



(12) **DEMANDE DE BREVET CANADIEN
CANADIAN PATENT APPLICATION**

(13) **A1**

(86) Date de dépôt PCT/PCT Filing Date: 2018/03/09
(87) Date publication PCT/PCT Publication Date: 2018/09/13
(85) Entrée phase nationale/National Entry: 2019/09/09
(86) N° demande PCT/PCT Application No.: CA 2018/050283
(87) N° publication PCT/PCT Publication No.: 2018/161173
(30) Priorité/Priority: 2017/03/10 (US62/470,000)

(51) Cl.Int./Int.Cl. *E21B 43/24* (2006.01),
C10G 47/00 (2006.01), *C10G 9/00* (2006.01),
E21B 43/30 (2006.01), *E21B 43/34* (2006.01)
(71) Demandeur/Applicant:
PC-CUPS LTD., CA
(72) Inventeurs/Inventors:
PEREIRA ALMAO, PETRO, CA;
SCOTT, CARLOS EDUARDO, CA;
NGUYEN, THI BICH NGOC, CA
(74) Agent: HICKS & ASSOCIATES

(54) Titre : RECUPERATION ET TRAITEMENT D'HYDROCARBURES LOURDS PAR INJECTION DE FLUIDE A
CONSTITUANTS MULTIPLES
(54) Title: HEAVY HYDROCARBON RECOVERY AND UPGRADING VIA MULTI-COMPONENT FLUID INJECTION

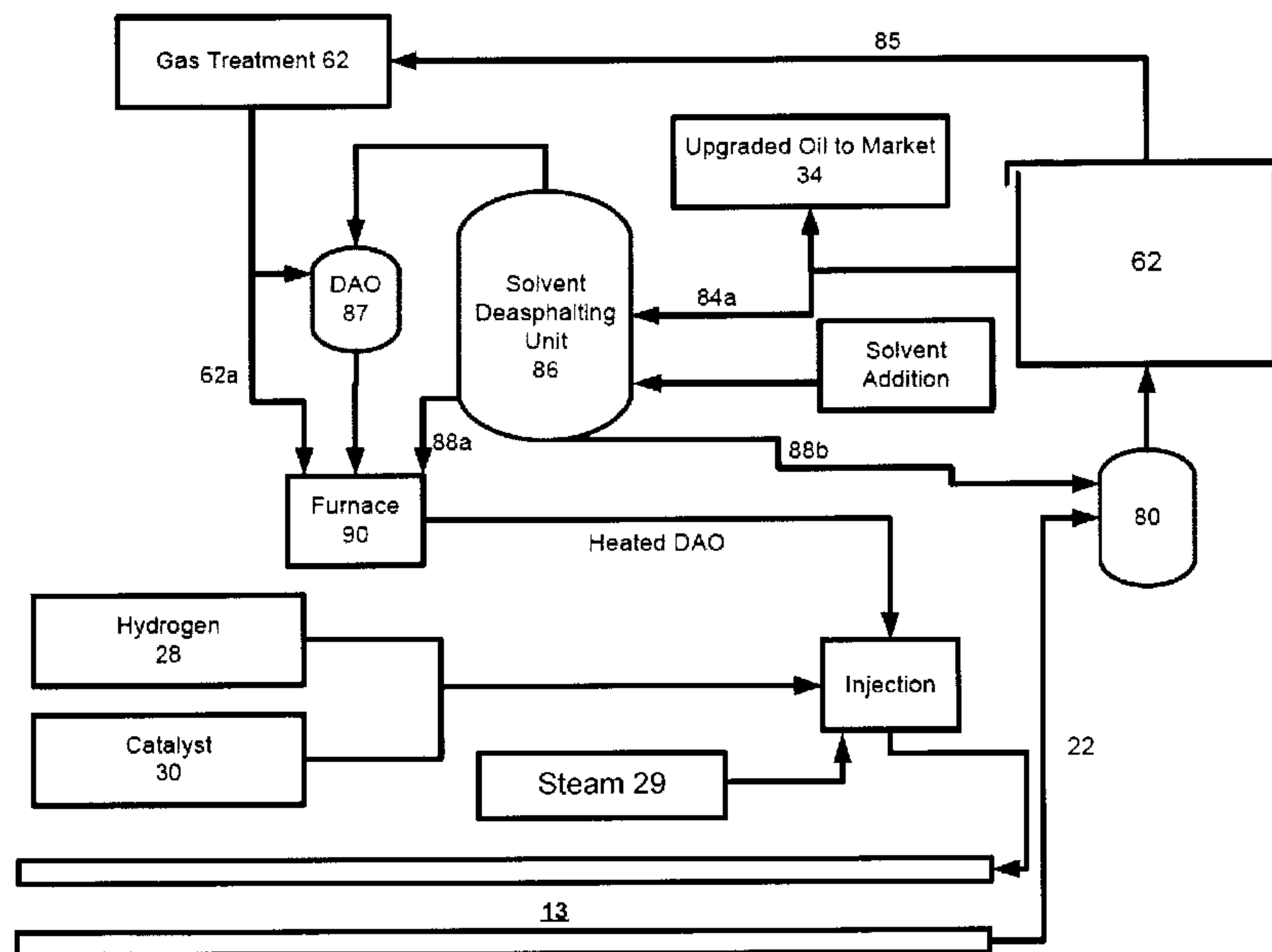


FIGURE 6

(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 steam and a vacuum or atmospheric residue fraction or deasphalted oil into the production well under conditions to promote hydrocarbon upgrading and mobile chamber shaping. 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.

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property
Organization
International Bureau(10) International Publication Number
WO 2018/161173 A1(43) International Publication Date
13 September 2018 (13.09.2018)

(51) International Patent Classification:

E21B 43/24 (2006.01) *E21B 43/30* (2006.01)
C10G 47/00 (2006.01) *E21B 43/34* (2006.01)
C10G 9/00 (2006.01)

SCOTT, Carlos Eduardo; 146 Hidden Valley Green NW,
 Calgary, Alberta T3A 5L8 (CA). **NGUYEN, Thi Bich**
Ngoc; 3307 - 4001 49 Street NW, Calgary, Alberta T3A
 2C9 (CA).

(21) International Application Number:

PCT/CA2018/050283

(74) **Agent: HICKS, Andrew**; Hicks & Associates, 709 Main
 Street, Suite 300, Canmore, Alberta T1W 2B2 (CA).

(22) International Filing Date:

09 March 2018 (09.03.2018)

(81) **Designated States** (*unless otherwise indicated, for every
 kind of national protection available*): AE, AG, AL, AM,
 AO, AT, AU, AZ, BA, BB, BG, BH, BN, BR, BW, BY, BZ,
 CA, CH, CL, CN, CO, CR, CU, CZ, DE, DJ, DK, DM, DO,
 DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, GT, HN,
 HR, HU, ID, IL, IN, IR, IS, JO, JP, KE, KG, KH, KN, KP,
 KR, KW, KZ, LA, LC, LK, LR, LS, LU, LY, MA, MD, ME,
 MG, MK, MN, MW, MX, MY, MZ, NA, NG, NI, NO, NZ,
 OM, PA, PE, PG, PH, PL, PT, QA, RO, RS, RU, RW, SA,
 SC, SD, SE, SG, SK, SL, SM, ST, SV, SY, TH, TJ, TM, TN,
 TR, TT, TZ, UA, UG, US, UZ, VC, VN, ZA, ZM, ZW.

(25) Filing Language:

English

(26) Publication Language:

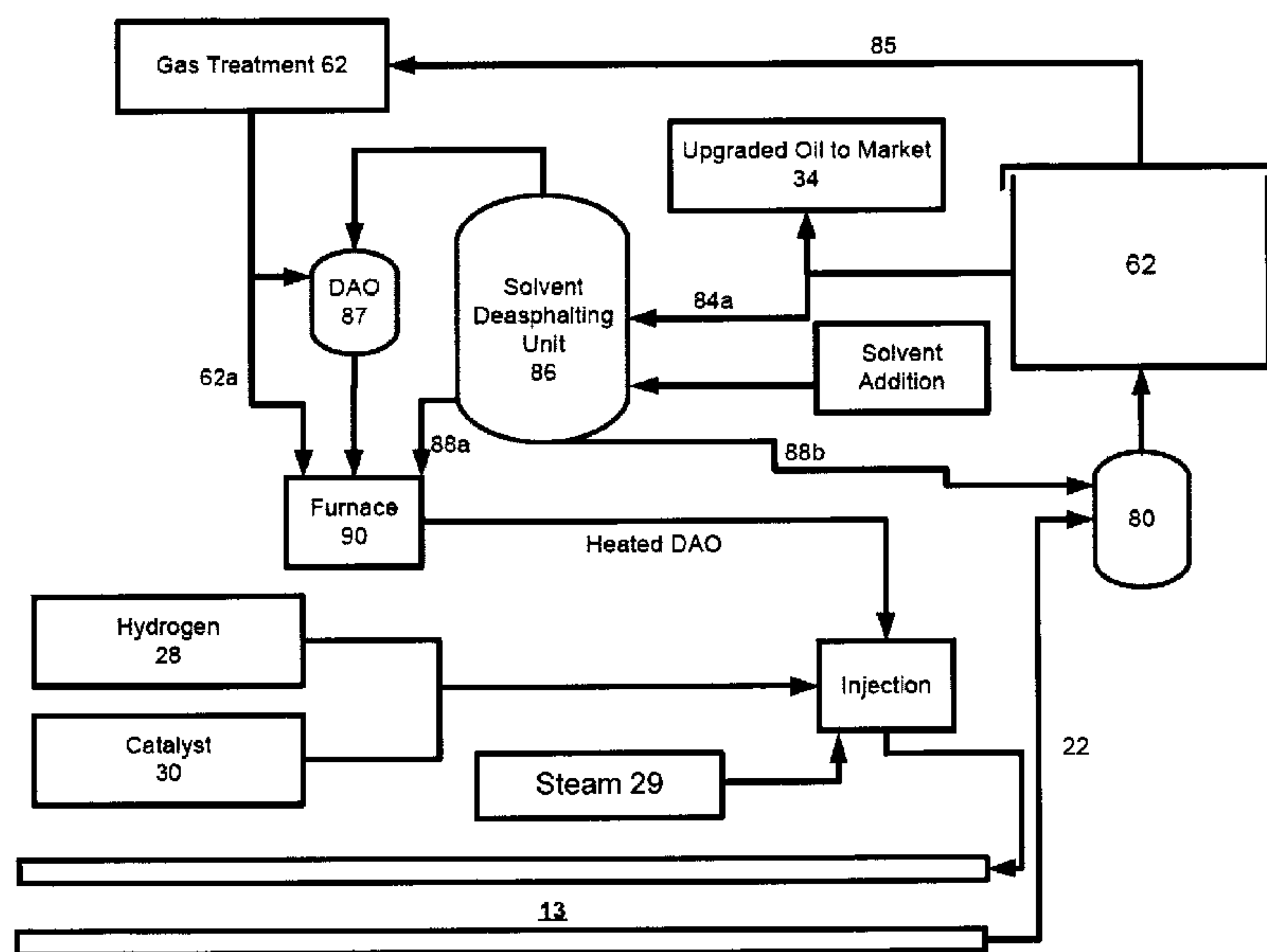
English

(30) Priority Data:

62/470,000 10 March 2017 (10.03.2017) US

(71) **Applicant: PC-CUPS LTD.** [CA/CA]; 1505 15 Ave SW,
 Calgary, Alberta T3C 0Y1 (CA).

(72) **Inventors: PEREIRA ALMAO, Pedro**; 120-69 Spring-
 borough Court SW, Calgary, Alberta T3H 5V5 (CA).

(54) **Title:** HEAVY HYDROCARBON RECOVERY AND UPGRADING VIA MULTI-COMPONENT FLUID INJECTION**FIGURE 6**

(57) **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 steam and a vacuum or atmospheric residue fraction or deasphalted oil into the production well under conditions to promote hydrocarbon upgrading and mobile chamber shaping. 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.

[Continued on next page]

WO 2018/161173 A1

(84) Designated States (*unless otherwise indicated, for every kind of regional protection available*): ARIPO (BW, GH, GM, KE, LR, LS, MW, MZ, NA, RW, SD, SL, ST, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, RU, TJ, TM), European (AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, KM, ML, MR, NE, SN, TD, TG).

Published:

- *with international search report (Art. 21(3))*
- *in black and white; the international application as filed contained color or greyscale and is available for download from PATENTSCOPE*

HEAVY HYDROCARBON RECOVERY AND UPGRADING VIA MULTI-COMPONENT FLUID INJECTION

FIELD OF THE INVENTION

[0001] The invention relates to systems, apparatus and methods for mobilizing heavy hydrocarbons within a reservoir, oil recovery and/or *in-situ* (in reservoir) upgrading of heavy oil and oil sand bitumens.

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 primarily from the cost of building and running a steam plant. In addition, as large amounts of water are required for SAGD.

[0005] Thus, while SAGD processes are effective for heavy hydrocarbon recovery, 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 more 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 effective in promoting upgrading within the reservoir.

[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.

[0012] However, 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. As a result, catalytic upgrading reactions generally require higher temperatures and pressures to be effective.

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 at temperatures generally less than about 200°C. The hot fluids may include paraffins and asphaltenes.

[0019] US 2015/0114636 discloses using 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.

