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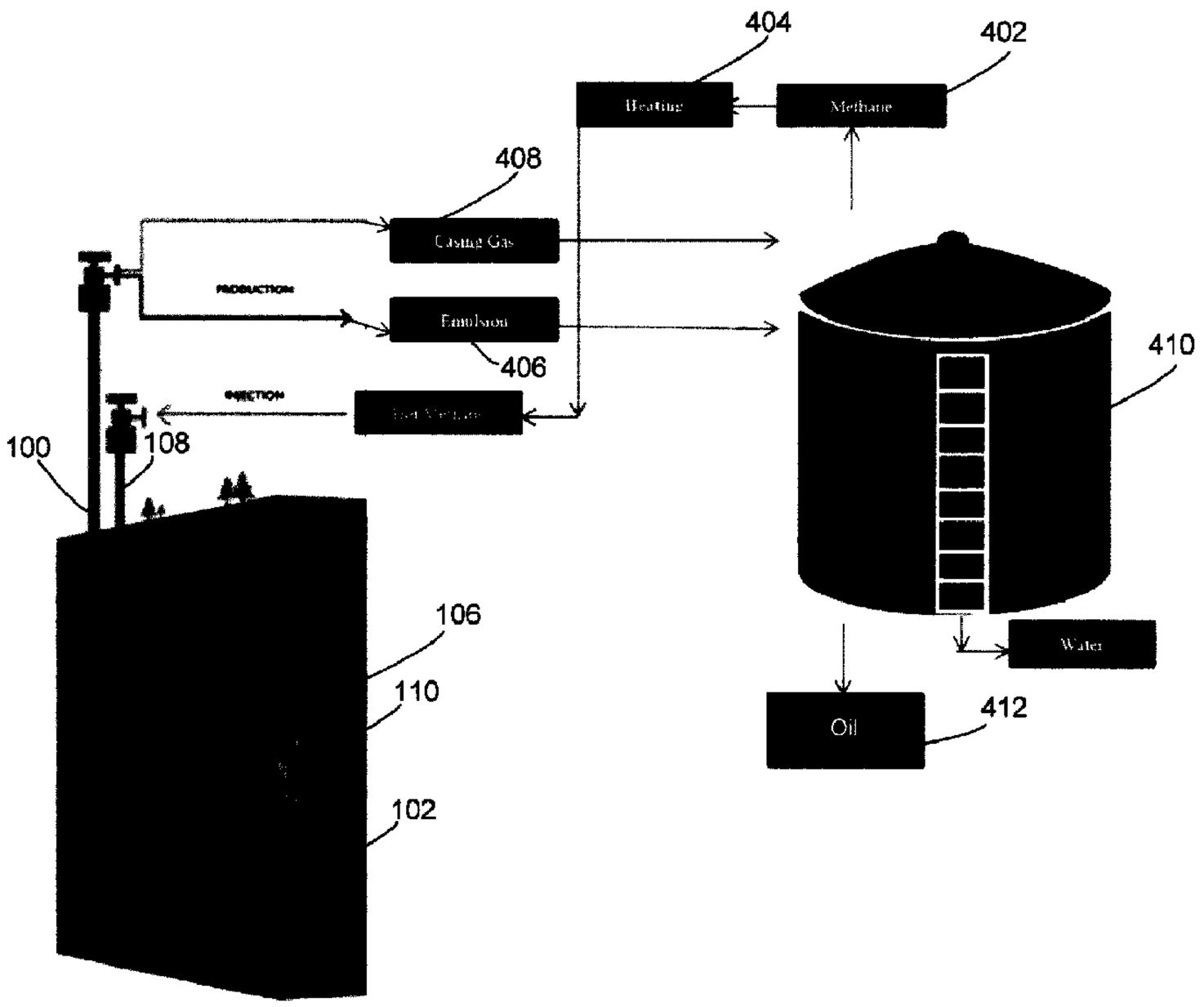
(71) Demandeur/Applicant:
CENOVUS ENERGY INC., CA

(72) Inventeur/Inventor:
BEN-ZVI, AMOS, CA

(74) Agent: BORDEN LADNER GERVAIS LLP

(54) Titre : PROCEDE DE RECUPERATION D`HYDROCARBURES A PARTIR D`UNE FORMATION PETROLIFERE
(54) Title: PROCESS FOR HYDROCARBON RECOVERY FROM A HYDROCARBON-BEARING FORMATION



(57) Abrégé/Abstract:
A process for recovering hydrocarbons from a subterranean hydrocarbon-bearing formation includes establishing fluid communication within the hydrocarbon- bearing formation, between an injection well and a production well, injecting methane

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(57) Abrégé(suite)/Abstract(continued):
through the injection well, into the hydrocarbon-bearing formation, the methane heated to a temperature sufficient for one or both of pyrolysis of the methane or reaction of hydrocarbons in the hydrocarbon-bearing formation, and producing fluids including emulsion from the hydrocarbon-bearing formation to a surface through the production well, the emulsion including at least a portion of the one or both of the hydrocarbons and pyrolized methane.

Abstract

A process for recovering hydrocarbons from a subterranean hydrocarbon-bearing formation includes establishing fluid communication within the hydrocarbon-bearing formation, between an injection well and a production well, injecting methane through the injection well, into the hydrocarbon-bearing formation, the methane heated to a temperature sufficient for one or both of pyrolysis of the methane or reaction of hydrocarbons in the hydrocarbon-bearing formation, and producing fluids including emulsion from the hydrocarbon-bearing formation to a surface through the production well, the emulsion including at least a portion of the one or both of the hydrocarbons and pyrolized methane.

PROCESS FOR HYDROCARBON RECOVERY FROM A HYDROCARBON-BEARING FORMATION

Technical Field

[0001] The present disclosure relates to the production of hydrocarbons from a subterranean formation bearing heavy oil or bitumen.

Background

[0002] Extensive deposits of viscous hydrocarbons exist around the world. Reservoirs of such deposits may be referred to as reservoirs of heavy hydrocarbon, heavy oil, extra-heavy oil, bitumen, or oil sands, and include large subterranean deposits in Alberta, Canada that are not susceptible to standard oil well production technologies. The hydrocarbons in such deposits are typically highly viscous and do not flow at commercially relevant rates at the temperatures and pressures present in the reservoir. For such reservoirs, various recovery techniques may be utilized to mobilize the hydrocarbons and produce the mobilized hydrocarbons from wells drilled in the reservoirs. For example, thermal techniques may be used to heat the reservoir to mobilize the hydrocarbons and produce the heated, mobilized hydrocarbons from wells.

[0003] Hydrocarbon substances of high viscosity are generally categorized as "heavy oil" or as "bitumen". Although these terms are in common use, references to heavy oil and bitumen represent categories of convenience, and there is a continuum of properties between heavy oil and bitumen. Accordingly, references to such types of oil herein include the continuum of such substances, and do not imply the existence of some fixed and universally recognized boundary between the substances.

[0004] One thermal method of recovering viscous hydrocarbons from a subterranean hydrocarbon-bearing formation using spaced horizontal wells is

known as steam-assisted gravity drainage (SAGD). Various embodiments of the SAGD process are described in Canadian Patent No. 1,304,287 and corresponding U.S. Patent No. 4,344,485. In the SAGD process, steam is injected through an upper, horizontal, injection well into a viscous hydrocarbon reservoir while hydrocarbons are produced from a lower, parallel, horizontal, production well that is vertically spaced from and near the injection well. The injection and production wells are located close to the base of the hydrocarbon deposit to collect the hydrocarbons that flow toward the production well.

[0005] Such a process utilizes significant volumes of water for the production of steam, and may require additional equipment to handle the steam or gasses produced.

