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SUPERINTENDENCIA DE INDUSTRIA Y COMERCIO

DIVISIÓN DE NUEVAS CREACIONES

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SUPERINTENDENCIA DE INDUSTRIA Y COMERCIO



No. 09-069914- -00011-0000

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Ref: Expediente No. 09-069.914

Solicitud de patente de invención titulada: "UN PROCESO MODIFICADO PARA LA RECUPERACIÓN DE HIDROCARBURO UTILIZANDO COMBUSTIÓN IN SITU"

Solicitante: ARCHON TECHNOLOGIES LTDA.

Opositora: PACIFIC RUBIALES ENERGY CORP.

SUSTENTO DE OPOSICIÓN SEGÚN ARTÍCULO 42 DE LA DECISIÓN 486

J. IAN RAISBECK, mayor de edad y vecino de Bogotá, identificado tal como aparece al pie de mi firma, en mi carácter de apoderado de la sociedad PACIFIC RUBIALES ENERGY CORP., cuyo poder adjunto al presente memorial, me permito presentar sustento de la oposición dentro del término establecido por el artículo 42 de la Decisión 486 en contra de la solicitud de patente de invención indicada en el epígrafe.

1. PETICIÓN

Que se declare fundada la presente oposición y en consecuencia se niegue el privilegio de patente de invención contenida en el expediente 09-069914, por incumplir los requisitos de patentabilidad exigidos por los artículos 14 y 18 de la Decisión 486.

2. LEGÍTIMO INTERÉS

A mi representada le asiste legítimo interés para presentar esta oposición, pues mi representada pertenece a la industria petrolera y no puede permitir que una solicitud de patente que no cumple con los requisitos de patentabilidad obtenga el privilegio de patente, limitando de manera injustificada el acceso a cierta tecnología de extracción de hidrocarburos y la libre competencia.

3. FUNDAMENTOS DE LA OPOSICIÓN

A. Los siguientes documentos son referenciados para sustentar la siguiente oposición:

REFERENCIA	DOCUMENTO	REQUERIMIENTO AFECTADO	FECHA DE PUBLICACIÓN
D1	US7581587	Nivel inventivo (Reivindicaciones 1, 2, 5, 9, 10, 11, 12)	8 Noviembre 2007
D2	US4598772	Nivel Inventivo (Reivindicaciones 1, 2, 5, 9, 10, 11, 12)	8 Julio 1986
D3	US4474237	Nivel inventivo (Reivindicación 2)	2 Octubre 1984
D4	US5626191	Nivel inventivo (Reivindicación 2, 5)	6 Mayo 1997
D5	US4598770	Nivel inventivo (Reivindicación 5)	8 Julio 1986
D6	WO 00/46484	Nivel inventivo (Reivindicación 5)	10 Agosto 2000
D7	WO 2004/007899	Nivel inventivo (Reivindicación 5)	22 Enero 2004
D8	US6318457	Nivel inventivo (Reivindicación 5)	20 Noviembre 2001
D9	WO 2007/095764	Nivel inventivo (Reivindicación 9)	30 Agosto 2007
D10	US6412557	Nivel inventivo (Reivindicación 11)	17 Junio 1999
D11	US4410042	Nivel inventivo (Reivindicación 12)	18 Octubre 1983
D12	US4042026	Nivel inventivo (Reivindicación 12)	16 Agosto 1977

B. i. La solicitud de patente colombiana objeto de la presente oposición, en adelante SPC 914, intenta solucionar el problema del impacto medioambiental creado por la recuperación de hidrocarburos así como el costo generado por los sistemas de combustión in situ denominados “punta a talón”, (Toe to Heel en inglés) el cual requiere

una técnica donde los pozos de producción e inyección se encuentran separados en sus respectivas plataformas, con largas distancias entre ellos, las cuales tienen que ser despejadas para permitir el paso de los conductos de gases, el transporte de personal, o para tener el equipo de producción de gases oxidantes en el pozo de inyección. La SPC 914 establece que el impacto medioambiental y los costos serían reducidos con la implementación de un sistema “talón a punta” (Heel to toe en inglés) donde el pozo de inyección se encuentre situado en la misma plataforma de perforación del pozo de producción, distancia y situación que denomina como “próximo”. Para reducir los peligros generados por combustión cerca al pozo de producción, la SPC 914 requiere que medios no oxidantes sean usados dentro de estos, con el fin de prevenir, por ejemplo, explosiones.