[0020] 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.

[0021] 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

[0022] In accordance with the invention, there is provided systems and methods for shaping a downhole mobilization chamber within a hydrocarbon formation.

[0023] In a first aspect, there is disclosed a method for recovery and in situ upgrading of hydrocarbons in a well having an injection well within a heavy hydrocarbon reservoir, the method comprising the steps of:

- a. introducing a selected quantity of a hot injection fluid including a heavy hydrocarbon fraction and a steam fraction into the injection well to enable: hydrocarbon recovery; and shaping of a downhole mobilization chamber; and
- b. recovering hydrocarbons from the heavy hydrocarbon reservoir.

[0024] The mobilization chamber may be considered to be the downhole region within the reservoir which is mobile (e.g. by being in a liquid phase). For example, a mobilization chamber may be formed by melting solid heavy hydrocarbons. The mobilization chamber may be a reaction chamber in which upgrading reactions occur.

[0025] The method of claim 1, wherein steam and heavy hydrocarbons are co-injected into the reservoir over a period of one or more of: less than 3 months; between three months and 6 months; between 6 months and 1 year; between 1 year and 2 years; between 2 years and 5 years; between 5 years and 10 years; and over 10 years. These time periods may be continuous and/or cumulative (e.g. two separate 3-month periods of co-injection split by a period of pure steam injection may be considered to be a cumulative 6-month period of co-injection).

[0026] The ratio of steam to combined steam and heavy hydrocarbon may be between 0.005 - 0.1 by mass.

[0027] The heavy hydrocarbon reservoir may include a recovery well. The introduction of the hot injection fluid in step a) may take place after connection between the injector well and the recovery well and formation of the downhole mobilization chamber.

[0028] The composition of the hot fluid injected may vary with time.

[0029] During step a) steam and hydrocarbons may be introduced sequentially.

[0030] Steam and hydrocarbons may be alternately introduced over multiple cycles. A cycle may be a time-dependent variation in the hot fluids injected which may be repeated to form multiple cycles. A cycle may comprise a period in which steam is injected without heavy hydrocarbons followed by a period in which heavy hydrocarbons are injected without steam. Another cycle may comprise a period in which steam is injected without heavy hydrocarbons followed by a period in which steam is injected in conjunction with heavy hydrocarbons.

[0031] Steam and hydrocarbons may be introduced simultaneously.

[0032] The injection fluid may include diluent. The injection fluid may include hydrogen. The injection fluid may include catalyst, the catalyst being configured to promote upgrading reactions.

[0033] The temperature and pressure of the injection fluid may be controlled to promote thermal cracking upgrading reactions.

[0034] The injection well and recovery well may be a horizontal well pair.

[0035] Prior to step a), steam may be injected into the horizontal well pair to initiate connection between the injector well and the recovery well and formation of a downhole mobilization chamber.

[0036] The well may have an injection well and a recovery well forming a horizontal well pair.

[0037] The method may include the step of subjecting the hydrocarbons recovered from the recovery well to a separation process wherein heavy and light fractions are separated and wherein the heavy fraction includes a residue fraction.

[0038] The heavy hydrocarbon fraction may be selected from any one of or a combination of shale oil, bitumen, atmospheric residue, vacuum residue, or deasphalted oil.

[0039] The hydrocarbons recovered from the recovery well may be subjected to a separation process wherein heavy and light fractions are separated and wherein the heavy fraction includes a residue fraction.

[0040] The residue fraction from the separation process may be mixed with the injection fluid prior to introduction into the injection well.

[0041] The method may comprise 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.

[0042] The injection fluid may include diluent.

[0043] The temperature and pressure of the injection fluids may be controlled to promote thermal cracking upgrading reactions.

[0044] The temperature of the injection fluid may be 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.

[0045] The temperature and/or pressure of the injection fluids may be controlled such that greater than 30% of residual heavy hydrocarbon of the recovered bitumen is upgraded into lighter fractions.

[0046] The temperature and pressure of the injection fluids may be controlled such the recovered hydrocarbons have a viscosity less than 500 cP at 25°C .

[0047] The recovered hydrocarbons may have a viscosity less than 250 cP at 25°C .

[0048] Prior to step a), steam may be injected into the horizontal well pair to initiate connection between the injector well and the recovery well and formation of a downhole mobilization chamber.

[0049] Prior to step a) the steam may be progressively partially 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.

[0050] The method may include the step of mixing a catalyst into the injection fluid prior to introducing the injection fluid into the injection well.

[0051] The method may comprise the step of mixing hydrogen into the injection fluid prior to introducing the injection fluid into the injection well.

[0052] The temperatures and pressures of the injection fluid may be controlled to promote any one of or a combination of hydrotreating, hydrocracking or steam-cracking reactions.

[0053] The hydrogen may be mixed with the injection fluid to provide excess hydrogen for the upgrading, hydrotreating and/or hydrocracking reactions.

[0054] The hydrogen may be injected along the length of the injection well.

[0055] Approximately 1/3 of the hydrogen may be mixed with the injection fluid at surface and approximately 2/3 may be injected to the reservoir along the horizontal length of the recovery well.

[0056] Hydrogen may be injected from the recovery well via at least one liner operatively configured to the recovery well.

[0057] The catalyst may be any one of or a combination of nano-catalysts or ultradispersed catalyst. The catalyst may comprise micronic particles (e.g. particles with one dimension around 1 micron). The catalyst may have particles with dimensions less than 1 micron and/or less than 120 nm. A nano-catalyst may be considered to comprise catalyst particles which have one dimension less than or equal to 100nm. A nano-catalyst may be considered to comprise solid catalyst particles of which at least 50% by number have one dimension which is less than or equal to 100nm. This can be determined by looking at D50 or median values for the particle size distribution.

[0058] A plurality of adjacent interconnecting well pairs may be 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.

[0059] The heavy hydrocarbon fluids may include any one of or a combination of heavy oil, shale oil, bitumen, atmospheric residue, vacuum residue, or deasphalted oil

[0060] The injection well and recovery well may have vertically overlapping horizontal sections and the injection well is the lower of the injection well and the recovery well.

[0061] The injection well and recovery well may have vertically overlapping horizontal sections and the injection well is the upper of the injection well and the recovery well.

[0062] 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. The hot fluid may comprise heavy hydrocarbons and water/steam.

[0063] A portion of the heavy residual fraction from the separation may be used as a fuel to produce heat to heat the injection fluids for upgrading reactions.

[0064] The method may comprise the step of using a portion of the lighter hydrocarbons to additional separation processes for commercialization.

[0065] Step e) may include introducing a catalyst into the injection well to promote catalytic upgrading within the injection well and the hydrocarbon mobilization chamber and/or step e) may include introducing hydrogen into the injection well to promote upgrading reactions within the hydrocarbon mobilization chamber.

[0066] 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 (e.g. steam) for injection into the injection well.

[0067] The system further may comprise 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.

[0068] 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 comprising heavy hydrocarbons and steam 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 and/or pitch 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. Pitch is the most viscous and heaviest fraction and so may require more upgrading than the deasphalted portion. However, the deasphalted portion may be more reactive in

upgrading reactions. Pitch may comprise 10-20% of raw hydrocarbon or 30% of the vacuum residue portion.

[0069] Asphaltic pitch may be used as a fuel to produce heat to heat the injection fluids for upgrading reactions.

[0070] The method may comprise the step of using a portion of the lighter hydrocarbons to additional separation processes for commercialization.

[0071] The invention may provide 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 (e.g. including steam) for injection into the injection well.

[0072] 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 and steam 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.

[0073] Catalyst and/or hydrogen may be introduced into the well.

[0074] 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 steam and 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

[0075] 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;

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

Figure 9 is a graph showing simulations results of cumulative oil recovery over time for different regimes; and,

Figures 10a-d are simulation results showing the simulated downhole temperature distribution for different regimes.

DETAILED DESCRIPTION OF THE INVENTION

Overview

[0076] The systems, apparatus and methods relate to the recovery of heavy oil in a production well by introducing a hot multi-component fluid into the production well to control the shape of the mobilization chamber. The multi-component fluid includes a heavy hydrocarbon component (e.g. a vacuum or atmospheric residue fraction or deasphalted oil) and a steam component.

[0077] It will be appreciated that, gaseous steam will tend to carry heat towards the top of the mobile reservoir whilst the liquid heavy hydrocarbon component will carry heat laterally from the bottom of the mobile reservoir. The combination of steam and heavy hydrocarbons may therefore grow the mobile reservoir more evenly at the top and bottom of the mobile reservoir thereby expanding the mobile reservoir in all dimensions.

[0078] 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.

[0079] 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 comprising heavy oil and steam. 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 steam and hot residue or deasphalted oil to promote *in situ* upgrading and recovery of the heavy oils and bitumen. Pitch is the most viscous and heaviest fraction and so may require more upgrading than the deasphalted portion. However, the deasphalted portion may be more

reactive in upgrading reactions. Pitch may comprise 10-20% of raw hydrocarbon or 30% of the vacuum residue portion.

[0080] 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.

[0081] 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)

[0082] 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 and/or steam are 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).

[0083] 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, steam and/or other hot fluids. The ratio of steam to combined steam and heavy hydrocarbon in this case is approximately 0.05 (5%) by mass. The hot fluids comprising heavy hydrocarbons and steam may be continuously injected for several years following formation of the mobile chamber between the injection and recovery wells.

[0084] As noted above, the steam component (e.g. 5% by mass of the hot fluid) causes heat to be transferred to the top of the mobile chamber. This encourages the chamber to grow upwards and outwards from the top. In contrast, the more viscous heavy hydrocarbon component causes the mobile chamber to grow downwards and laterally outwards from the bottom. The combination of these effects means that the mobile reservoir grows more evenly top to bottom. It will be appreciated that the water and hydrocarbon components of the hot fluid may be injected sequentially (e.g. in repeated cycles of steam and hydrocarbon) or concurrently.

[0085] In addition, 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.

[0086] 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.

[0087] 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. Under injection conditions, the heat capacity of the injected hot residue is comparable with that of steam (e.g. under certain

conditions, the heat capacity of hot residue may be 90% that of steam under equivalent conditions).

[0088] 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.

[0089] In embodiments described herein, the combination of low-density gaseous steam and higher-density liquid oil may help to shape the mobile chamber by more evenly expanding the chamber laterally away from the injection point. This may improve rates of oil recovery.

[0090] 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 (e.g. thermal cracking), as well as decreasing the viscosity of the bitumen to improve the overall mobility of the bitumen in the reservoir.

[0091] 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 cPoisles @ 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.

[0092] 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 purely steam injection. Accordingly, injecting hot residue can reduce the injection of water into the reservoir, such that the main source of water in the reservoir will be connate water. As a result, water treatment and/or water disposal costs may be reduced.

[0093] During start-up, steam (e.g. with no heavy oil portion) 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 and partially 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 or supplemented by 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.

[0094] 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.

Residue Assisted In-situ Catalytic Upgrading (RAISCUP) Process

[0095] 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.

[0096] 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 2-5 illustrate the top well as the injection well 16 and the bottom well as the recovery well 18.

[0097] 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.

[0098] 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.

[0099] 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.

[0100] During steady-state operation, incoming bitumen 20e and diluent 20f will be blended with hot residue 20a along with steam and 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.

[0101] The catalyst is preferably a nano-catalyst or ultradispersed catalyst, as described in United States patent 7,897,537 incorporated herein by reference. 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.

[0102] 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 32 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, water (e.g. in the form of steam), other produced gases (CH₄, H₂S and H₂O from connate water), and catalyst not retained in the upgrading zone.

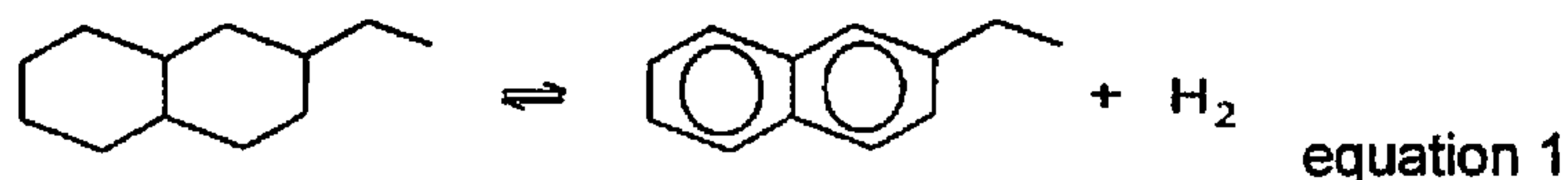
[0103] At the surface, excess hydrogen and other gases 32 are separated and recycled. The remaining recovered liquids 44 are sent to the distillation column 20 for vacuum/atmospheric residue and catalyst recovery. Generally, it is preferred that the upgrading zone 40 retains a proportion of catalyst 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 24 may be recovered and recycled to adjacent or other well pairs if desired. Upgraded oil 34 derived from the residue is sent to market. Recovered catalyst and the residue fraction 20a are returned to the upgrading well pair.

[0104] 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 may come up to the surface if catalyst is not immobilized within the reservoir within a reactor zone adjacent the injection well. That is, it has been observed that in the case of nanocatalysts that such catalysts are immobilized adjacent the injection well within the reservoir pores and, hence, are not transported to the recovery well. If catalyst is returned to 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.