[0006] A solvent may be utilized to aid a steam-assisted recovery process, in a so-called solvent-aided process (SAP). To further reduce steam use, solvent may be injected without steam in a solvent-only (solvent-based) recovery process. Hydrocarbon solvent is generally utilized to improve mobility in the hydrocarbon reservoir, potentially improving production and/or reducing steam and/or heating requirements. However, the use of solvent for example, propane, butane, or condensate, can add significant expense due to solvent costs. Such solvents are in demand for hydrocarbon recovery, reducing availability and driving up cost. In addition, solvents, if injected, may be recovered and/or recycled, requiring additional surface processing apparatus. Challenges remain in providing solvent- recovery processes for efficient and effective commercial application. Solvent aided recovery processes are processes involving solvent and steam and light hydrocarbons, referred to as solvent aided process (SAP). The volume of light hydrocarbons injected may be relatively small compared to the volume of steam injected, for example, about 20 weight % solvent and not more than 50 weight % solvent. Solvent-driven processes, generally involve less light hydrocarbons than steam. For example, the volume of light hydrocarbons injected may be about 50 weight % and up to about 100 weight %. In solvent-

based recovery processes, the solvent is generally injected without steam during a production stage of the recovery process.

[0007] Improvements in hydrocarbon production from viscous, subterranean hydrocarbon deposits are desirable.

Summary

[0008] According to an aspect of an embodiment, there is provided a process for recovering hydrocarbons from a subterranean hydrocarbon-bearing formation. The process includes establishing fluid communication within the hydrocarbon-bearing formation, between an injection well and a production well, injecting methane through the injection well, into the hydrocarbon-bearing formation, the methane heated to a temperature sufficient for one or both pyrolysis of the methane or reaction with hydrocarbons present in the hydrocarbon-bearing formation, and producing fluids including emulsion from the hydrocarbon-bearing formation to a surface through the production well, the emulsion including at least a portion of the hydrocarbons and pyrolized methane.

Brief Description of the Drawings

[0009] Embodiments of the present invention will be described, by way of example, with reference to the drawings and to the following description, in which:

[0010] FIG. 1 is a schematic sectional view of a reservoir and shows the relative location of an injection well and a production well;

[0011] FIG. 2 is a sectional side view of a well pair including an injection well and a production well;

[0012] FIG. 3 is a flowchart showing a process for producing fluids from a subterranean hydrocarbon-bearing reservoir according to an embodiment;

[0013] FIG. 4 is a flow diagram illustrating the process for producing fluids from a subterranean hydrocarbon-bearing reservoir in accordance with an aspect of an embodiment;

[0014] FIG. 5 is a graph showing variation of reaction rate of thermal decomposition of methane with temperature and pressure;

[0015] FIG. 6 is a graph illustrating the effect of methane pressure on percentage of conversion of >540°C fraction, and viscosity of the product of the reaction of methane with heavy oil;

[0016] FIG. 7 is a graph illustrating the effect of water content on conversion of >540°C fraction, viscosity, and sulfur removal during upgrading of heavy oil with methane; and

[0017] FIG. 8 is a graph showing oil production rate and cumulative steam to oil ratio (equivalent) for a simulated production in accordance with an example of the process of FIG. 3.

Detailed Description

[0018] For simplicity and clarity of illustration, reference numerals may be repeated among the figures to indicate corresponding or analogous elements. Numerous details are set forth to provide an understanding of the examples described herein. The examples may be practiced without these details. In other instances, well-known methods, procedures, and components are not described in detail to avoid obscuring the examples described. The description is not to be considered as limited to the scope of the examples described herein.

[0019] The disclosure generally relates to a process for recovering hydrocarbons from a subterranean hydrocarbon-bearing formation. The process includes establishing fluid communication within the hydrocarbon-bearing formation, between an injection well and a production well, injecting methane through the injection well, into the hydrocarbon-bearing formation, the methane heated to a temperature sufficient for one or both of pyrolysis of the methane or

reaction of hydrocarbons in the hydrocarbon-bearing formation, and producing fluids including emulsion from the hydrocarbon-bearing formation to a surface through the production well, the emulsion including at least a portion of the one or both of the hydrocarbons or pyrolized methane.

[0020] Reference is made herein to an injection well and a production well. The injection well and the production well may be physically separate wells. Alternatively, the production well and the injection well may be housed, at least partially, in a single physical wellbore. The production well and the injection well may be functionally independent components that are hydraulically isolated from each other, and housed within a single physical wellbore.

[0021] As referred to above, a steam-assisted gravity drainage (SAGD) process generally utilizes a well pair, including a hydrocarbon production well and a steam injection well. One example of a well pair is illustrated in FIG. 1 and an example of a hydrocarbon production well 100 and injection well 108 is illustrated in FIG. 2. The hydrocarbon production well 100 includes a generally horizontal segment 102 that extends near the base or bottom 104 of the hydrocarbon reservoir 106. The injection well 108 also includes a generally horizontal segment 110 that is disposed generally parallel to and is spaced generally vertically above the horizontal segment 102 of the hydrocarbon production well 100.

[0022] A similar well configuration may be utilized in the present process. Other well configurations may also be utilized to successfully implement the present process, however. As indicated above, the injection well and the production well may alternatively be housed, at least partially, in a single physical wellbore. The production well and the injection well may be functionally independent components that are hydraulically isolated from each other, and housed within a single physical wellbore. The injection and the production wells may also be vertical wells. In addition, there may be more injection wells than production wells or more production wells than injection wells. Further still, use

of the injection wells and production wells may be discontinuous such that injection wells and production wells are active at different times.

[0023] A process for producing fluids from a subterranean hydrocarbon-bearing reservoir according to an embodiment is shown in FIG. 3 and a flow diagram illustrating the process for producing fluids in accordance with an example of FIG. 3 is shown in FIG. 4. The process may include additional or fewer elements than shown and described and, the elements of the process may be carried out simultaneously or in a different order than that shown in FIG. 3. The process may be carried out in a formation such as the reservoir 106 described with reference to FIG. 1 or FIG. 2.

[0024] A start-up procedure is first carried out to establish fluid communication between the injection well 108 and the adjacent production well 100 at 302. Any suitable start-up procedure may be utilized, such as for example hot fluid (e.g., steam or hot water) wellbore circulation, the use of selected solvents such as xylene (as, for example, described in CA 2,698,898 to Pugh, et al.), the application of geomechanical techniques such as dilation (as, for example, described in CA 2,757,125 to Abbate, et al.), the use of surfactants (as, for example, described in CA 2,886,934 to Zeidani), or the use of one or more microorganisms to increase overall fluid mobility in a near-wellbore region in an oil sands reservoir (as, for example, in CA 2,831,928 to Bracho Dominguez, et al.) A start-up procedure may utilize steam, solvent, heater(s), or a combination thereof. More than one start-up procedure may be utilized to establish fluid communication.

[0025] In this example, fluid is injected through the injection well 108 at 302. The fluid may include steam, and may also include a solvent or solvents and, optionally, a non-condensable gas (NCG), such as methane (or natural gas), and steam injected into the injection well 108 and into the reservoir 106. The fluid may be injected into the injection well 108 continuously until fluid communication is established between the injection well 108 and the production well 100. NCGs include, but are not limited to air, nitrogen, carbon dioxide,

methane, natural gas, other light hydrocarbons, or a combination thereof. The start-up procedure may also include electrically heating utilizing, for example, electrical heating elements, in addition to or rather than utilizing steam.

[0026] Hydrocarbon production may be low as fluid communication is established. After fluid communication is established, the fluids move toward the production well 100 and are produced to the surface at 304 through the production well 100.

[0027] An injection fluid such as steam may optionally be injected after establishing fluid communication between the injection well 108 and the production well 100, to further heat the reservoir and facilitate mobilizing the hydrocarbons. Alternatively, or in addition, a single solvent or a mixture of solvents may be injected for a relatively short period of time as the heat in the reservoir resulting from startup is utilized to vaporize the solvent. In a particular example, propane is injected at a temperature of 100°C. This temperature may be dependent on the conditions of the particular reservoir and properties of the solvent mixture. The solvent vapor contacts the hydrocarbons, which may be bitumen or heavy oil, in the reservoir 106 and condenses. The solvent serves to dissolve an oleic phase, reducing the viscosity and mobilizing the oleic phase. A catalyst may optionally be utilized. Suitable catalysts may include, for example, a metal or zeolite.