ii. La Reivindicación 1 de la SPC 914 específicamente reclama lo siguiente:

“1. Un proceso para la recuperación de hidrocarburos licuados o gasificados de un reservorio subterráneos de hidrocarburos que incluyen los pasos de:

(a) Proporcionar por lo menos un pozo de producción teniendo una pata horizontal sustancialmente posicionada relativamente bajo en dicho reservorio, dicha pata horizontal adaptada para permitir la entrada de hidrocarburo licuado al interior de dicha pata horizontal, teniendo de un lado de la misma una parte talón y en el lado opuesto de la misma una parte dedo, dicha pata horizontal, dicho pozo de producción teniendo una sección vertical sustancialmente conectada a dicha pata horizontal cercana a dicha parte talón del mismo;

(b) Proporcionar tubería de inyección en el interior de dicho pozo de producción extendiéndose dentro de dicha sección vertical y dentro, por lo menos una parte, de dicha parte horizontal para recoger dichos hidrocarburos licuados que fluyen a dicha pata horizontal;

(c) Inyectar un medio dentro de un pozo de producción, en donde tal medio es escogido de un pozo de medios incluyendo individualmente o en combinación, un gas no oxidante, vapor, agua, o dióxido de carbono;

(d) Proporcionar un gas oxidante a dicho reservorio subterráneo, por lo menos inicialmente en un lugar en, o cercano, a dicha sección vertical de dicho pozo de producción;

(e) Encender el hidrocarburo en dicho reservorio de hidrocarburo cerca de dicha sección vertical de dicho pozo de producción de tal manera que cause la combustión de una parte de dicho hidrocarburo en dicho reservorio de hidrocarburo cerca de dicha sección vertical y de ese modo crear un frente de

combustión que avance exteriormente y lejos de dicho pozo de inyección por lo menos en la dirección a lo largo de dicha pata horizontal y hacia dicha parte dedo del mismo;

(f) Causar que el hidrocarburo licuado caliente de dicho reservorio drene de las partes superiores del mismo y se acumule en dicha pata horizontal; y

(g) Extraer del pozo de producción, por vía de dicha tubería de producción, dicho hidrocarburo que ha fluido a dicha pata horizontal.

La anterioridad D1 describe un método de recuperación de hidrocarburos usando combustión in situ que comprende un pozo de producción y un pozo de inyección en la misma plataforma de perforación en un sistema “talón a punta” (ver figura 2 y resumen de la invención). D1 adicionalmente establece que el utilizar una única plataforma para perforar los pozos productor e inyector reduce el impacto medioambiental (ver columna 2, líneas 6 a 9). Esto quiere decir que D1 ya había elucidado el problema del impacto medioambiental anteriormente y había proporcionado una solución que es la misma que la presentada en la SPC 914. D1, y haciendo referencia particular a la figura 2 contenida en este, describe claramente un proceso de recuperación de hidrocarburos que contempla todas las etapas mostradas en la Reivindicación 1 de la SPC 914, con excepción de la etapa (c), la cual hace referencia a la inyección de un medio no oxidante dentro del pozo de producción.

Aunque D1 no muestra el uso de un medio no oxidante para aumentar la presión de la porción horizontal del pozo de producción, lo que mantiene el gas oxidante fuera de este, lo anterior se considera un aspecto técnico obvio para una persona medianamente versada en el arte en dos maneras: La primera, la anterioridad D2 devela previamente el uso de medios no oxidantes en el fondo del pozo de producción con el fin de prevenir explosiones en sistemas de recuperación de combustión in situ, así como la reducción por parte de este tipo de medios de la concentración de gas oxidante en el pozo de producción. La segunda, y en relación al incremento de presión en el pozo productor para impedir la entrada de gas oxidante en el pozo de producción, esto es claramente obvio para una persona medianamente versada en la materia, pues el incremento de la presión de un gas en cualquier punto de un conducto reduce la posibilidad que otro gas entre a dicho conducto.

En consecuencia la etapa (c) de la SPC 914 sería obvia para cualquier persona medianamente versada en la materia, lo cual le resta nivel inventivo a la Reivindicación 1, y por lo tanto, no es patentable.

iii. La Reivindicación 2 de la SPC 914, se encuentra dirigida al uso de perforaciones en el pozo de inyección para aportar el gas oxidante.