[0105] 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 if catalysts are recovered. 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.

[0106] 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

[0107] 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.

[0108] 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. Steam and 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. 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

[0109] 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) of heavy hydrocarbon per day per 100 m of well length may be injected. In addition, a steam component (e.g. around 1-10% of total injected mass) may be injected with the heavy hydrocarbon portion. The heavy hydrocarbon portion may comprise 50% bitumen and 50% residue. 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.

[0110] 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 reduce the use of steam and water treatment needs compared to SAGD operations, 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.

[0111] After the preheat phase, low viscosity oil at approximately 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 approximately 350°C.

[0112] 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.

[0113] 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

[0114] Once an interwell temperature of approximately 350°C is reached, injection of bitumen and vacuum residue with steam, hydrogen and hydrocracking catalysts commences.

[0115] 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.

[0116] 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.

[0117] 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.

[0118] 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%.

[0119] The gas to liquids ratio in the production well is also expected to be similar to the conditions in the injection well.

[0120] 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.

[0121] 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.

[0122] 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.

[0123] The injection rate is a constant volumetric rate but production is generally set to maintain constant pressure in the mobilization 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.

[0124] 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 consumed hydrogen and is also exothermic.

[0125] 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.

[0126] 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.

[0127] 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.

[0128] 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.

[0129] 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 (e.g. 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.

[0130] Furthermore, gas in the production fluid will provide gas lift, 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).

[0131] 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

[0132] 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.

[0133] 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%.

[0134] 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.

[0135] 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.

[0136] 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

[0137] 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.

[0138] The thermal energy supply includes bitumen and atmospheric residue at approximately 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 280-320°C.

[0139] *In situ* thermal energy requirements include maintenance of the upgrading zone at 280-320°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

[0140] 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.

[0141] 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

[0142] 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.

[0143] Most of the gas stream from the production well, predominantly excess hydrogen, is recirculated 32 with a purge gas stream 60 sent to gas treatment 62. The purge gas stream 60 is used to control the concentration of produced gas components (i.e. C₁-C₄ gases, H₂S, CO-CO₂) in the recycled gas. Water may need to be removed prior to recompression.

[0144] Liquids are sent to the distillation column 20. Upgraded oil 34, with higher than 20° API is sent to the market 34a. Diluent 34b, 64 may be added to the upgraded oil.

[0145] 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.

[0146] 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.

[0147] Bitumen 22, from adjacent SAGD well pairs 13a is mixed with water, residue 26, hydrogen 28 and catalyst 30 as appropriate. The combined stream is added to recycled gas 32, and injected into the upgrading well pair 13b.

[0148] A heat exchanger may be used to pre-heat the incoming bitumen 22 and diluent 24 with the upgraded oil 34 being sent to the market.

[0149] A recycle gas compressor 68 is required to re-establish appropriate pressure and flow rates in the recycled gas. A compressor 28a for makeup hydrogen may also be required.

Process Control Elements and Improvements

Rate of Bitumen Injection

[0150] 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 mobilization chamber.

[0151] 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 mobilization chamber;
- b. catalyst distribution;
- c. shape of the mobilization chamber; and
- d. the rate of incremental recovery.

Top Injection Well and Bottom Production Well

[0152] 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

[0153] In other embodiments, 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

[0154] 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

[0155] 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

[0156] 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 (no steam)

[0157] 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 with no steam (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

[0158] Table 2 shows modeled heat balance data for a catalytic upgrading process.

Table 2- Heat Balance Data for Catalytic Upgrading Process with no steam (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

[0159] 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

[0160] Table 4 shows recoverable heat from a modeled catalytic upgrading process.

Table 4-Recoverable Heat from Upgraded Oil in Catalytic Upgrading Process with no steam (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

Modeling Results (present disclosure with steam)

[0161] In general, simulations indicate that combining steam with heavy hydrocarbon injection can increase the productivity of a well compared with purely SAGD or recovery using purely heavy oil injection. This may apply even to wells which have been operating for some time using purely SAGD or recovery using purely heavy oil injection. That is, converting to a multi-component injection strategy as described herein may lead to an increase in productivity.

[0162] Regarding the simulation results, the well was modelled as follows:

- Model size: 40x10x30 grid cells (1x50x1m)
- Top depth: 200 m
- Porosity: 0.33
- Horizontal Permeability: 3600 mD
- Vertical Permeability: 1800 mD
- PermK=0.5PermX (That is, the vertical Permeability is half that of the horizontal permeability)
- Reservoir pressure: 2000 kPa
- Reservoir temperature: 11 °C
- Oil Saturation, So: 0.81, Water Saturation, Sw=0.19

[0163] Within the well, the well was modelled as having the following composition:

Oil components	Mole fraction
Gases	1.00098E-7
Naphtha	0.041644
Distillate	0.13114
Vacuum gas oil (VGO)	0.32281
Vacuum Residue (VR)	0.5044

[0164] To account for the reactions which may take place within the well, the following kinetic model was used which comprises 14 reactions. Some of the reactions related to reactions of the hydrocarbons found within the well, and others related to reactions of the hydrocarbons introduced into the well.

[0165] Reactions modelled for the hydrocarbons already in the well consisted of:

- $VR + H_2 \rightarrow VGO$
- $VR + H_2 \rightarrow DISTILLATE$
- $VR + H_2 \rightarrow NAPHTHA$
- $VR + H_2 \rightarrow GASES$
- $VGO + H_2 \rightarrow DISTILLATE$
- $VGO + H_2 \rightarrow NAPHTHA$
- $DISTILLATE + H_2 \rightarrow NAPHTHA$

[0166] Reactions modelled for injected oil consisted of:

- $VR_INJ + H_2 \rightarrow VGO_INJ$
- $VR_INJ + H_2 \rightarrow DISTILLATE_INJ$
- $VR_INJ + H_2 \rightarrow NAPHTHA_INJ$
- $VR_INJ + H_2 \rightarrow GASES_INJ$
- $VGO_INJ + H_2 \rightarrow DISTILLATE_INJ$
- $VGO_INJ + H_2 \rightarrow NAPHTHA_INJ$
- $DISTILLATE_INJ + H_2 \rightarrow NAPHTHA_INJ$

[0167] In addition, the simulation takes into account the nature of the injection and recovery wells by placing constraints on the performance and tolerances of the wells.

[0168] The recovery well's constraints are as follows:

- Min BHP (Bottom Hole Pressure): 2200 kPa
- Max surface liquid rate: 400 m³/d
- Min steamtrap: 10°C

[0169] The steam trap (temperature) is the difference in temperature around the producer which is maintained in order to have a negligible loss of live steam. That is, a steam-trap control relates to making a steam process (e.g. SAGD, or other two-well steam arrangements) more thermally efficient by maintaining a liquid pool that surrounds the bottom production well and prevents escape of steam from the steam chamber. In

practice, the continued existence of the liquid pool is monitored by examining the temperature difference (also known as the interwell subcool) between the injected steam and produced fluids. Typically, the subcool is maintained between 20 and 40°C. In this model, the minimum steam trap is set at 10°C. It will be appreciated that there may be a critical steam trap subcool temperature below which the steam trap fails and steam is allowed to exit the producing well.

[0170] The injector's constraints are as follows:

- Max BHP: 2300 kPa
- Max water rate: 80 m³/d
- Injection temperature: 220 C
- Steam quality: 0.9 (In thermodynamics, vapor quality is the mass fraction in a saturated mixture that is vapor. Therefore, Steam quality: 0.9 means that 90 % of the water is gas.)

[0171] Using this model, a variety of hot-fluid injection regimes were simulated. The regimes are differentiated as follows:

- Case 1: SAGD – injecting of steam. This simulation simulated the period starting on January 1, 2008 until the end of simulation (January 1, 2020).
- Case 2: Co-injection steam-catalyst. In particular, this simulation involved:
 - injecting steam (SAGD) for 15 months (starting on January 1, 2008) to expand steam chamber until it reached the top of the formation;
 - then injecting steam, heavy hydrocarbon and catalyst (volume fraction: 0.0495 steam + 0.00793 vacuum residue + 0.94257 H₂) at 350 C until the end of simulation (2020/1/1).
- Case 3: ISUP-only inject catalyst. In particular, this simulation involved:
 - injecting steam (SAGD) for 15 months (starting on January 1, 2008) to expand steam chamber until it reached the top of the formation;
 - then inject heavy hydrocarbon and catalyst (vol. fraction: 0.00793VR + 0.99207H₂) until the end of simulation (January 1, 2020).
- Case 4: Alternate Co-Injection steam-catalyst. In particular, this simulation involved:

- injecting steam (SAGD) for 15 months (starting on January 1, 2008) to expand steam chamber until it reached the top of the formation;
- then alternating 6 months of SAGD and 6 months of Co-injection steam and heavy hydrocarbon and catalyst (using same heavy hydrocarbon fluid as case 2) until the end of simulation (January 1, 2020).
- Case 5: Alternate Co-Injection steam-catalyst. In particular, this simulation involved:
 - injecting steam (SAGD) for 15 months (starting on January 1, 2008) to expand steam chamber until it reached the top of the formation;
 - then alternating 12 months of SAGD and 12 months of Co-injection steam and heavy hydrocarbon and catalyst (using same heavy hydrocarbon/steam injection fluid as case 2) until the end of simulation (January 1, 2020).
- Case 6: Alternate Co-Injection steam-catalyst. In particular, this simulation involved:
 - injecting steam (SAGD) for 15 months (starting on January 1, 2008) to expand steam chamber until it reached the top of the formation;
 - then alternating 24 months of SAGD and 24 months of Co-injection steam and heavy hydrocarbon and catalyst (using same heavy hydrocarbon/steam injection fluid as case 2) until the end of simulation (January 1, 2020).

[0172] It will be appreciated that the first 15 months of each simulation is the same: 15 months of SAGD injection.

[0173] The cumulative oil recovery over time for this well is shown in figure 9 for each of the simulated regimes. As shown in this graph, the SAGD recovery (case 1, 901) is the lowest of the 6 regimes. The next lowest is SAGD initiation followed by pure hydrocarbon injection (case 3, 903). The highest recovery is when the common SAGD initiation is followed by combined steam and heavy hydrocarbon injection (case 2, 902).

[0174] Intermediate between the pure hydrocarbon injection (case 3, 903) and the multi-component steam-hydrocarbon injection (case 2, 902) are the cycled regimes (cases 4-6, 904-906) in which periods of multi-component steam-hydrocarbon injection are

alternated with periods of conventional SAGD injection. As indicated in figure 9, the periods of multi-component steam-hydrocarbon injection correspond to higher production rates, whereas the periods of conventional SAGD injection correspond to slower production (mirroring that of conventional SAGD of case 1, 901).

[0175] To give an indication of the well shaped produced by these regimes, the temperature profile of the reservoir is shown for four of the regimes in figures 10a-d. In each case, the recovery well is located adjacent to left of the profile, one square up from the bottom; and the injection well is located 5 squares directly above the recovery well. In this case, the model is for a horizontal well. In each case, the temperature profile is shown corresponding to June 1, 2012.

[0176] As shown in the profiles, the temperature in the purely SAGD case (figure 10a) rises vertically from the injection well and then is transmitted horizontally when it interacts with the overburden. This causes the cross section to have an upside-down pear shape (the full three-dimensional profile will be this profile reflected in the vertical y-axis and extended along the axis of the horizontal wells which is normal to the plane of the graphs).

[0177] In the other extreme, when only hydrocarbon is injected (after the initial 15 month SAGD phase), the temperature is more concentrated around the injection and recovery wells (as shown in figure 10c). This may be because of the higher density of the heavy hydrocarbon injection fluid with respect to the gaseous steam.

[0178] When both hydrocarbons and steam are injected, there is a much more even vertical distribution of temperature, and the high temperature region extends further in the horizontal direction. In this simulation, in case 4 as shown in figure 10d, the steam appears to be still preferentially heating the top of the reservoir. In contrast, in case 2 as shown in figure 10b, there appears to be a smooth transition between reservoir-top heating and reservoir-bottom heating.

[0179] By allowing a more even vertical distribution of temperature and by allowing the temperature to extend farther horizontally, a larger proportion of the viscous heavy hydrocarbons may be mobilized and extracted from the recovery well.

[0180] Results of this study indicates that:

- Multi-component, steam-hydrocarbon injection is a promising method for improving oil recovery compared to conventional injection methods.
- The incremental oil production may arise from the superior effectiveness in decreasing the viscosity and mass density of heavy-oil.
- The co-steam injection plays an important role to achieve the better performance.
- Multi-component, steam-hydrocarbon may increase oil recovery by 35.81% and reduces the Steam-Oil Ratio (SOR) up to 50% in comparison with the conventional steam injection.
- Simulation results also indicate that a combination of catalysts, hydrogen, and vacuum residue may help to improve the quality of the produced oil.

Deasphalted Oil Assisted In situ Catalytic Upgrading (DAISCU)

[0181] 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) that is used as an upgradable heat carrier for injection and pitch wherein a portion of the pitch is used as a fuel (the fuel portion) and another portion (the non-fuel portion) of the pitch is re-mixed with DAO and steam 29 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.

[0182] 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 62 until enough oil is assured to start a solvent deasphalting operation (SDO) that will produce deasphalted oil (DAO) and pitch as well as a sufficient increase in the temperature of the DAO to the upgrading reaction temperature of ~320°C.