[0028] Heated methane is injected into the formation at 306. The methane 402 may be heated 404 prior to injecting, as illustrated in FIG. 4, and then injected through the injection well 108 and into the hydrocarbon-bearing formation. Alternatively or in addition, the methane may be heated during injection into the injection well. For example, the methane may be heated within the injection well 108 during the injection of methane.

[0029] The methane is heated to a temperature sufficient for one or both of thermal decomposition of the methane or reaction with the hydrocarbons in the hydrocarbon-bearing formation. For example, the methane may be heated to a temperature of about 350°C to a temperature of about 800°C. The methane may

be heated to a temperature of about 700°C or greater. The methane may initially be injected at a temperature of less than 540°C and may be ramped up to a temperature in the range of about 540°C to a temperature of about 800°C. Residence time in the formation increases with decreasing temperature to provide sufficient reaction time. Similarly, residence time may decrease with increasing temperature of the methane.

[0030] Methane injection may commence after recovery of about 10% to about 20% of the hydrocarbons from the reservoir. In another example, methane injection may commence, for example, after about 50% to about 60% recovery of hydrocarbons, prior to cool down or prior to blowdown.

[0031] The methane may be injected at an injection pressure of 2000 kPa or greater. The reservoir pressure may be, for example, in the range of from about 2000 kPa to about 5000 kPa in the hydrocarbon-bearing formation. Methane may be injected at a pressure sufficient to achieve a pressure of up to about 9000 kPa in the hydrocarbon-bearing formation, for example, in applications in which high pressure cyclic steam stimulation is employed. The injection may be generally continuous at a generally constant pressure. Alternatively, the injection of methane may continue until a target pressure in the reservoir is achieved and then the injection may be discontinued or slowed for a period of time, thus injecting discontinuously or at varying pressure. The injection of heated methane may increase with time to increase the hydrocarbon production rate.

[0032] Thermal decomposition of the methane is described, for example, by Chen, C-J., et al. in "The Thermal Decomposition of Methane. I. Kinetics of the Primary Decomposition to C_2H6 + H_2; Rate Constant for the Homogeneous Unimolecular Dissociation of Methane and its Pressure Dependence", Can J Chem 53, 3580 (1975), by the following reactions:

$$[1] \quad CH_4 \rightarrow CH_3 + H$$

$$[2] \quad H + CH_4 \rightarrow CH_3 + H_2$$

$$[3] \quad 2CH_3 \rightarrow C_2H_6$$

$$[4] \quad CH_3 + C_2H_6 \rightarrow CH_4 + C_2H_5$$

$$[5] \quad C_2H_5 \rightarrow C_2H_4 + H$$

[0033] Equations [1] to [3] were identified as early stage reactions and equations [4] and [5] were identified as late stage reactions. Variation in the reaction rate for the reaction in equation 1 is temperature and pressure dependent as shown in the graph of FIG. 5, which illustrates variation of reaction rate of thermal decomposition of methane with temperature and pressure.

[0034] The methane dissociation produces free radicals that have an effect on bitumen upgrading. It was found by Ovalles, C., et al. (1995) Fuel Vol 74, 1162, that, after only 4 hours, Hemaca bitumen, for example, incubated with hot methane showed a significant decrease in viscosity, and percent conversion of >540°C fraction. The methane dissociation produces free radicals that have an effect on bitumen upgrading. Using the >540°C fraction as a reference case (which resulted in certain viscosity reduction and residue conversion), it was found by Ovalles, C., et al. (1995) Fuel Vol 74, 1162, that, the reaction of extra-heavy crude oil at 11 MPa of methane and 380°C for 4 hours led to a two orders of magnitude decrease in the viscosity of the upgraded product, 60% conversion of the >540°C fraction case.

[0035] FIG. 6 illustrates the effect of methane pressure on percentage of conversion of >540°C fraction case and viscosity of the product of the reaction of methane with extra-heavy crude oil. FIG. 7 illustrates the effect of water content of conversion of >540°C fraction case, viscosity, and sulfur removal during upgrading of extra-heavy crude oil with methane.

[0036] The methyl free radicals directly affect the molecular structure of the bitumen, in particular, the ring structures of asphaltene within the bitumen. Ovalles, C., et al. (1995) Fuel Vol 74, 1162 showed that the methane

incorporates into the thermally upgraded crude oils and the presence of water has a synergistic effect on the process.

[0037] The temperature of the methane may be controlled to control the reaction of the injected methane. For example, the temperature may be reduced to slow the reaction or increased to speed up the reaction.

[0038] Optionally, other gasses may be injected, such as one or more of amines, alcohols, steam, hydrogen, or other molecules that may react with pyrolysis products of methane. Such reactions may form solvents or surfactants in-situ.

[0039] The fluid production referred to above at 304 continues as fluids are produced to the surface through the production well 100. The fluids produced include an emulsion 406 and casing gas 408. The emulsion includes the products of the reaction of the relatively heavier hydrocarbons in the hydrocarbon-bearing formation with the methyl free radicals. The fluids may be produced utilizing artificial lift, for example, utilizing a submersible pump. Methane is produced from both an emulsion line and a casing gas line. Alternatively, the fluids may be produced utilizing gas lift, in which case the emulsion 406 and casing gas 408 may be produced in the same production stream.

[0040] The produced fluids are treated at 308 at the well pad or at a central surface facility 410 to separate the hydrocarbons 412. The produced fluids include products of the reaction of the relatively heavier hydrocarbons in the hydrocarbon-bearing formation with the methyl free radicals, along with native hydrocarbons from the formation, and dissolved gasses. The light ends, or lighter hydrocarbons such as propane and/or butane, from the fluids that are produced may, optionally, be recovered or partially recovered. These light ends may optionally be utilized as solvents for oil production.

[0041] Optionally, a catalyst may be injected through the injection well. A catalyst may be injected at any suitable time. For example, the catalyst may be injected during establishing fluid communication at 302. Alternatively or in

addition, catalyst may be injected along with the optional injection of steam or solvent or both. Catalyst may also be optionally injected along with the heated methane at 306.

[0042] Methane recovered from the treatment at 308 may be separated out, recycled, and reused for injection at 306, thus injecting cyclically.

[0043] The injection and production wells may be operated to control the production of fluids at 304 and the injection of methane 306 to maintain a temperature difference between the injection well and the production well of, for example, about 10°C or more, or, for example about 50°C to about 150°C, allowing a layer of mobilized fluid to accumulate above the horizontal section of the production well. The injection and production wells may also be operated to control the production of fluids at 304 and the injection of methane at 306 to maintain a temperature difference between the injection well and the production well of, for example, about 150°C or greater to increase residence time for the reaction of the relatively heavier hydrocarbons in the hydrocarbon-bearing formation with the methyl free radicals to occur.

[0044] After producing fluids and injecting the heated methane, methane at a lower temperature may be injected during cool down at 310. Surface or subsurface heating of the methane may still be carried out. The methane may be injected, however, at a temperature of less than 540°C. The methane may be heated in the reservoir as a result of the heat built up in the reservoir. Production of fluids and thus recovery of hydrocarbons continues during cool-down. Hydrocarbon production rates may be reduced during the cool-down.

[0045] After cool-down of the reservoir at 310, the hydrocarbon recovery operation may enter an ending or winding down, blowdown phase at 312. The blowdown phase may be performed in which methane is injected without heating while production of fluids and recovery of hydrocarbons continues, thus allowing the temperature in the reservoir to decrease. The methane may be injected to generally maintain pressure in the reservoir during production. As the volume of hydrocarbons in the reservoir declines, the reservoir eventually reaches at point

at which production is not economically sufficient to continue production or injection. When the reservoir is at or near this economic limit, pressure within the reservoir and the temperature may be allowed to decline. Production may be discontinued and methane may still be injected to maintain pressure, for example, for a neighboring well.