El uso de estas perforaciones hace parte del estado de la técnica, siendo ilustradas en D3 (ver elementos 40) y D4 (ver elementos 112), por lo que esta característica no le imprime nivel inventivo a lo reclamado en la Reivindicación 2.

iv. La Reivindicación 5 de la SPC 914 está dirigida a la perforación del pozo de inyección próximo de la sección vertical del pozo productor. Adicionalmente el pozo de inyección puede ser vertical, inclinado u horizontal.

Como se señaló anteriormente, D1 revela la configuración a través de la cual el pozo de producción y el pozo de inyección se encuentran en la misma plataforma, es decir “próximos” (ver columna 2, líneas 6 a 9 y Reivindicación 6). En cuanto a las diferentes posibilidades de configuración del pozo de inyección tales como vertical, horizontal o inclinado, éstas son bien conocidas en el estado de la técnica, como lo evidencian las anterioridades D5 (ver columna 2, líneas 49 a 53), D6 (todo el documento) D7 (todo el documento) y D8 (todo el documento).

v. La Reivindicación 9 de la SPC 914 está dirigida a la adición de un diluyente de hidrocarburo condensado al medio no oxidante del método de la Reivindicación 1.

Esta característica ha sido previamente develada por D9 (ver página 2, línea 9 a 13, y Reivindicación 1 paso (c)), por lo que no provee características técnicas que le impriman a esta reivindicación nivel inventivo.

vi. La Reivindicación 10 de la SPC 914 está dirigida a mostrar que el medio no oxidante usado en las Reivindicaciones 1, 7 y 8 provee una presión positiva la cual previene el ingreso del gas oxidante dentro de la porción horizontal del pozo productor.

Como se dijo anteriormente, la utilización de un medio no oxidante se enseña previamente en D2 (ver todo el documento), y es propio del estado de la técnica; además, que la presión positiva creada por la inyección de gas no oxidante en el pozo productor prevenga el ingreso de gas oxidante al mismo, hace referencia a conocimientos generales comúnmente conocidos por una persona medianamente versada en la materia, puesto que al proporcionar presión positiva en un punto de un conducto, se evita o limita la entrada de otros gases al mismo. Por ende, la Reivindicación 10 no es patentable.

vii. La Reivindicación 11 de la SPC 914 depende de las Reivindicaciones 1 a 8 y adiciona al método allí contenido el uso de un catalizador *"colocado en o alrededor de la pata horizontal del pozo de producción"*.

El uso de dicho catalizador para conseguir el ascenso del hidrocarburo, forma parte del estado de la técnica que se devela, por ejemplo, en D10 (ver elemento 11). Así las cosas, esta característica no le imprime nivel inventivo a las anteriores reivindicaciones y no es patentable.

viii. La Reivindicación 12, la cual depende de las Reivindicaciones 1 a 8, especifica los componentes de la mezcla del medio oxidante, siendo estos oxígeno/dióxido de carbono.

Esta mezcla se ha contemplado anteriormente en los procesos de recuperación de hidrocarburos que utilizan sistemas de combustión in situ, ej. D11 (ver columna 1, línea 60 a columna 2, línea 18), D12 (ver columna 4, líneas 14 a17). Por lo tanto la Reivindicación 12 carece de nivel inventivo.

ix. Finalmente queremos llamar la atención del Examinador a la Reivindicación 1 numeral (b) en donde existe un error de traducción; la traducción al español de ésta dice:

(b) *"proporcionar tubería de inyección en el interior de dicho pozo de producción extendiéndose dentro de dicha sección vertical y dentro, por lo menos de una parte, de dicha parte horizontal para recoger dichos hidrocarburos licuados que fluyen a dicha pata horizontal"*

En la versión original en inglés de este mismo numeral de la Reivindicación 1 se divulga lo siguiente:

(b) "*providing production tubing inside said production well extending within said vertical section and within at least a portion of said horizontal portion to collect said liquefied hydrocarbon which flows into said horizontal leg.*"

Comparando los dos textos mencionados anteriormente se evidencia que existe un error de traducción ya que en español dice "**tubería de inyección**" cuando debería decir "**tubería de producción**". Es importante que dicho error sea corregido para no afectar la claridad ni la cobertura de las reivindicaciones.

5. FUNDAMENTOS DE DERECHO

Son fundamentos de derecho de la presente oposición los artículos 14, 18 y 42 de la Decisión 486 de la Comunidad Andina.

