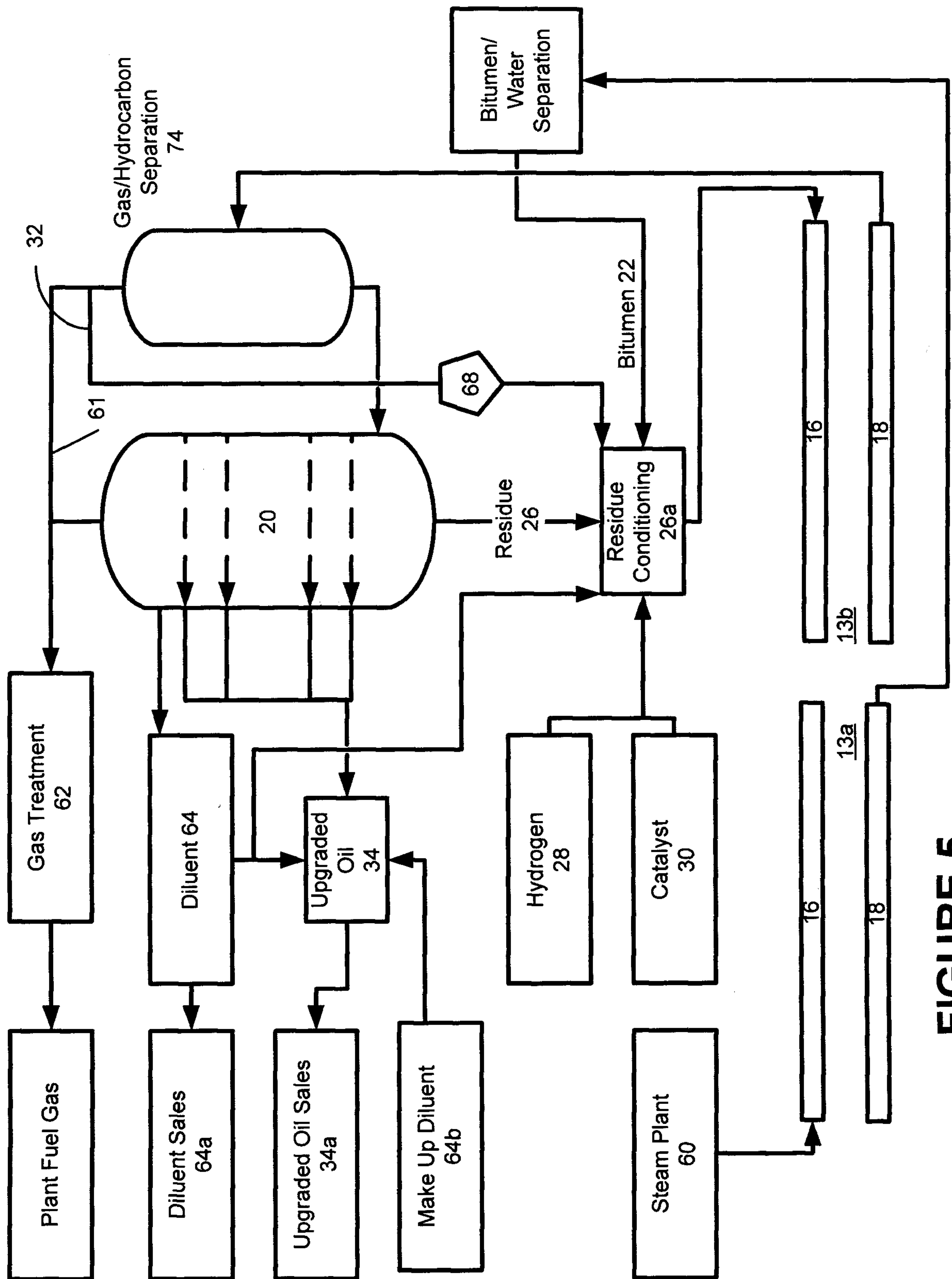


FIGURE 3