EXAMPLES

Modelling

[0046] A reservoir simulation was performed to demonstrate the process.

[0047] Methane was used as the solvent (and reactant) with a rate constant of 1.37 x 10-5 s^{-1}.

[0048] The reservoir properties of the simulation are shown in Table 1.

Table 1: Key Simulation Parameters

Reservoir Property	
Initial Oil Saturation	80 %
Initial Water Saturation	20 %
Connate Water Saturation	20 %
Vertical Permeability	1.3 D
Horizontal Permeability	5 D
Porosity	33 %
Pay Thickness	15 m
Initial Oil Viscosity	~766,000 Cp
Initial Reservoir Temperature	12 °C
Initial Reservoir Pressure	2500 kPa
Injection Pressure	4000 kPa
Injection Temperature	~625 °C

[0049] The modelling was carried out to simulate a hydrocarbon reservoir. The general layout of wells and formation was as illustrated in FIG. 1.

Results

[0050] FIG. 8 is a graph illustrating oil production rate and cumulative steam to oil ratio (equivalent) for the simulated production. As shown in FIG. 8, excellent oil production rates of >100t/d were maintained for an initial period followed by good oil rates of >50t/d for about two years. The simulation showed that oil was produced utilizing less energy than typical for a SAGD process. In addition, the oil produced may be upgraded, to have a higher market value than bitumen.

[0051] Advantageously, hydrocarbons from the hydrocarbon-bearing formation are produced utilizing methane, which is less expensive than solvents such as propane or butane. The methane at high temperature, is utilized as a reactant rather than a solvent. In addition, the hydrocarbons are produced utilizing less energy than that for other processes. The hydrocarbons produced are also upgraded, facilitating flow of the hydrocarbons and increasing market value.

[0052] The described embodiments are to be considered in all respects only as illustrative and not restrictive. The scope of the claims should not be limited by the preferred embodiments set forth in the examples, but should be given the broadest interpretation consistent with the description as a whole. All changes that come with meaning and range of equivalency of the claims are to be embraced within their scope.

Claims

1. A process for recovering hydrocarbons from a subterranean hydrocarbon-bearing formation, the process comprising:

establishing fluid communication within the hydrocarbon-bearing formation, between an injection well and a production well;

injecting methane through the injection well, into the hydrocarbon-bearing formation, the methane heated to a temperature sufficient for one or both of pyrolysis of the methane or reaction of hydrocarbons in the hydrocarbon-bearing formation;

producing fluids including emulsion from the hydrocarbon-bearing formation to a surface through the production well, the emulsion including at least a portion of the one or both of the hydrocarbons and pyrolized methane.

2. The process according to claim 1, comprising heating the methane prior to injecting the methane into the well and into the hydrocarbon-bearing formation.

3. The process according to claim 1, comprising heating in the injection well as the methane is injected to provide the heated methane in the hydrocarbon-bearing formation.

4. The process according to claim 1, wherein the methane is heated to a temperature of at least 350°C.

5. The process according to claim 1, wherein the methane is heated to a temperature of about 540°C to about 800°C.

6. The process according to claim 1, wherein the methane is heated to a temperature of at least 400°C.

7. The process according to claim 1, wherein establishing fluid communication comprises heating the hydrocarbon-bearing formation.

8. The process according to claim 7, wherein heating the hydrocarbon-bearing formation comprises injecting steam into the hydrocarbon-bearing formation.

9. The process according to claim 7, wherein heating the hydrocarbon-bearing formation comprises electrically heating the hydrocarbon-bearing formation.

10. The process according to claim 1, comprising injecting steam prior to injecting the methane.

11. The process according to any one of claims 1 to 10, comprising injecting a solvent prior to injecting methane.

12. The process according to claim 11, wherein the solvent comprises at least one of propane, butane, pentane, and any combination of propane, butane, and pentane.

13. The process according to claim 1, wherein producing emulsion comprises producing lighter hydrocarbons formed from a reaction of relatively heavier hydrocarbons in the hydrocarbon-bearing formation.

14. The process according to claim 1, wherein a viscosity of the portion of hydrocarbons produced is reduced by reaction with the methane.

15. The process according to claim 1, comprising burning off methane from fluids produced.

16. The process according to claim 1, comprising recycling methane from the fluids produced.

17. The process according to claim 1, comprising recovering light ends from the fluids produced.

18. The process according to claim 1, wherein injecting methane comprises injecting at a pressure sufficient to achieve a pressure of at least 2000 kPa in the hydrocarbon-bearing formation.

19. The process according to claim 1, wherein injecting methane comprises injecting at a pressure sufficient to achieve a pressure of from about 2000 kPa to about 5000 kPa in the hydrocarbon-bearing formation.

20. The process according to claim 1, wherein injecting methane comprises injecting at a pressure sufficient to achieve a pressure of up to about 9000 kPa in the hydrocarbon-bearing formation.