6. PRUEBAS

- a. Copia del documento US 7,581,587
- b. Copia del documento US 4,598,772
- c. Copia del documento US 4,474,237
- d. Copia del documento US 5,626,191
- e. Copia del documento US 4,598,770
- f. Copia del documento WO 00/46484
- g. Copia del documento WO 2004/007899
- h. Copia del documento US 6,318,457
- i. Copia del documento WO 2007/095764
- j. Copia del documento US 6,412,557

- k. Copia del documento US 4,410,042
- l. Copia del documento US 4,042,026

7. ANEXOS

- a. Copia de traslado al solicitante.
- b. Los mencionados en el acápite de pruebas.

8. NOTIFICACIONES

- a. Mi representada recibirá notificaciones en la Calle 98 No. 18 – 71, Oficina 602.
- b. El suscrito recibirá notificaciones en la Calle 98 No. 18 – 71, Oficina 602.

Atentamente,



J. IAN RAISBECK
CC. No. 79.376.996 de Bogotá
T.P. 135.799 CSJ



US007581587B2

(12) **United States Patent**
Pfefferle

(10) **Patent No.:** **US 7,581,587 B2**
(45) **Date of Patent:** **Sep. 1, 2009**

(54) **METHOD FOR IN-SITU COMBUSTION OF
IN-PLACE OILS**

(56)

References Cited

U.S. PATENT DOCUMENTS

(75) Inventor: **William C. Pfefferle**, Madison, CT (US)

(73) Assignee: **Precision Combustion, Inc.**, North
Haven, CT (US)

(*) Notice: Subject to any disclaimer, the term of this
patent is extended or adjusted under 35
U.S.C. 154(b) by 251 days.

(21) Appl. No.: **11/646,002**

(22) Filed: **Dec. 27, 2006**

(65) **Prior Publication Data**

US 2007/0256833 A1 Nov. 8, 2007

Related U.S. Application Data

(60) Provisional application No. 60/756,020, filed on Jan.
3, 2006.

(51) **Int. Cl.**

E21B 43/243 (2006.01)

E21B 43/30 (2006.01)

(52) **U.S. Cl.** **166/245; 166/256; 166/257;**
166/272.1; 166/272.7; 166/306

(58) **Field of Classification Search** **166/272.7;**
166/306

See application file for complete search history.

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3,565,174 A *	2/1971	Parker et al.	166/261
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5,626,191 A *	5/1997	Greaves et al.	166/245
6,016,868 A *	1/2000	Gregoli et al.	166/261

* cited by examiner

Primary Examiner—George Suchfield

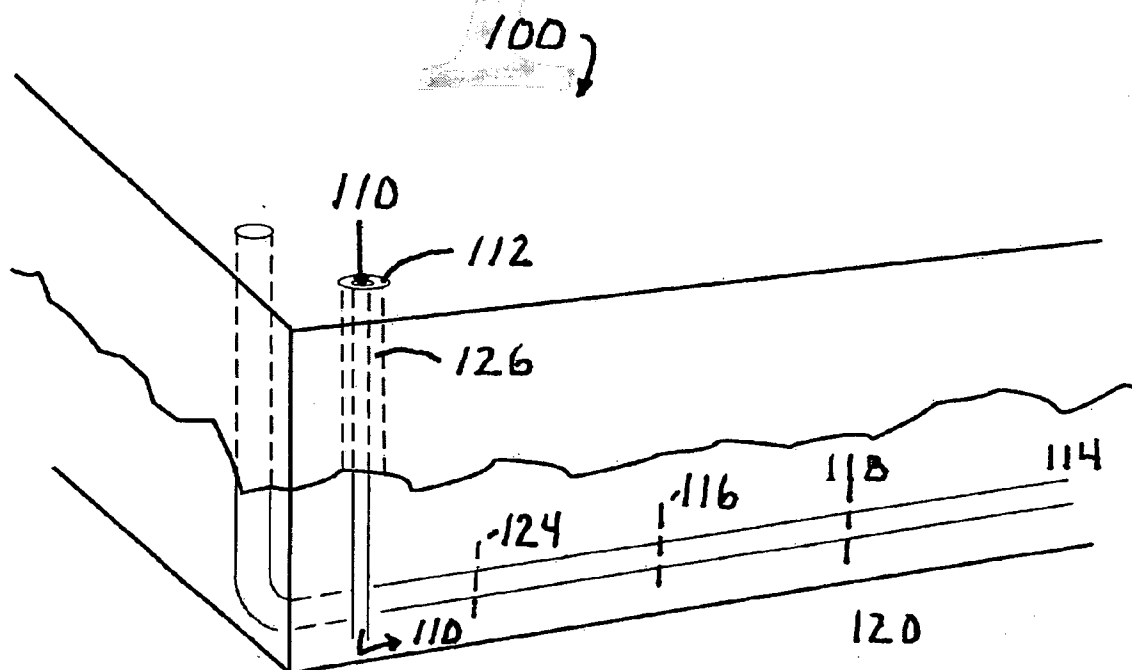
(74) *Attorney, Agent, or Firm*—Robert L. Rispoli