[0183] More specifically, recovered fluids 81 (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 may be subject to gas treatment 62. Upon a suitable volume of

recovered fluids having been collected, upgraded oil products 34 (from distillation column, not shown) are collected and delivered to market.

[0184] 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.

[0185] The non-fuel portion 88b may be returned to micronizer 80 and storage system 84.

[0186] The heated DAO may be combined with hydrogen 28 and catalyst 30 as described above at injection.

[0187] 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, steam 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.

[0188] The second region (b) extends 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 inasmuch 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. The steam component of the injection fluid may cause region (b) to extend upwards above the upper well due to the lower density of the steam component.

[0189] 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).

[0190] 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.

[0191] 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)

[0192] 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 and steam) 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.

[0193] 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 will be delivered to micronizer 80 will be produced from the well and stored in a heated tank 62 (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 $90 \text{ sm}^3/\text{bitumen or oil m}^3$).

[0194] 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.

[0195] 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.

[0196] Hydrogen is typically consumed at a ratio of 15 sm^3 per barrel of oil injected and produced. 45 sm^3 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.

[0197] 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.

[0198] The same general methodology can be applied to each of the well configurations as shown in Figure 2B.

Other**Typical Injection Regimes**

[0199] Typical injection regimes are shown in the table below:

Parameters/SOR	0.53	0.88	1.13	1.65
H ₂ /VR Ratio	100	100	100	160
Water Fraction	0.00500	0.01797	0.03397	0.05509
Injection rate, Q (m ³ /d)	5,549	5,451	4,997	6,500
Water rate, Q _w (m ³ /d)	28	98	170	358
H ₂ rate, Q _{H2} (m ³ /d)	5,466	5,300	4,779	6,103
VR rate, Q _{VR} (m ³ /d)	55	53	48	39
Injection Temp, C	311	300	302	360
Production BHP, kPa	2,000	2,000	2,055	2,397
Production rate, (m ³ /d)	335	300	322	534
Steam quality	0.95	0.87	0.87	0.94
RF, %	34.38	46.28	81.17	92.11
Chamber Volume, m ³	6,265	23,539	73,851	106,486

[0200] SOR is the Steam Oil Ratio (m³/m³).

[0201] In particular, these regimes were modelled optimize the steam oil ratio (to minimize steam use) whilst maximizing the oil recovery factor (RF%) in the well described above in the Modeling Results section.

[0202] The left-most data column provides the steam oil ratio but does not maximize recovery factor. The right-most data column gives the highest oil recovery factor but uses a higher Steam Oil Ratio. The intermediate data columns show intermediate regimes. It will be appreciated that the user will optimize the regime based on the relative importance of water use and recovery factor.

[0203] The table below shows corresponding values for SAGD optimization in the same well:

Parameters/SOR	2.70	3.04	3.12	3.20
Injection rate, Q_w (m ³ /d)	160	359	442	467
Injection BHP, kPa	2,000	3,383	4,000	4,000
Injection Temp, C	170	210	240	240
Production BHP, kPa	2,000	2,265	2,332	2,249
Production rate, (m ³ /d)	335	300	302	333
Steam quality	0.95	0.95	0.95	0.95
RF, %	51.22	57.69	58.79	59.24
Chamber Volume, m ³	80,852	93,736	96,709	97,214

Comparison to SAGD

[0204] 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.

[0205] As such, the environmental impact of the subject technology is significantly lower as significantly lower volumes of water are required for the process.

[0206] 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

[0207] 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.

[0208] 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 ($\mu < 280$ cPoises @ 25°C) for bitumen embedded sands, with minimal to no reduction in permeability of the reservoir and with at least similar recovery of oil.

[0209] As a result, the technologies can lead to the elimination of upgrading facilities to enable transportation and/or diluent needs.

[0210] 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 for recovery and in situ upgrading of hydrocarbons in a well having an injection well within a heavy hydrocarbon reservoir, the method comprising the steps of:
 - a) introducing a selected quantity of a hot injection fluid including a heavy hydrocarbon fraction and a steam fraction into the injection well to enable: hydrocarbon recovery and shaping of a downhole mobilization chamber within the heavy hydrocarbon reservoir; and
 - b) recovering hydrocarbons from the heavy hydrocarbon reservoir.
2. The method of claim 1, wherein steam and heavy hydrocarbons are co-injected into the reservoir over a period of at least 6 months.
3. The method according to any of claims 1-2, wherein the ratio of steam to combined steam and heavy hydrocarbon is 0.005 - 0.1 by mass .
4. The method according to any of claims 1-3, wherein the heavy hydrocarbon reservoir includes a recovery well, and wherein the introduction of the hot injection fluid in step a) takes place after connection between the injector well and the recovery well and formation of the downhole mobilization chamber.
5. The method according to any of claims 1-4, wherein, during step a) steam and hydrocarbons are introduced sequentially.
6. The method according to any of claims 1-5, wherein steam and hydrocarbons are alternately introduced over multiple cycles.
7. The method according to any of claims 1-4, wherein steam and hydrocarbons are introduced simultaneously.
8. The method according to any of claims 1-7, wherein the injection fluid includes diluent.
9. The method according to any of claims 1-8, wherein the injection fluid includes hydrogen.
10. The method according to any of claims 1-9, wherein the injection fluid includes catalyst, the catalyst being configured to promote upgrading reactions.

11. The method according to any of claims 1-10, wherein the temperature and pressure of the injection fluid is controlled to promote thermal cracking upgrading reactions.
12. The method according to any of claims 1-11, where the injection well and recovery well are a horizontal well pair.
13. The method as in any one of claims 2-12 wherein 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 mobilization chamber.
14. The method according to any of claims 1-13 wherein the well has an injection well and a recovery well forming a horizontal well pair.
15. The method according to any of claims 1-14 wherein the heavy hydrocarbon fraction is selected from any one of or a combination of shale oil, bitumen, atmospheric residue, vacuum residue, or deasphalted oil.
16. The method as in any one of claims 1-15 wherein 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.
17. The method as in any one of claims 1-16 wherein the injection fluid includes diluent.
18. The method as in any one of claims 1-17 wherein the temperature of the injection fluid is controlled to provide a downhole sump temperature of $320\pm 20^{\circ}\text{C}$.
19. The method as in any one of claims 1-18 wherein the downhole residence time of injected fluids is 24-2400 hours.
20. A system for recovery and *in situ* upgrading of heavy hydrocarbons within a heavy hydrocarbon formation comprising:
 - a) an injection well;
 - b) a mixing and hot fluid injection system configured to mix heavy hydrocarbons with additional injection fluids, wherein the additional injection fluids comprise steam, and to inject the mixed fluids into the injection well.

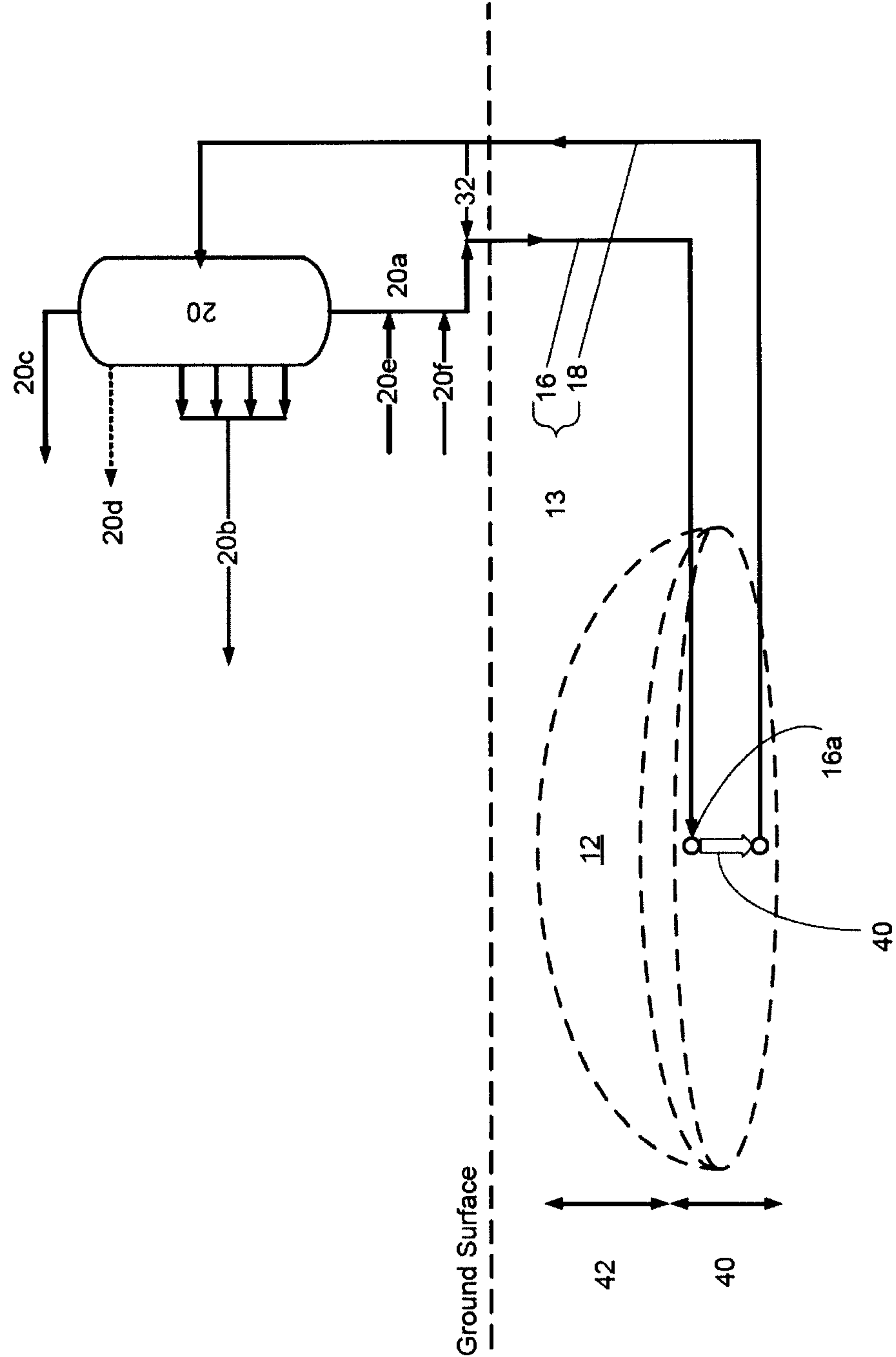
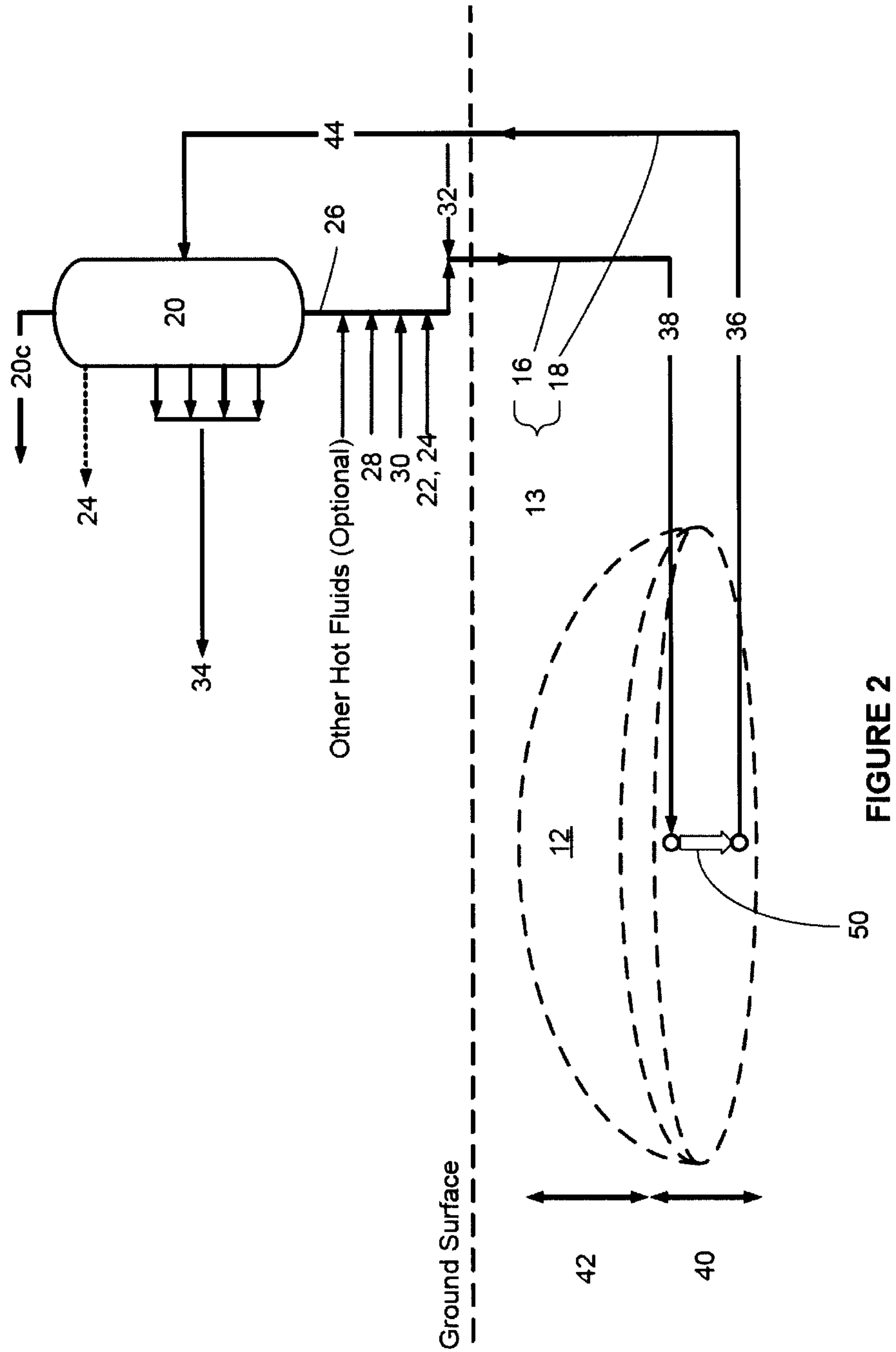