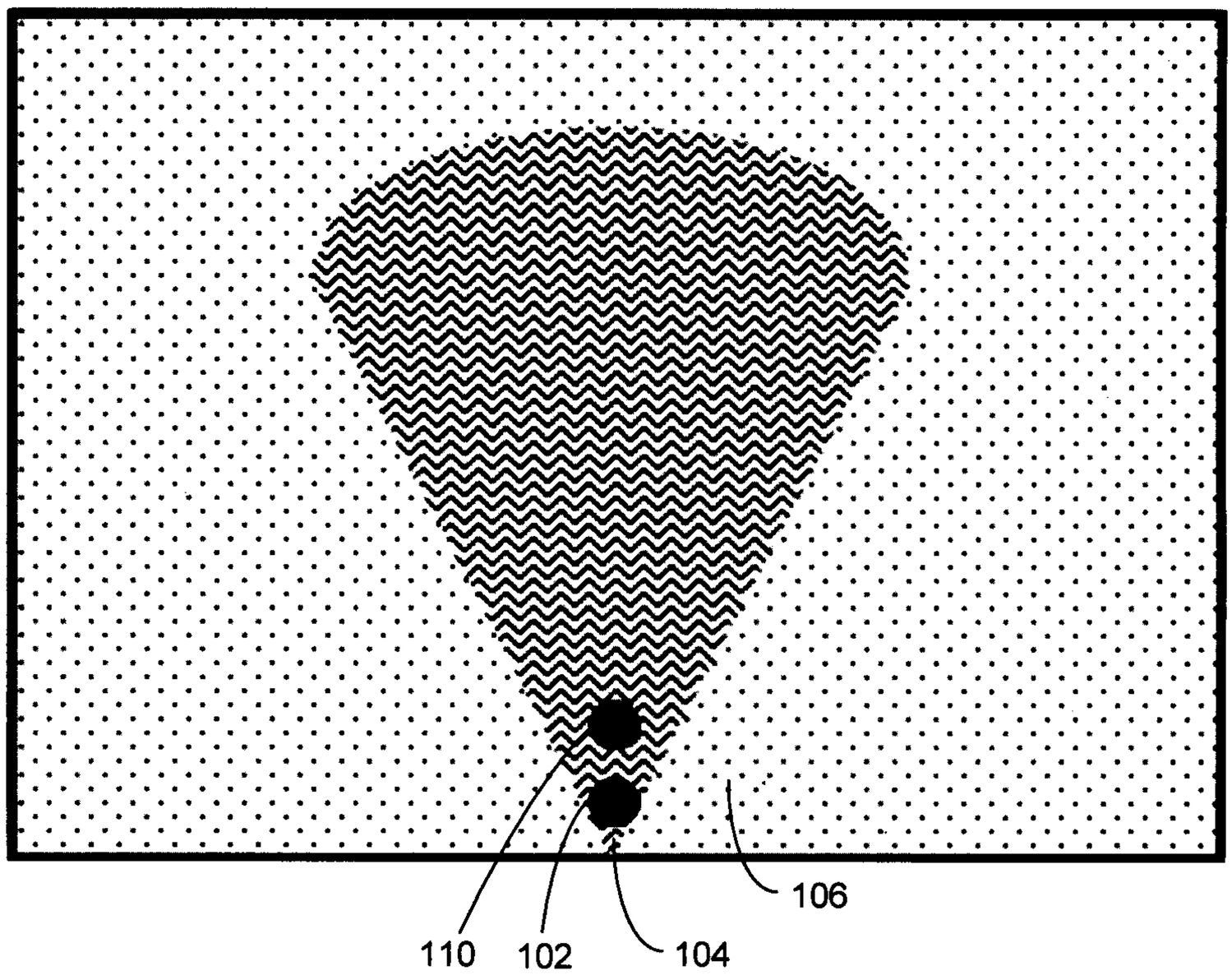


FIG. 1

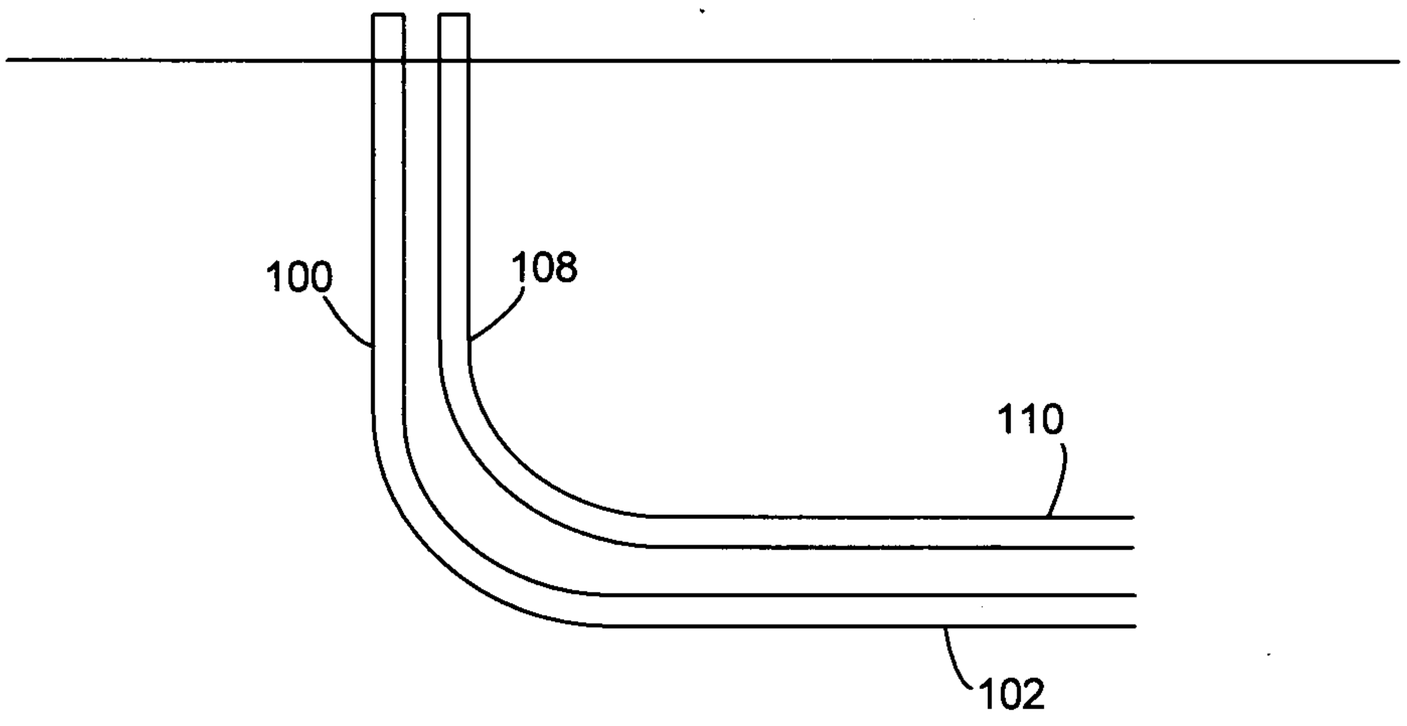


FIG. 2

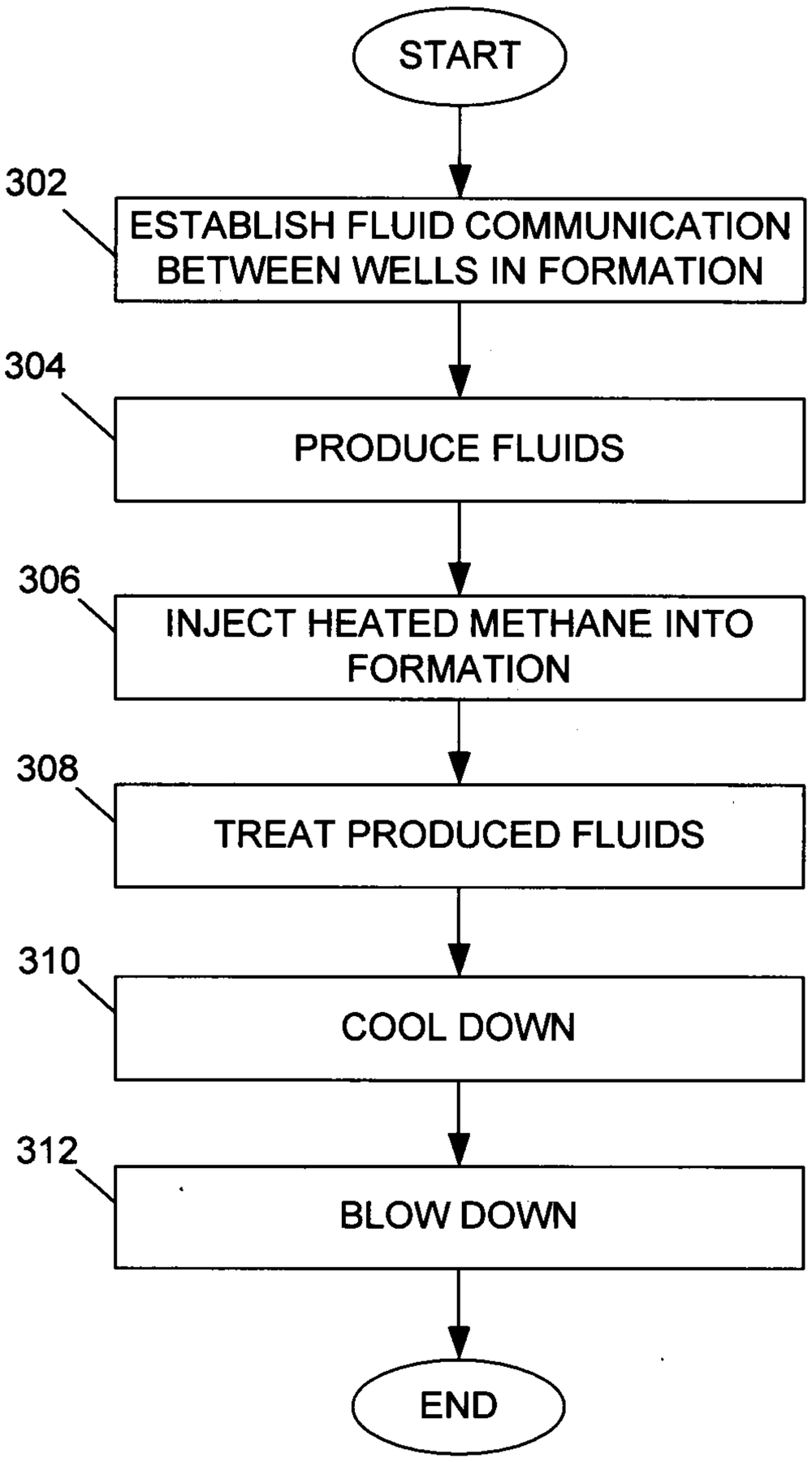

START
302
ESTABLISH FLUID COMMUNICATION BETWEEN WELLS IN FORMATION
304
PRODUCE FLUIDS
306
INJECT HEATED METHANE INTO FORMATION
308
TREAT PRODUCED FLUIDS
310
COOL DOWN
312
BLOW DOWN
END