(57)

ABSTRACT

A novel method is provided for in situ combustion and recovery of oil from underground reservoirs including injecting air into the reservoir at a region near the reservoir floor; withdrawing combustion products from a region near the reservoir ceiling, and collecting oil from a horizontal production well near the reservoir floor.

9 Claims, 2 Drawing Sheets



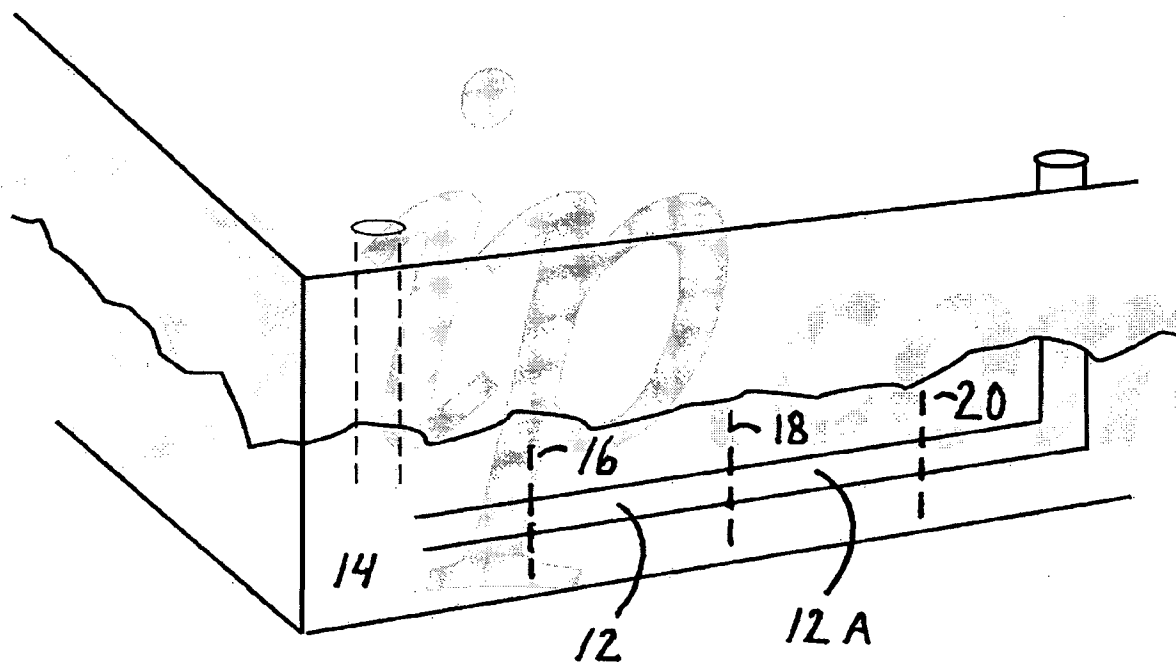


FIGURE 1 - PRIOR ART

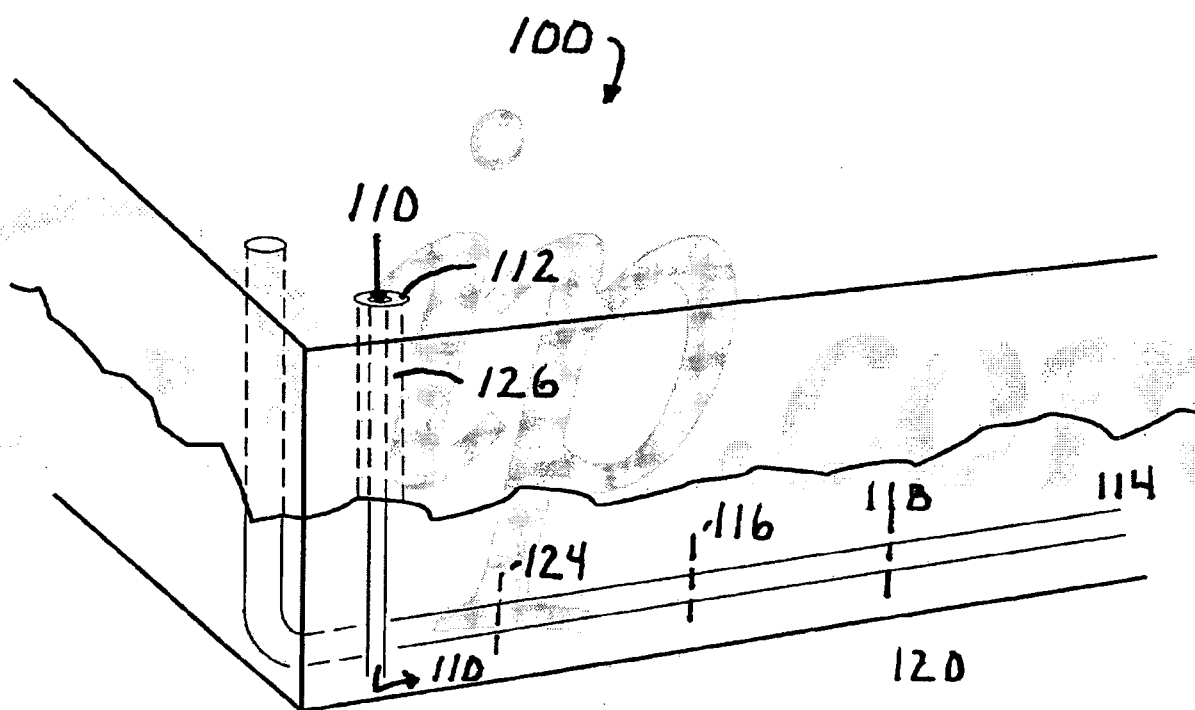


FIGURE 2

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METHOD FOR IN-SITU COMBUSTION OF IN-PLACE OILS

CROSS-REFERENCE

This application claims the benefit of U.S. Provisional Application No. 60/756,020 filed Jan. 3, 2006.

FIELD OF THE INVENTION

This invention relates to a method for contacting carbonaceous deposits in a sub-surface formation with a reactive fluid whereby such deposits may be mobilized thus allowing for recovery. More specifically, the invention relates to a method for efficient recovery and upgrading of heavy oils.

BACKGROUND OF THE INVENTION

In-situ combustion is an established method for enhanced oil recovery. In a typical application, air is injected into a vertical well resulting in combustion and increased oil mobility. Product oil is then recovered via either the injection well by a process known as huff-and-puff or via a second vertical well. The process is not widely used because it has been difficult to control. Thus attempts have been made to improve the process.

To reduce the problem of gravity segregation, for example, air is injected at a high point of the reservoir: U.S. Pat. No. 5,211,230 teaches injecting air at a high point of the reservoir via a vertical well along with a lower horizontal production well. U.S. Pat. No. 5,626,191 teaches placing the low horizontal well perpendicular to the vertical well to draw the combustion front along the horizontal well and away from the injection well. Although this is an improvement, combustion products are intended to be removed with the