**FIGURE 5**

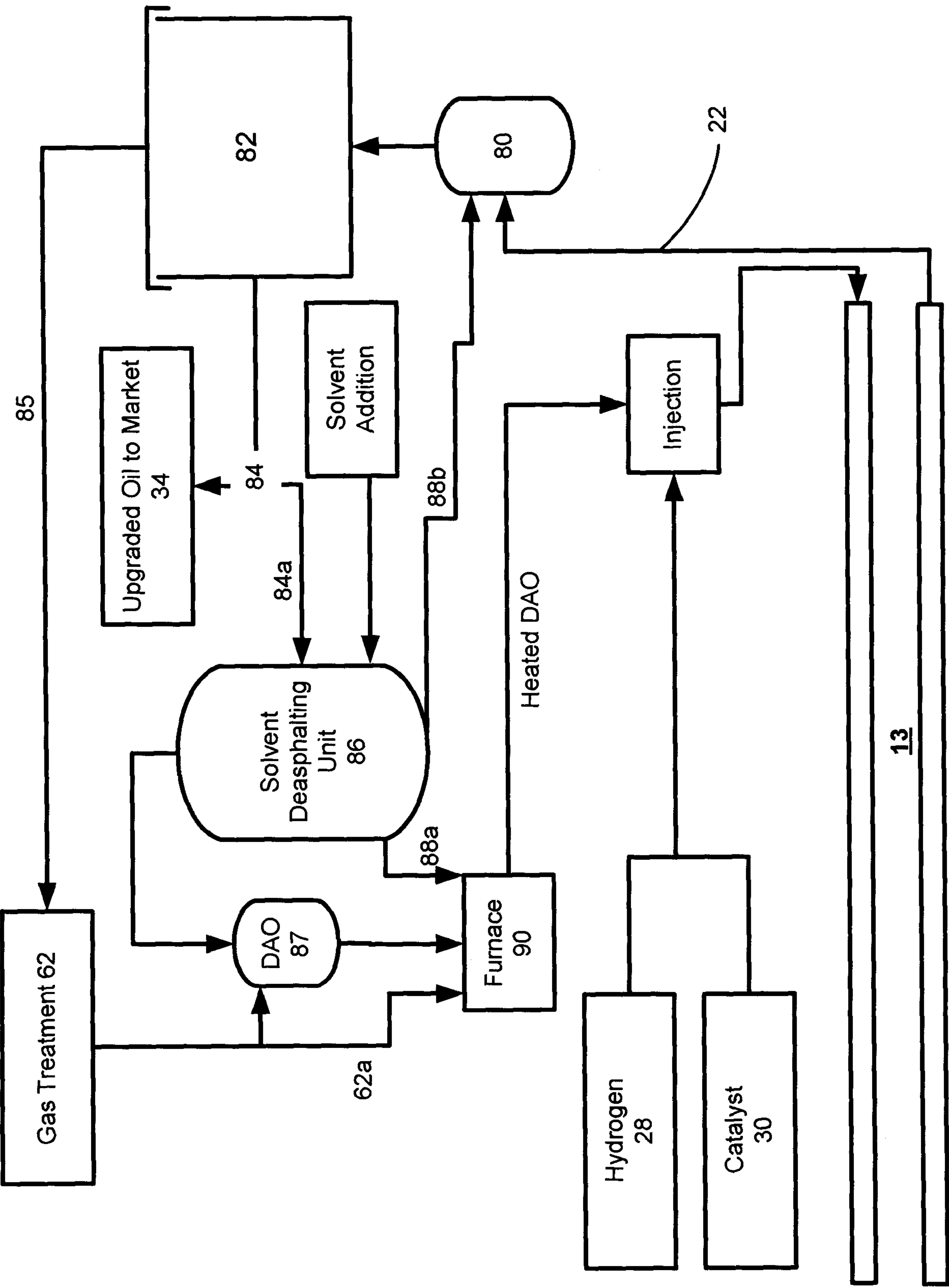