FIGURE 1



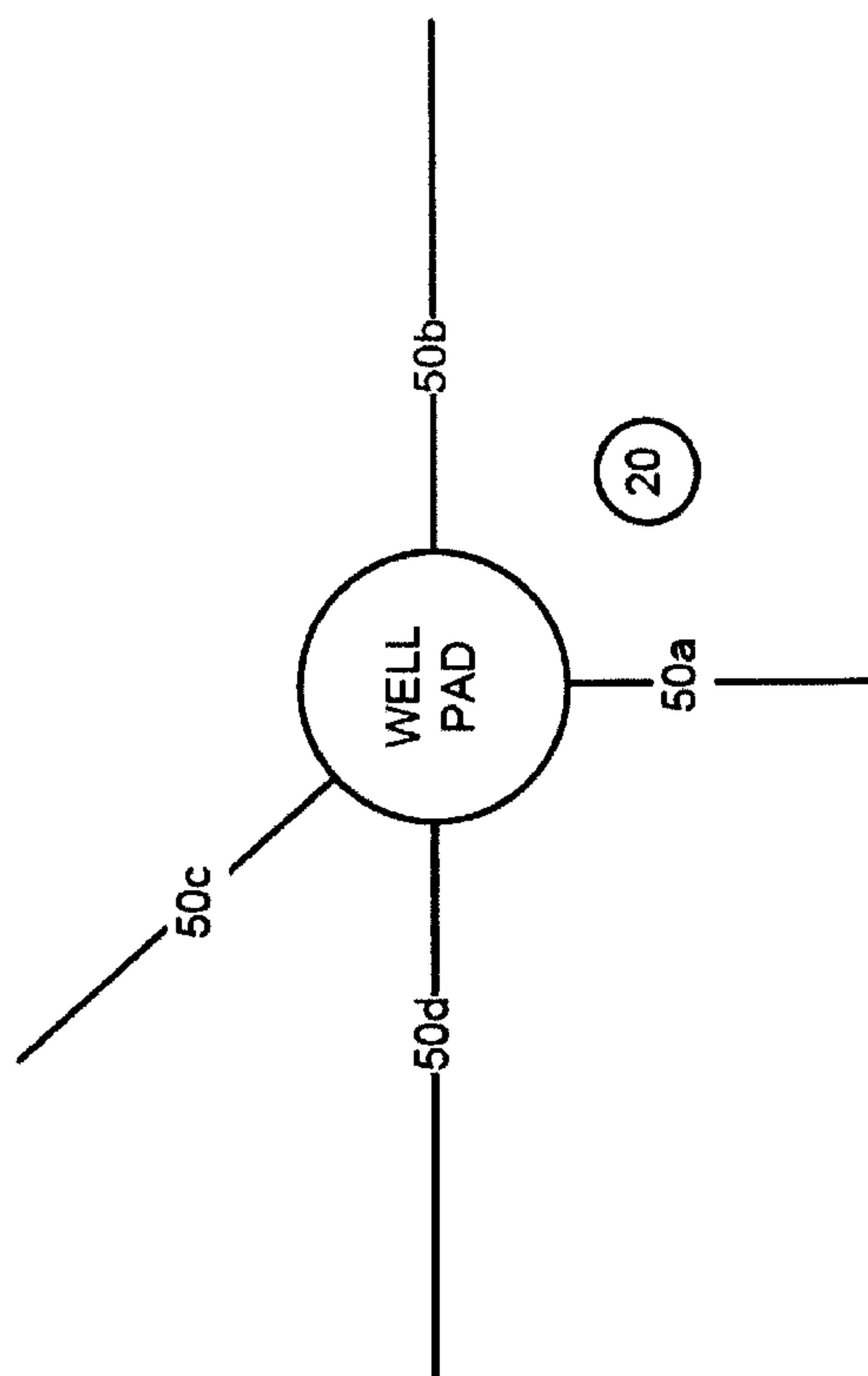


FIGURE 2A

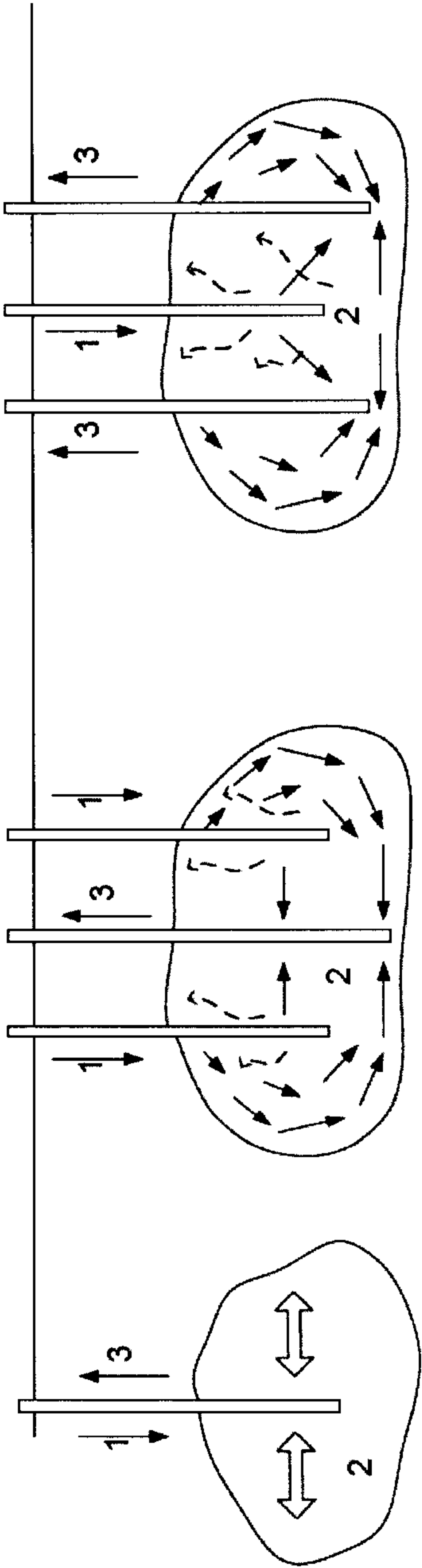


FIGURE 2B

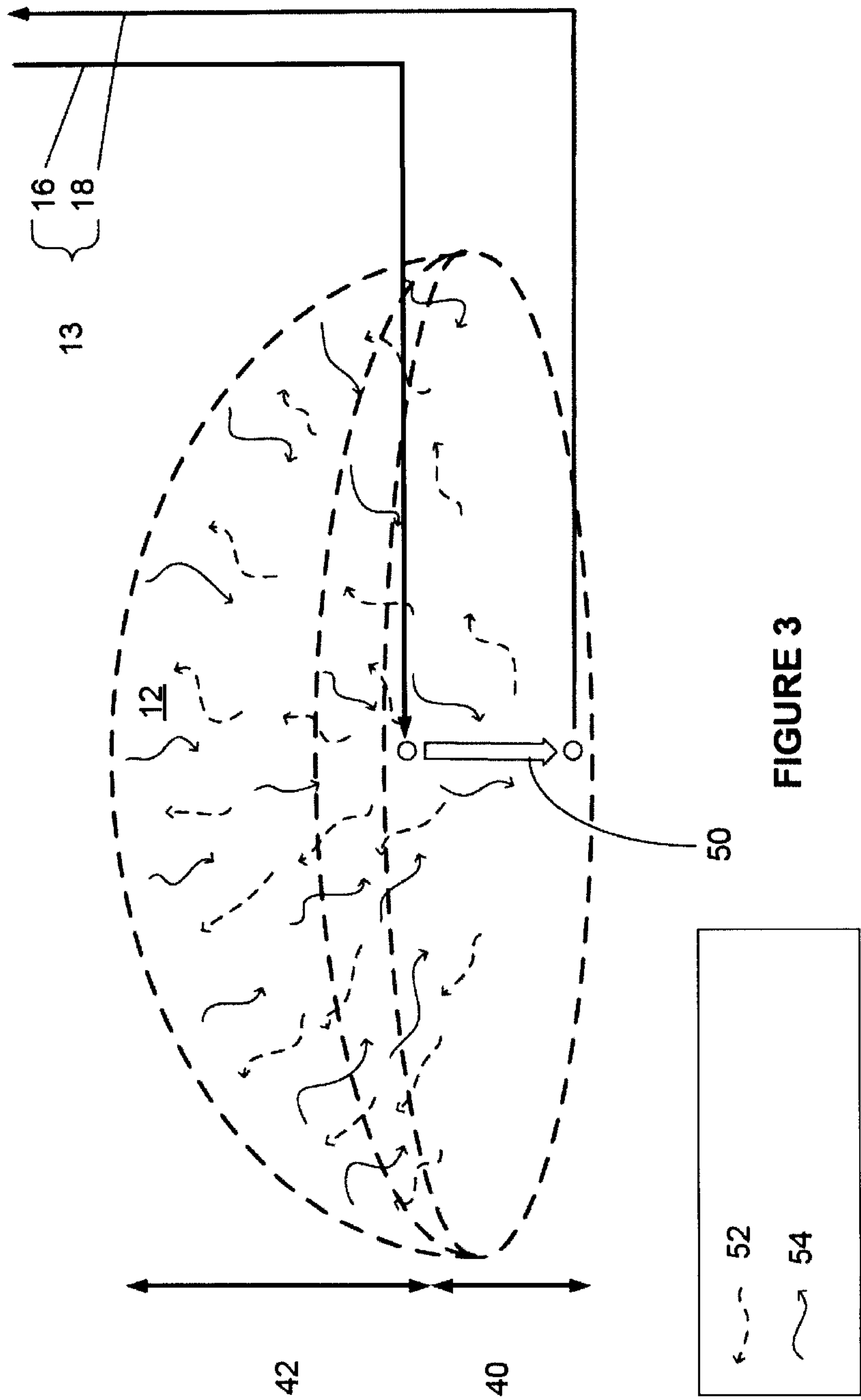
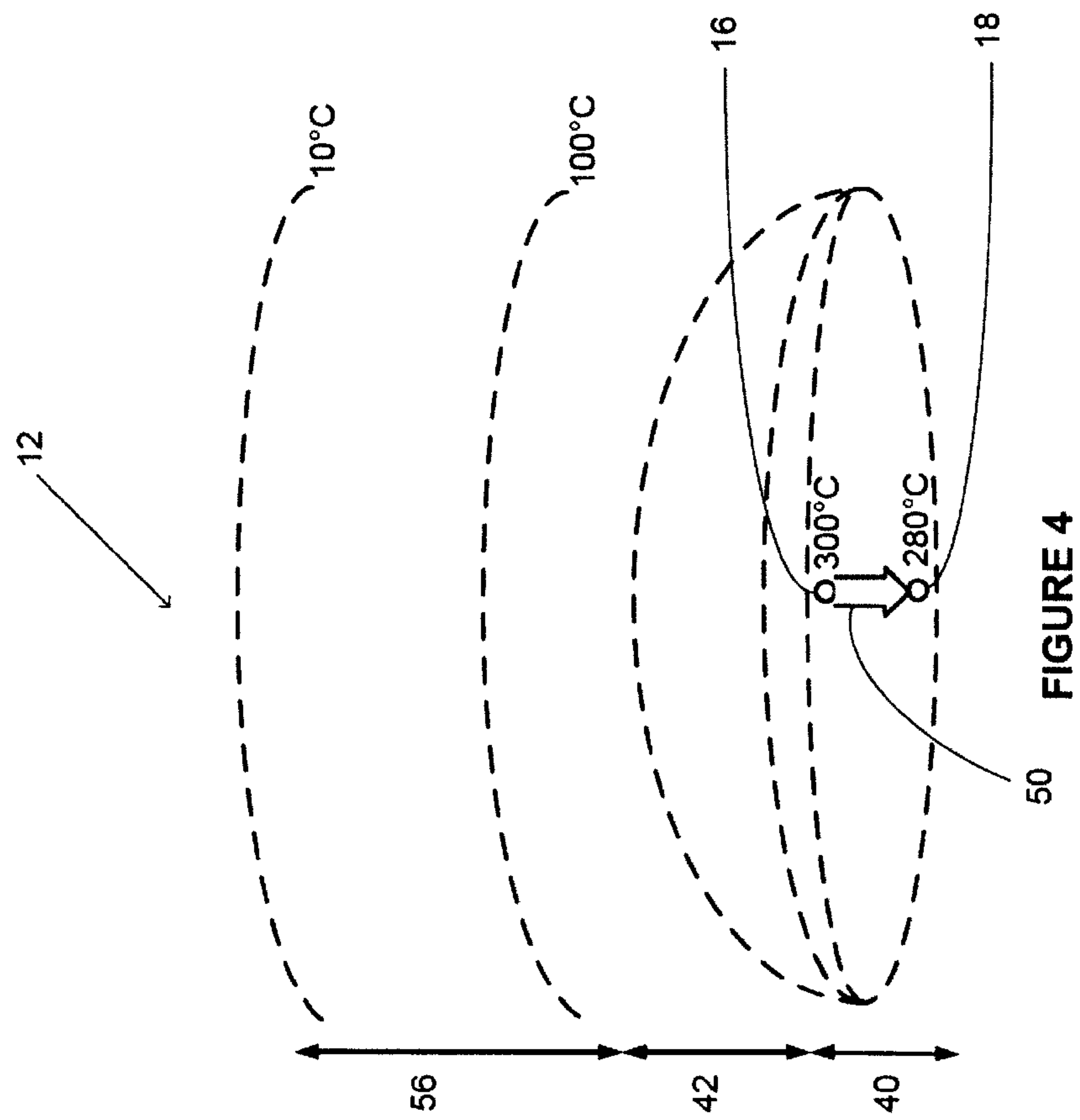