heated oil and thus injected fresh air also has ready access to the horizontal well between the toe and the combustion front. A further disadvantage is that the injection well and the horizontal well vertical leg must be located far apart. Accordingly, there is still a need for a process which is controllable and provides efficient use of injected air.

SUMMARY OF THE INVENTION

It is an object of the present invention to provide an improved method of contacting an injected fluid with a reaction front whereby oil may be recovered economically. More specifically, it is a further object of the present invention to enable more efficient in-situ combustion of in-place heavy oil whereby combustion products are more efficiently removed from the combustion zone and thermal cracking is promoted.

In the present invention, air is injected near the reservoir floor allowing the hot combustion products to over-ride the cooler fresh air. The cooler air is thus drawn to the combustion front aided by withdrawal of combustion products via a bleed well located at a point well above the reservoir floor. Use of a horizontal bleed well permits steering of combustion front travel. Advantageously, oil is recovered via a horizontal production well having its heel (the transition from horizontal to vertical rise to the surface) near the injection well. This means that the production well can be maintained liquid full throughout the air rich burned out zone blocking loss of injected air.

Combustion product gases may be withdrawn from a region near the top of the reservoir, preferably at an elevated pressure near the reservoir pressure. Passage of the withdrawn gases through a power turbine allows recovery of a

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portion of the energy required for compression of the injection air. Combustion of fuel to utilize oxidant in the withdrawn gases increases power output of the power turbine. Fresh air may be added as necessary to combust fuel values present in the combustion products.