FIGURE 6

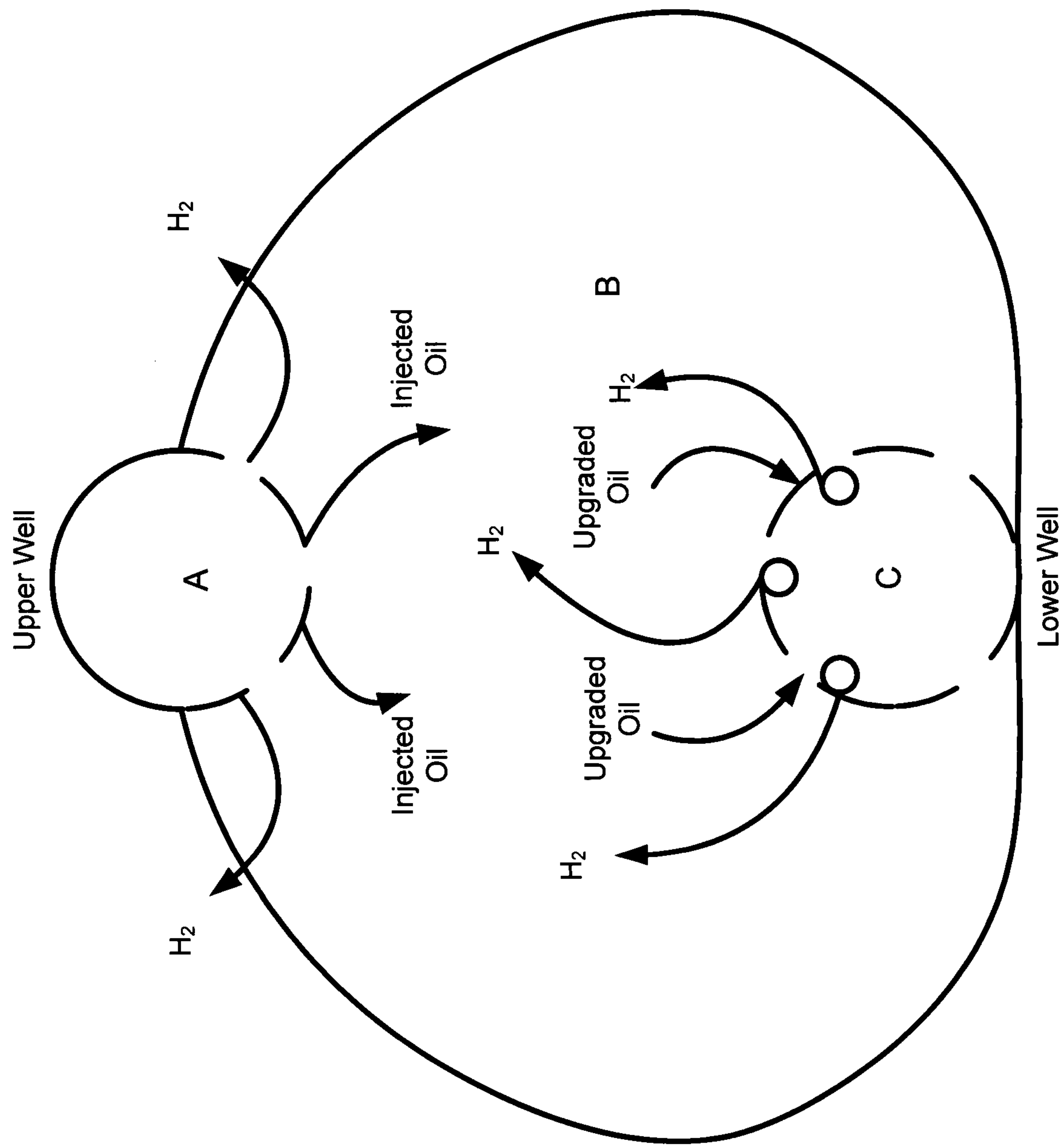


FIGURE 7