FIGURE 3



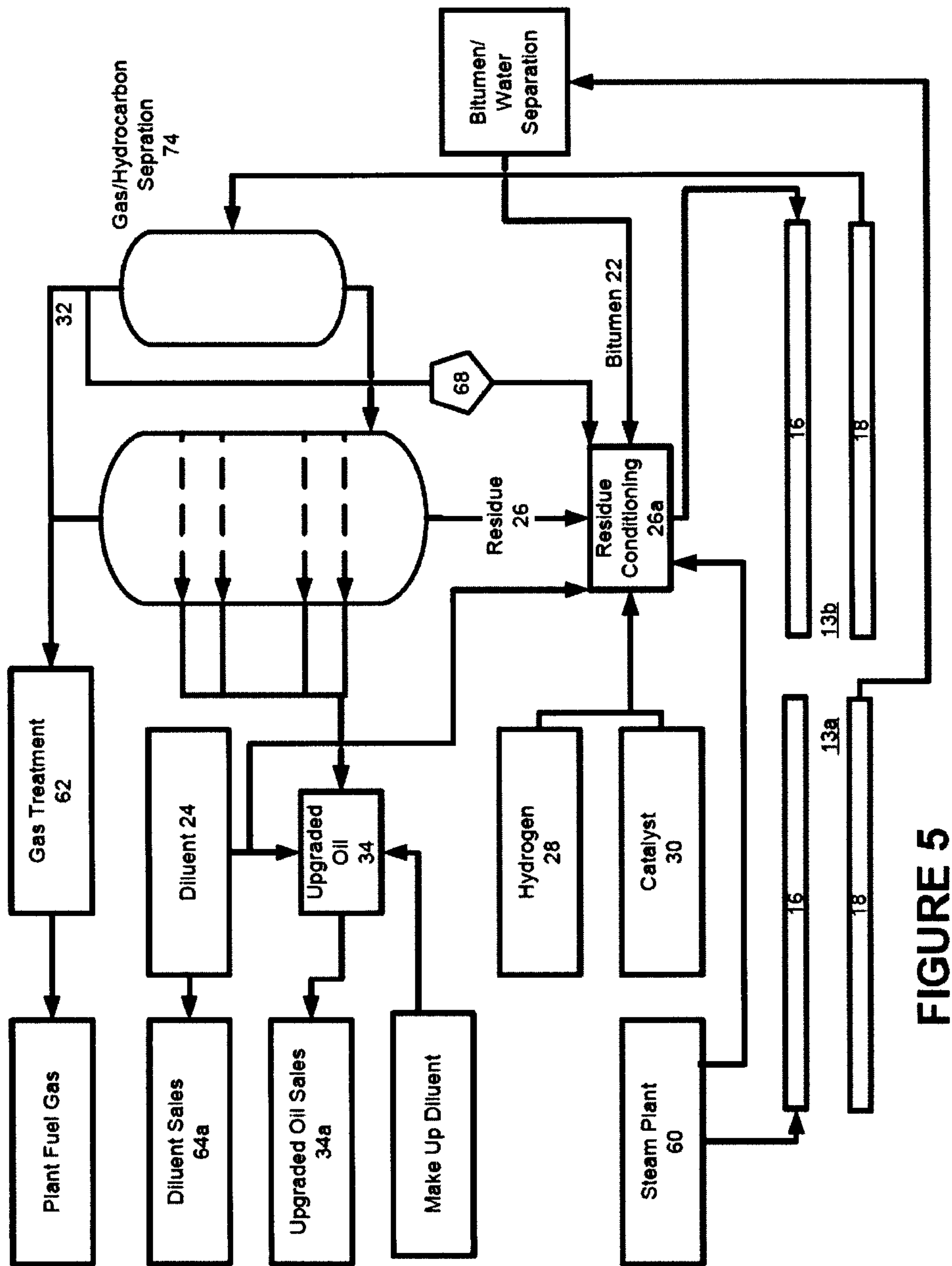
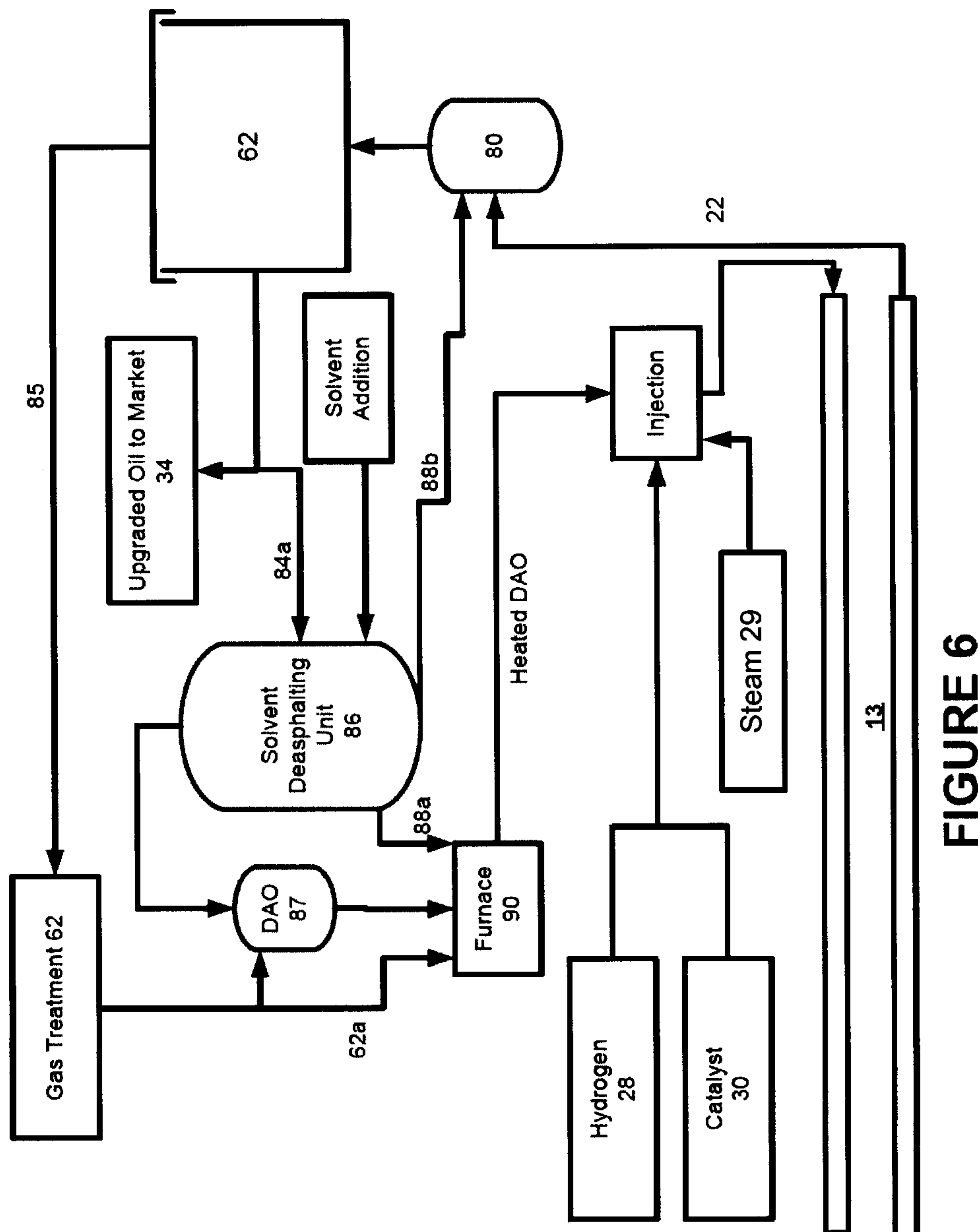