FIG. 3

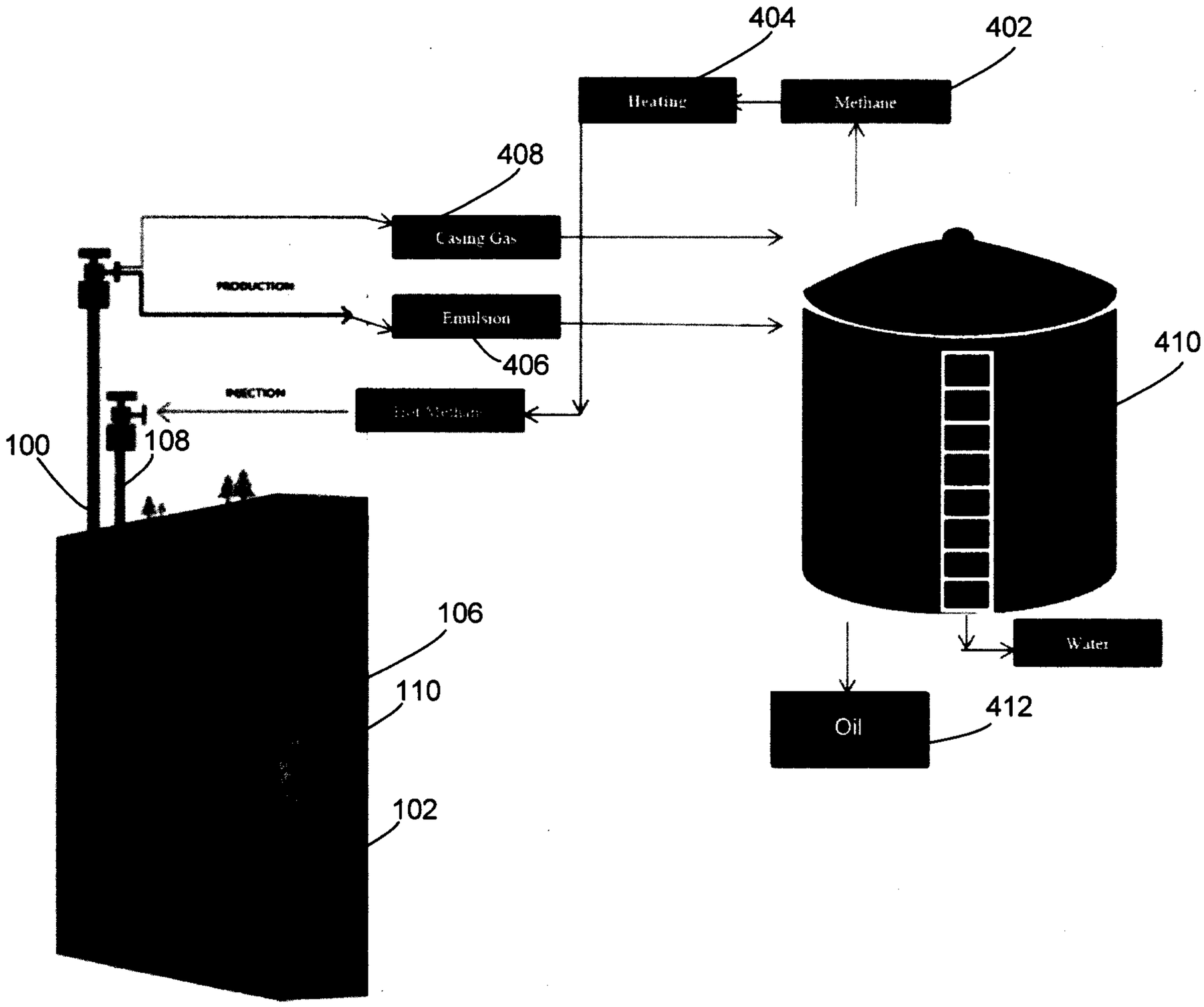

404
402
Heating
Methane
408
Casing Gas
PRODUCTION
Emulsion
406
INJECTION
100
108
106
110
102
410
Water
Oil
412