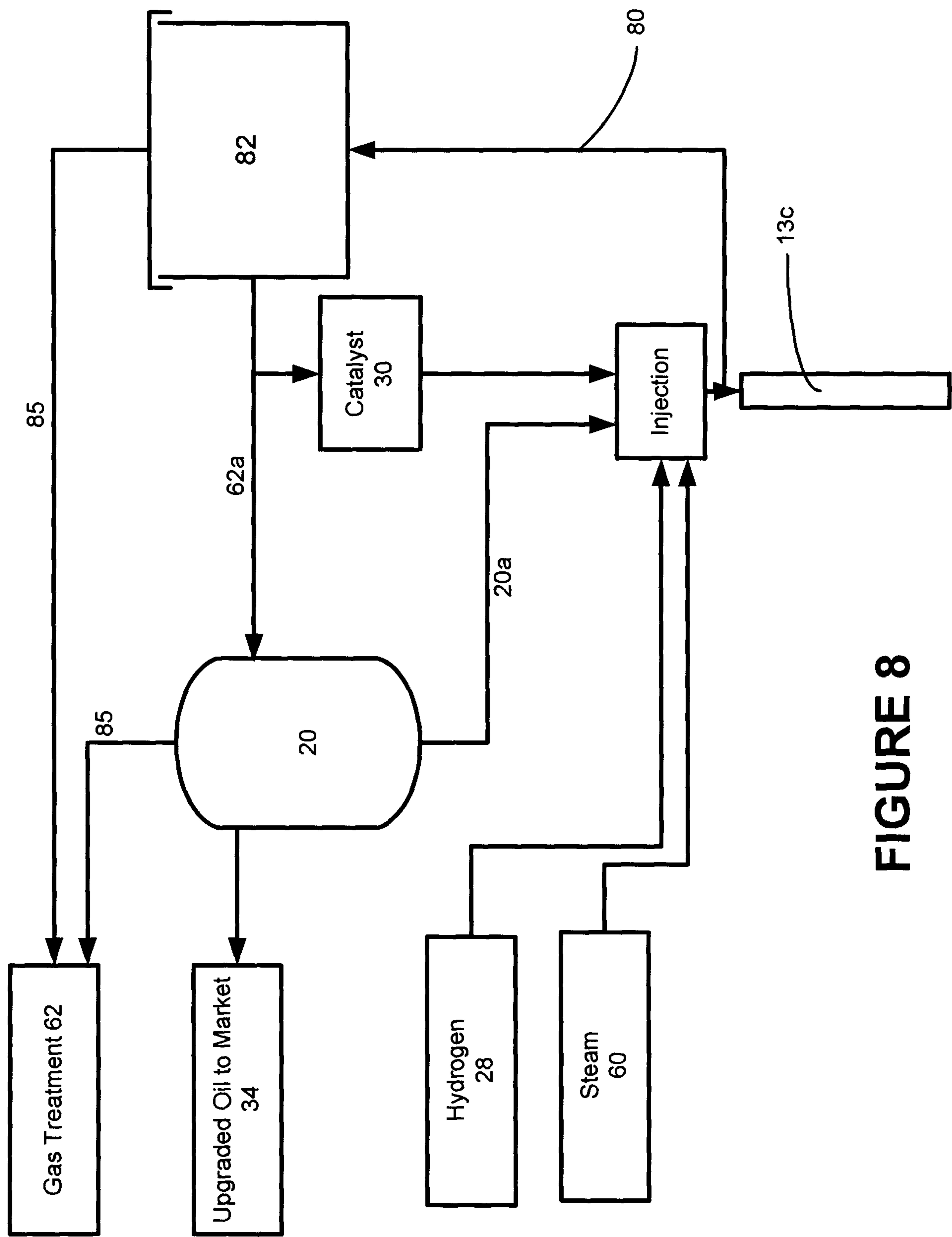


FIGURE 8