FIGURE 5



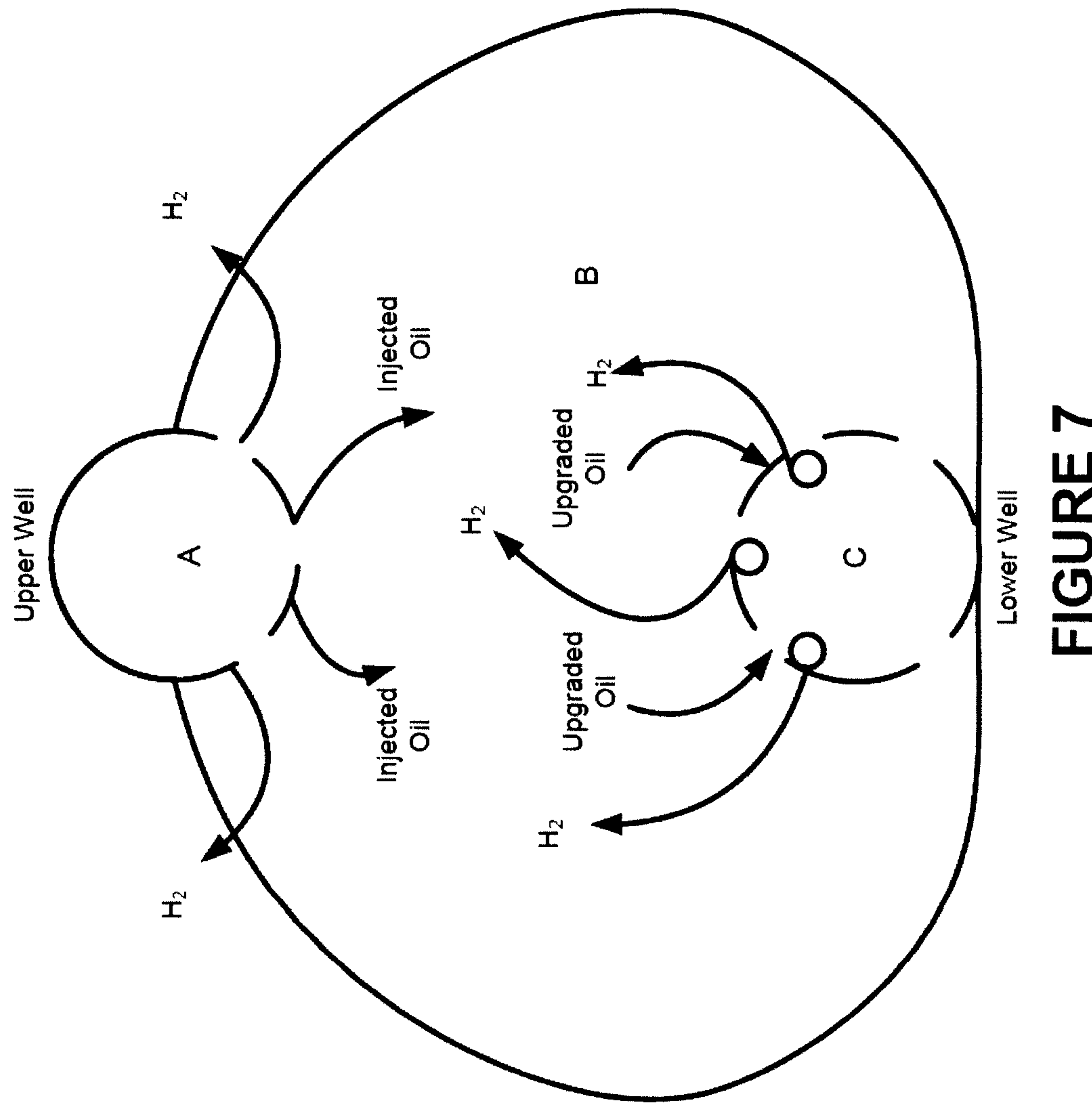


FIGURE 7

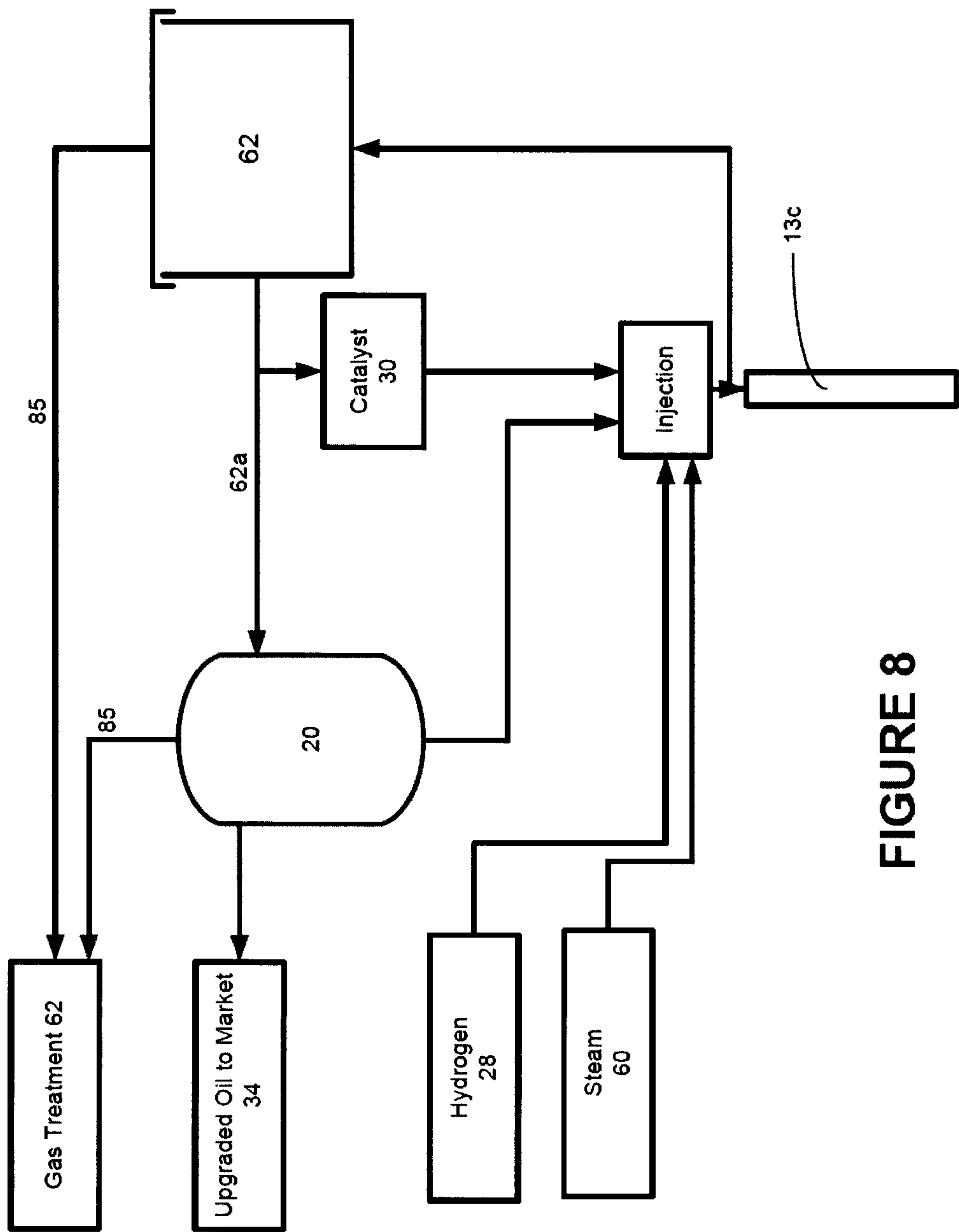


FIGURE 8

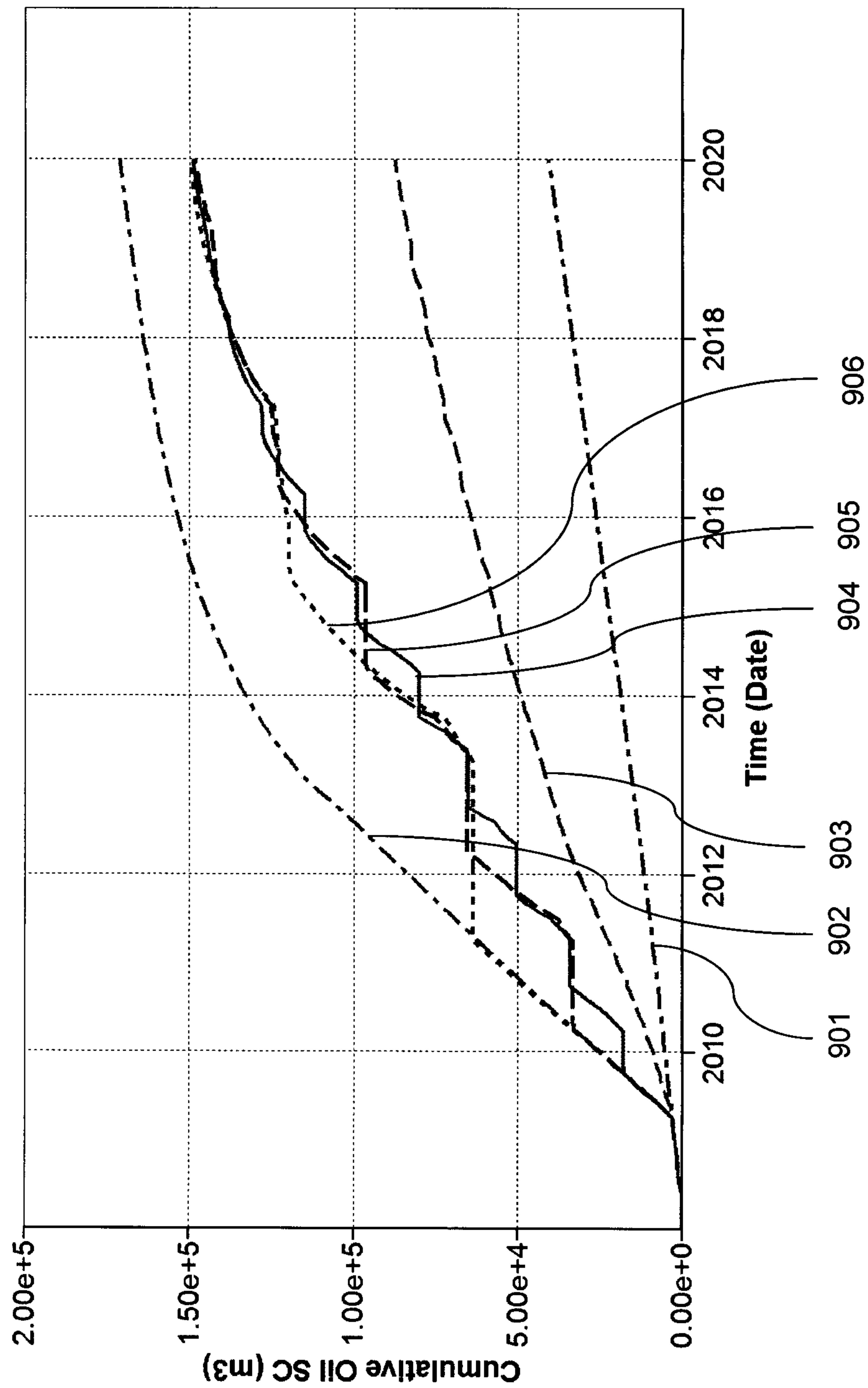


Figure 9

Figure 10b (Case 2)

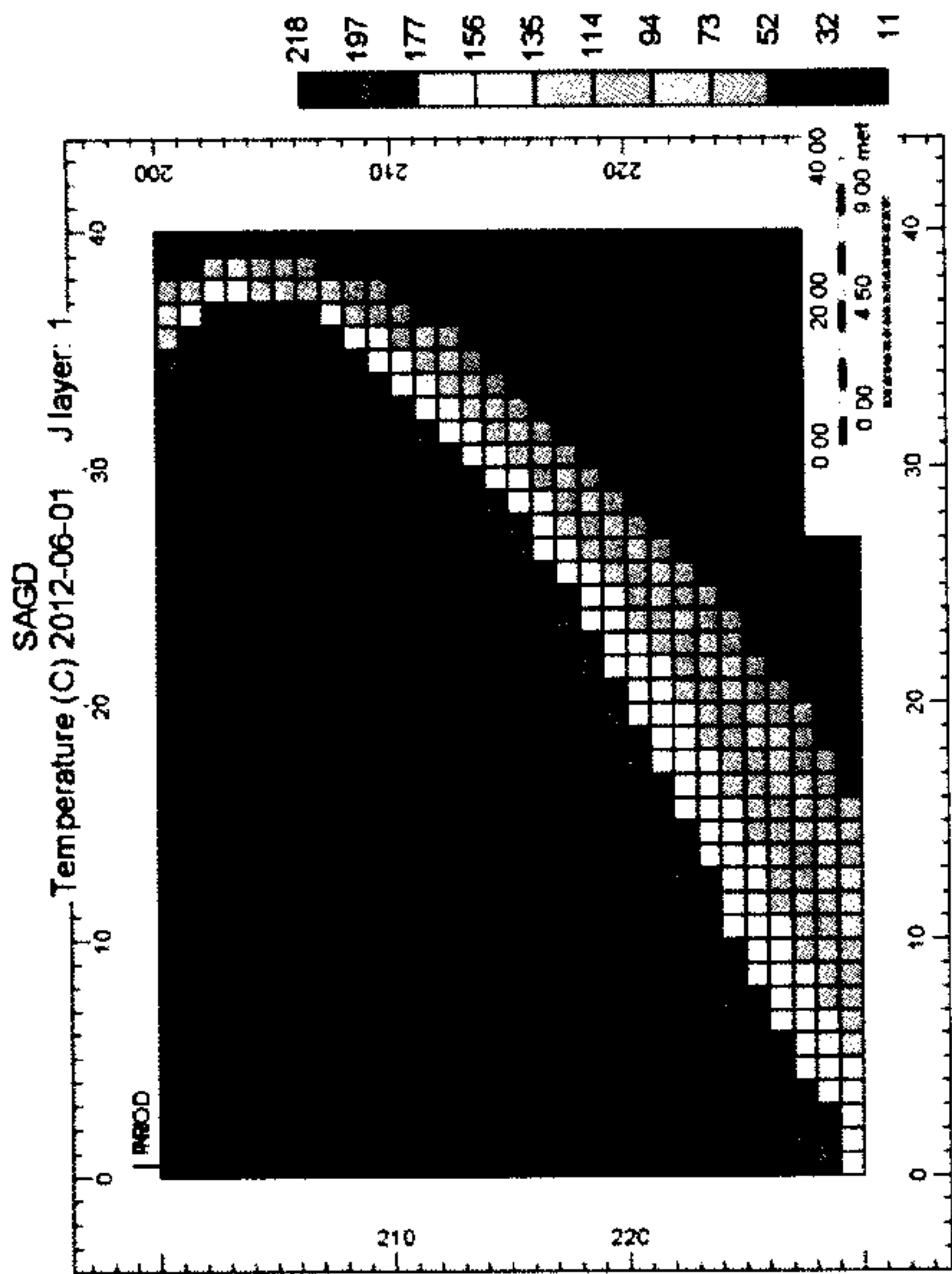


Figure 10d (Case 4)

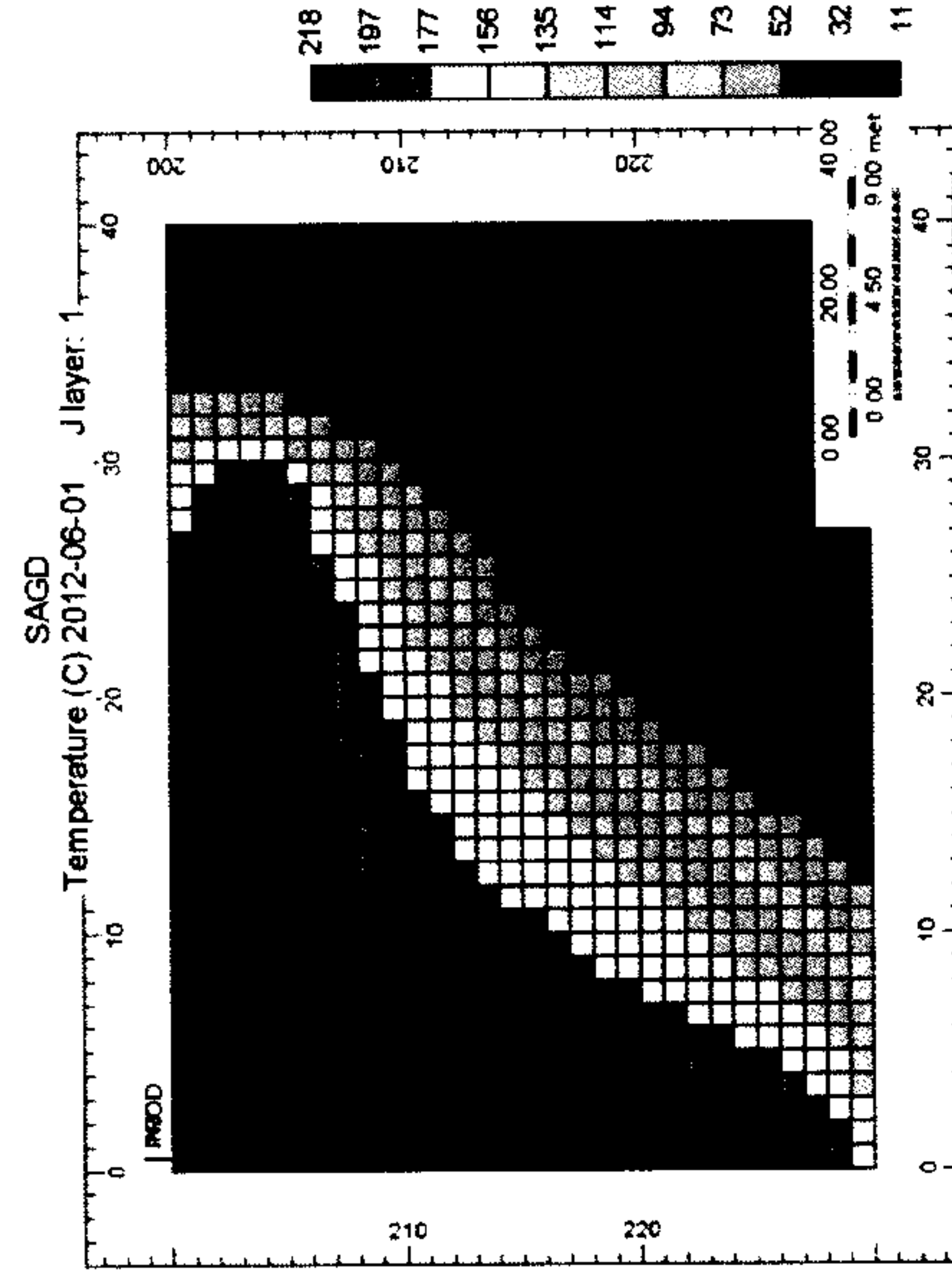


Figure 10a (Case 1)