FIG. 4

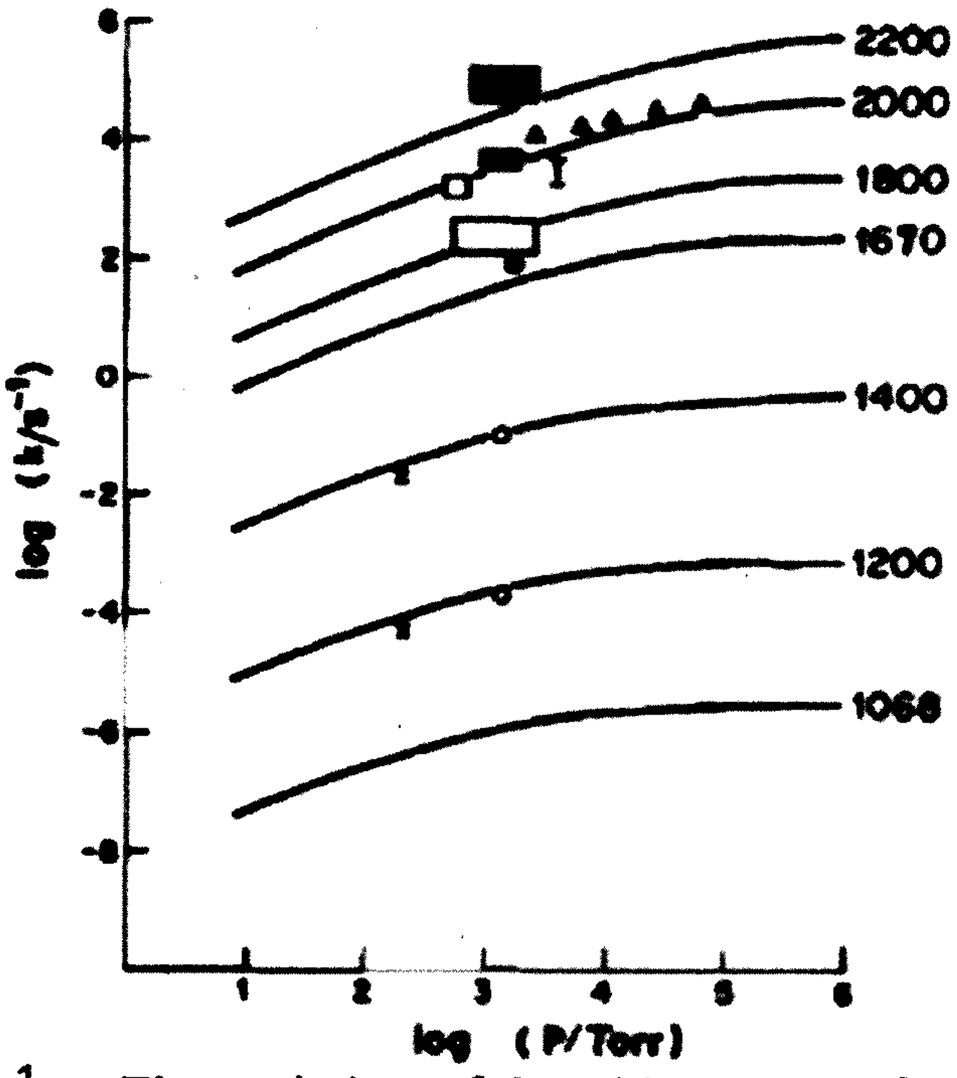
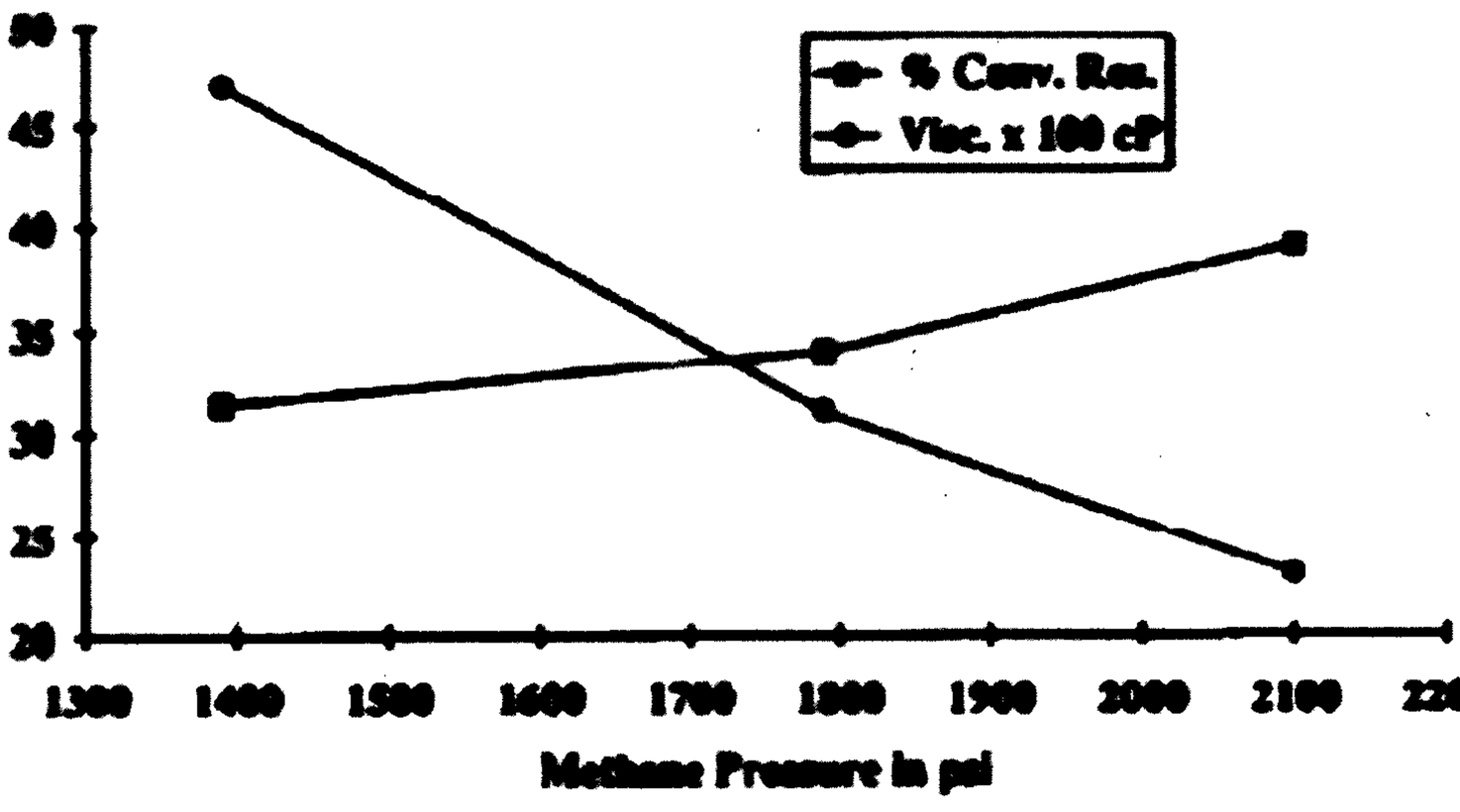


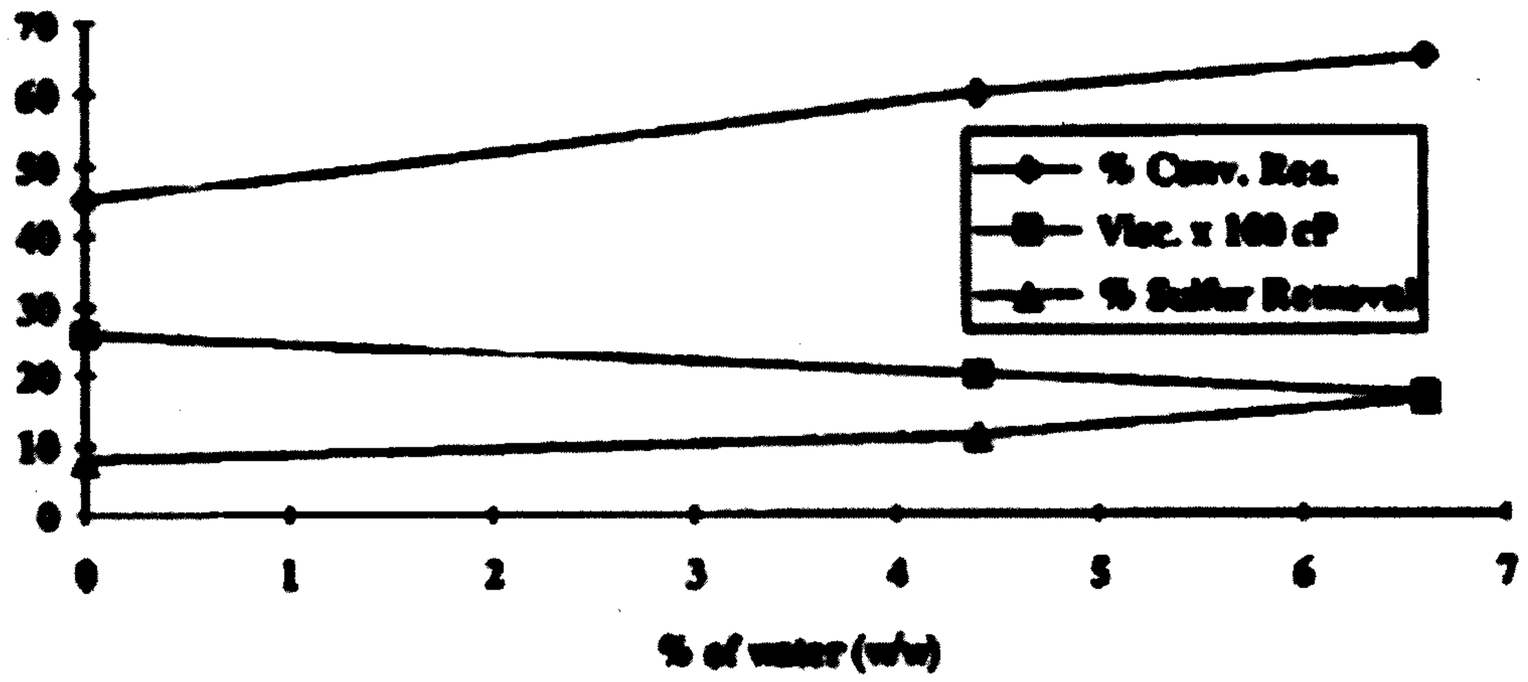
Fig. 1. **The variation of k_1 with pressure for temperatures up to 2200 K. The solid lines are calculated from [9] and the experimental results were obtained in shock-tube studies or flow-system pyrolysis. ○, ref. 11; ×, ref. 5; ●, ref. 10; □, ref. 23; I, ref. 24; ■, ref. 9; ▲ ref. 25.**

FIG. 5



1 Effects of methane pressure on percentage conversion of >540 C fraction and viscosity of the products. Reactions in a 4.5 l batch reactor at 380 C for 1 h. Water content of crude oil was 6.6 wt%. Average of three runs

FIG. 6



2 Effects of the water content on conversion of >540 C fraction, product viscosity and sulfur removal during methane upgrading at 380 C and 11 MPa for 4 h