An advantage of the present invention is that the oil recovery well(s) may be drilled from the same platform as the injection and bleed wells thereby reducing the environmental impact. Multiple production wells may be utilized depending upon the reservoir geometry. Typically, it will be advantageous to place the injection well at a low point in the reservoir. In addition, the required wells need not terminate directly under the production platform. If desired, injection and production wells may be drilled from separate platforms located some distance apart with the production well toe (i.e., horizontal terminus) located near the injection well.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a schematic representation of the state of the art system of U.S. Pat. No. 5,626,191.

FIG. 2 is a schematic representation of the present invention.

DESCRIPTION OF THE INVENTION

FIG. 1 depicts an advanced design in-situ combustion system of the prior art. Unlike the system of the present invention, excess combustion gases are withdrawn via the horizontal production well 12. Thus the horizontal section 12A of well 12 that lies within burned out zone 14 cannot withdraw combustion gases without preferentially bleeding off fresh air. As the combustion front progresses from location 16 through representative locations 18, 20, etc., loss of fresh combustion air worsens. To minimize fresh air loss, the toe section may be at a lower elevation than the heel so that the leg between the toe and the combustion front remains liquid full. This also allows oil to drain out of the toe into the reservoir. Even so, this is only a partial solution since hot gases will still tend to over-ride the cooler fresh air at the withdrawal point. The result is energy loss.

Referring to the drawings, FIG. 2 depicts a well pattern 100 for in-situ combustion according to the present invention. Air 110 is injected via well 112 at the bottom of reservoir 114 flowing to combustion front 116. Heated oil 118 drains to the reservoir floor on rock bed 120 and is withdrawn at a controlled rate such that horizontal well 122 is liquid full throughout burned out zone 124. Hot combustion gases rise at combustion front 116 and are withdrawn via concentric well 126 for energy recovery in a turbine (not shown). Well 126 need not be concentric with injection well 112 and may be located as the reservoir structure dictates or may be a horizontal well. Regardless, it is typically advantageous to drill all wells from a common platform.

While the present invention has been described in considerable detail, other configurations exhibiting the characteristics taught herein for a method for in-situ combustion of in-place oils are contemplated. Therefore, the spirit and scope of the invention should not be limited to the description of the preferred embodiments described herein.

The invention claimed is:

1. A method of in-situ combustion for recovery of oil from an underground oil reservoir comprising:

a) injecting air into the reservoir via an injection well in a region near the reservoir floor;

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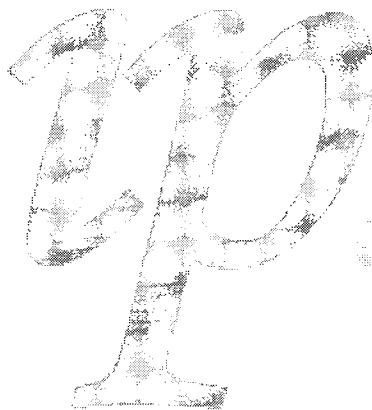
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- b) establishing a combustion front wherein hot combustion gases rise at the combustion front with combustion progressing from heel to toe;
 - c) withdrawing combustion products from a region near the reservoir ceiling whereby heated oil drains to the reservoir floor; and
 - d) collecting oil from a horizontal production well near the reservoir floor whereby the horizontal production well defines a heel proximate to the injection well.
2. The method of claim 1 wherein combustion products are withdrawn through a bleed well located above an air injection well flow exit.
3. The method of claim 2 wherein the bleed well includes a horizontal section perpendicular to a vertical injection well.

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4. The method of claim 1 wherein withdrawn combustion products are passed to an expansion turbine for energy recovery.
5. The method of claim 4 wherein fuel is combusted to heat the combustion products before expansion.
6. The method of claim 1 wherein the production well is drilled from the same platform as an air injection well.
7. The method of claim 1 wherein the toe of the production well is at a higher elevation than the heel.
8. The method of claim 1 wherein the production well is a horizontal well perpendicular to an injection well.
9. The method of claim 1 wherein combustion products are withdrawn through multiple bleed wells.

* * * * *



United States Patent [19]

Holmes

[11] Patent Number: 4,598,772

[45] Date of Patent: Jul. 8, 1986

[54] METHOD FOR OPERATING A PRODUCTION WELL IN AN OXYGEN DRIVEN IN-SITU COMBUSTION OIL RECOVERY PROCESS

[75] Inventor: Billy G. Holmes, Lancaster, Tex.

[73] Assignee: Mobil Oil Corporation, New York, N.Y.