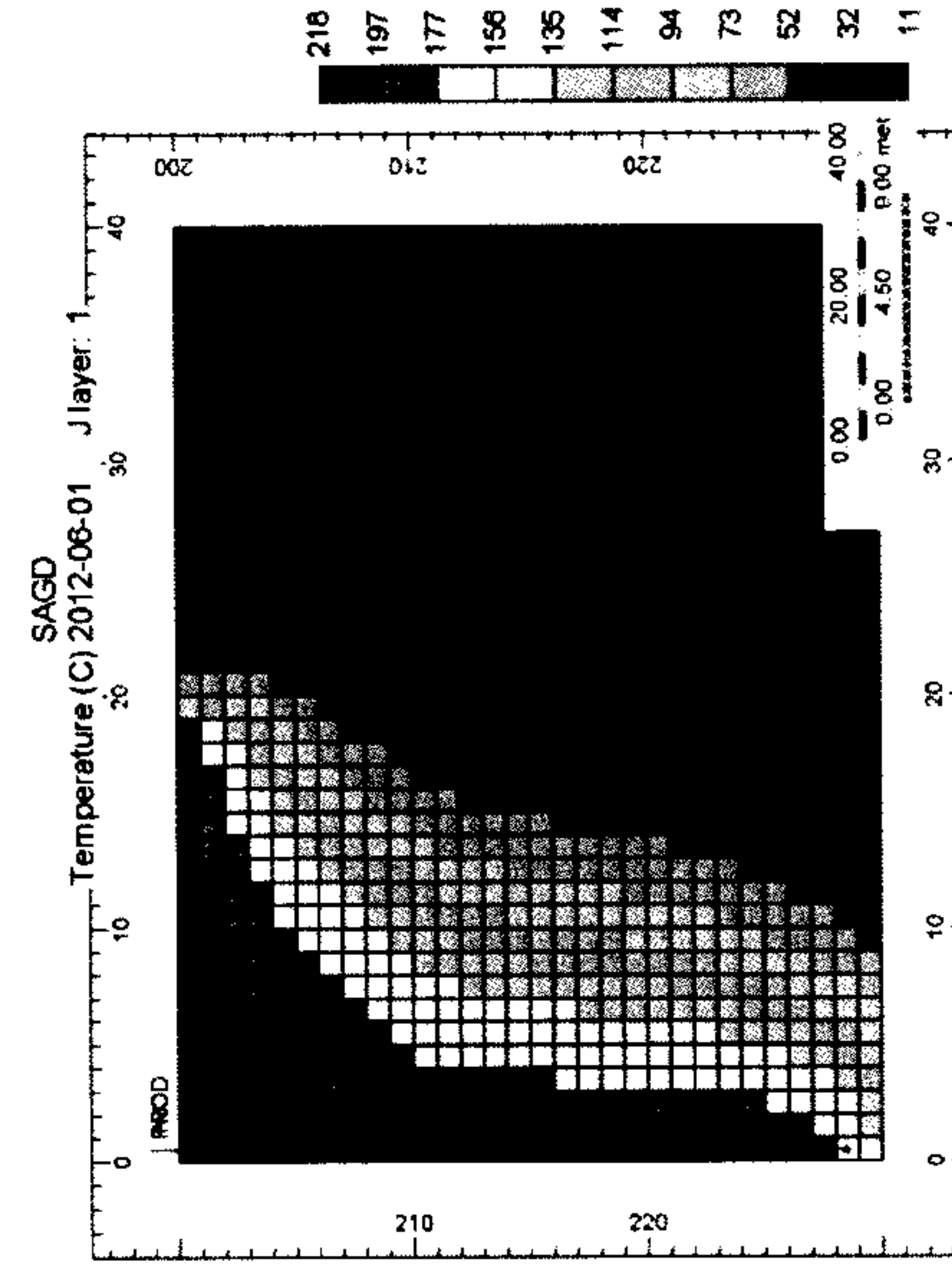
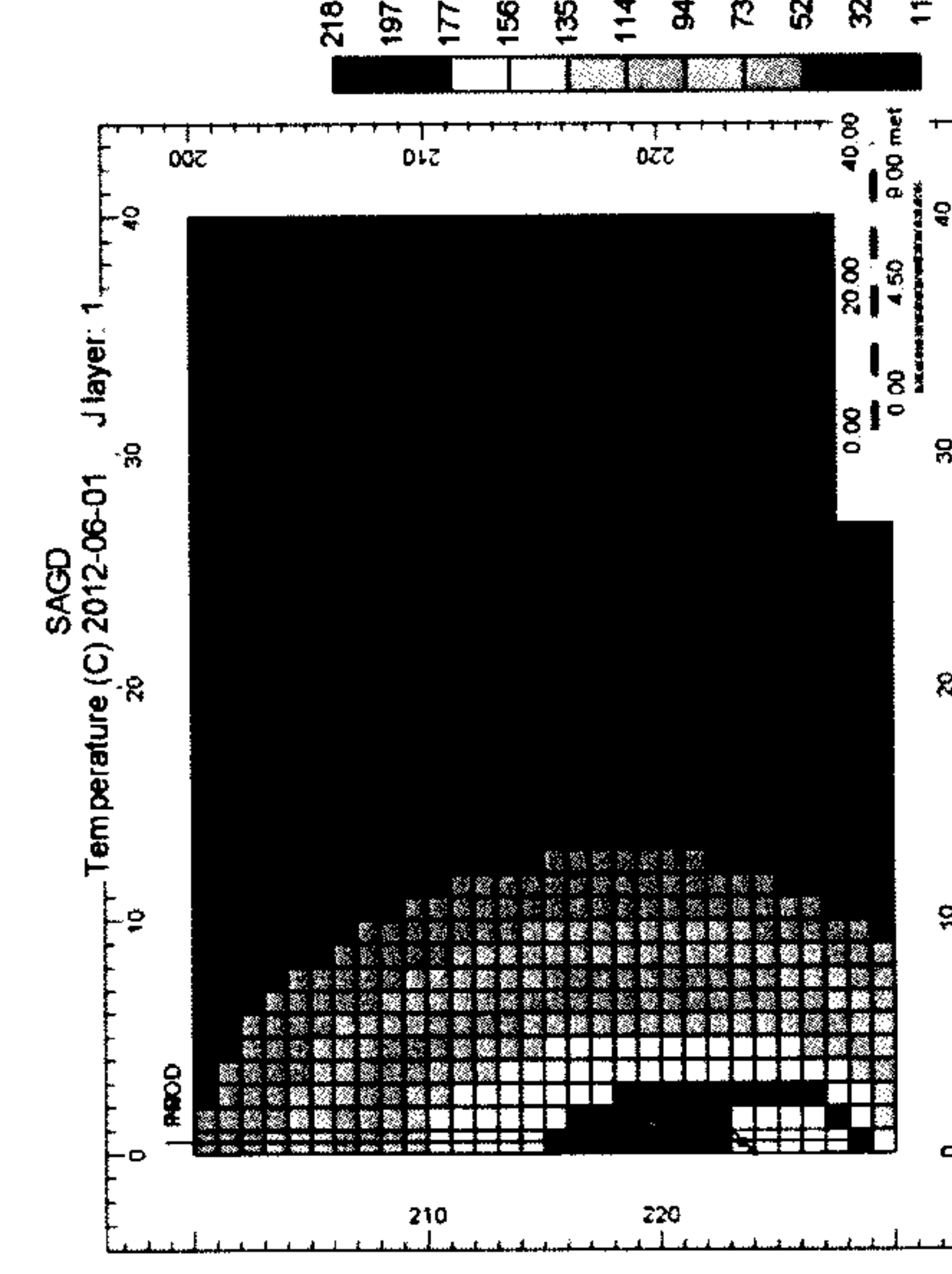


Figure 10c (Case 3)



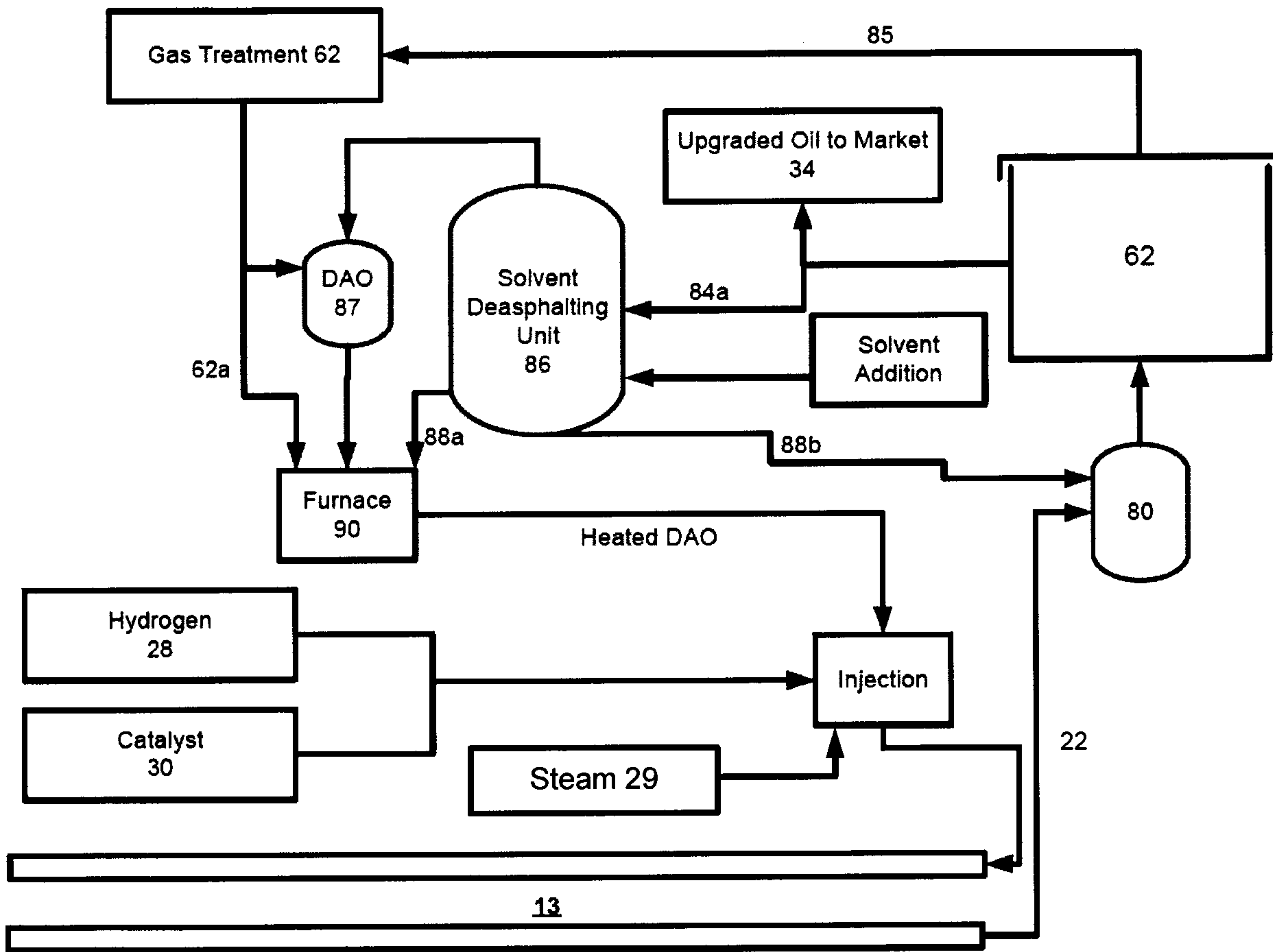


FIGURE 6