FIG. 7

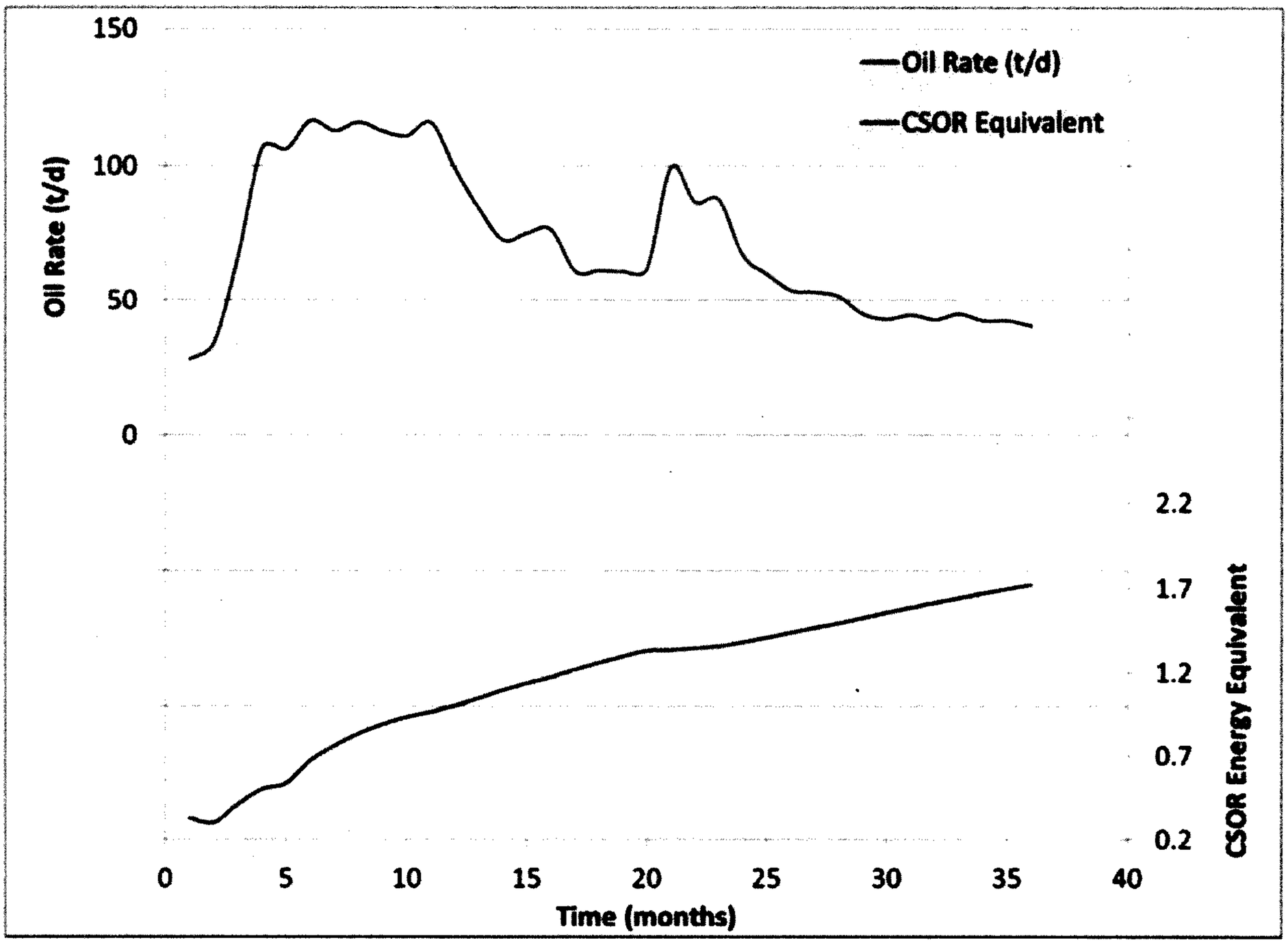
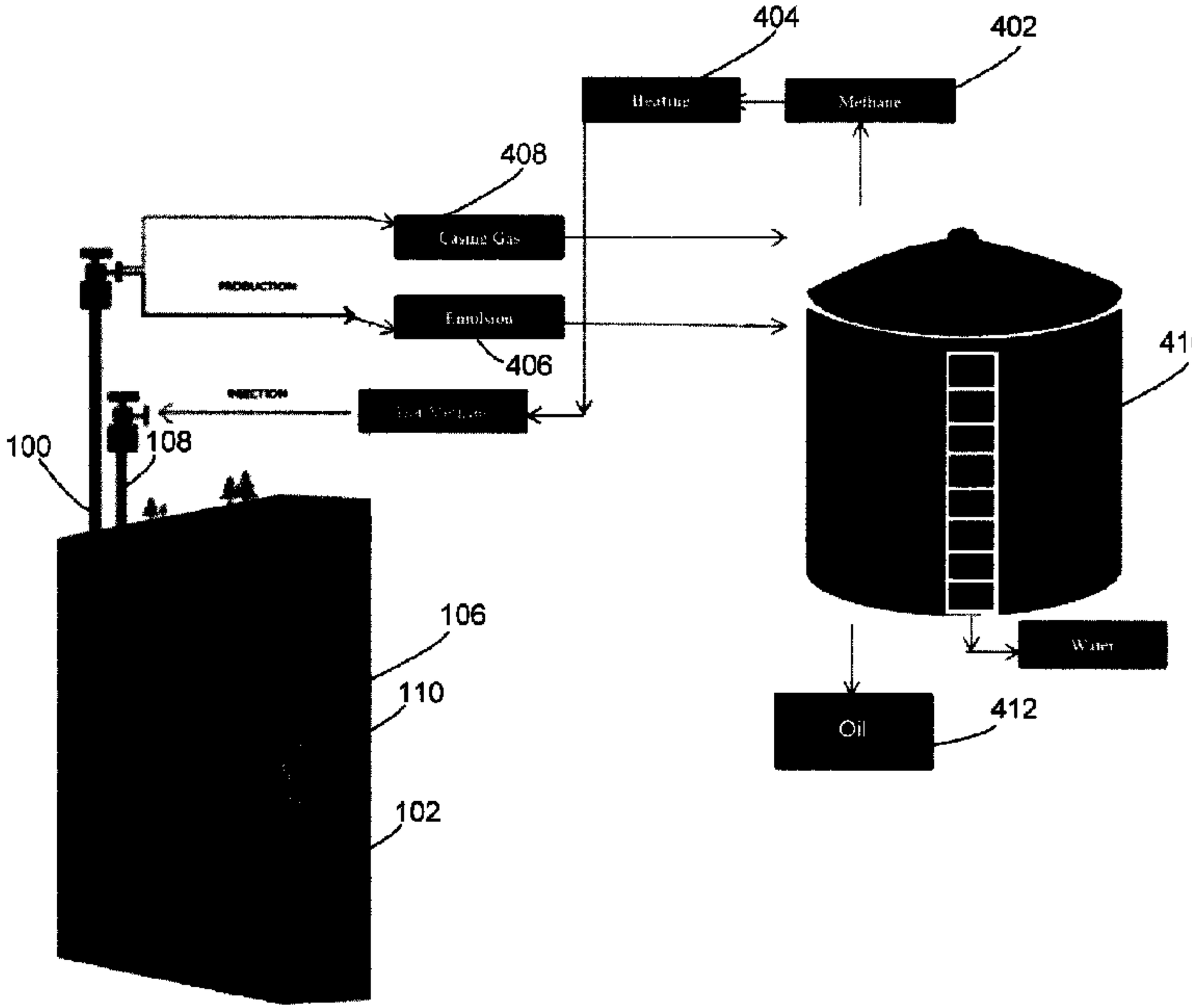


Figure 3: Oil Rate and CSOR (Equivalent) for Simulated System

FIG. 8


404
402
Heating
Methane
408
Casing Gas
PRODUCTION
Emulsion
406
410
INJECTION
100
108
106
110
102
Water
Oil
412