[21] Appl. No.: 566,373

[22] Filed: Dec. 28, 1983

[51] Int. Cl.⁴ E21B 43/243; E21B 47/06

[52] U.S. Cl. 166/251; 166/53; 166/64; 166/261

[58] Field of Search 166/53, 57, 64, 251, 166/256, 261, 263, 302

[56] References Cited

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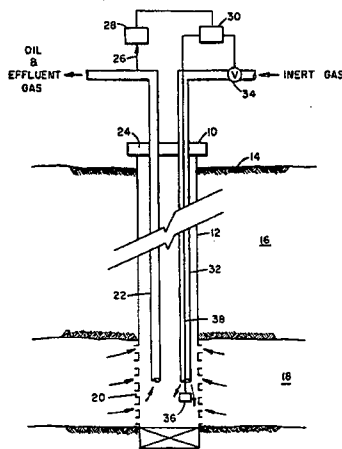
4,474,237 10/1984 Shu 166/261

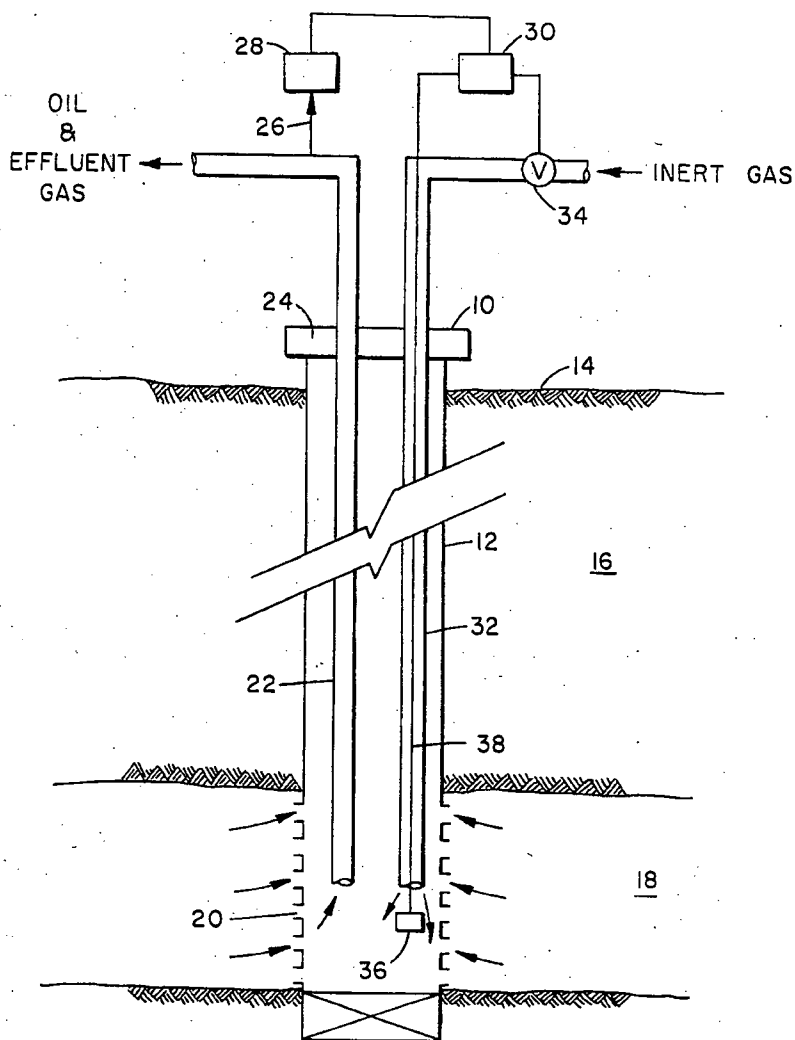
Primary Examiner—George A. Suchfield
Attorney, Agent, or Firm—Alexander J. McKillop;
Michael G. Gilman; Charles J. Speciale

[57] ABSTRACT

A method for operating a production well during an oxygen driven in-situ combustion oil recovery process comprising continuously injecting an inert gas such as nitrogen or carbon dioxide into the bottom of the production well at a predetermined low injection rate, preferably 0.1 to 2 MSCF/day, and continuously monitoring the oxygen concentration of the produced effluent gas and the bottomhole temperature of the production well. In the event that the oxygen content of the effluent gas increases to a value within the range of 5 to 20 volume percent or the bottomhole temperature of the production well increases to a value within the range of 200° to 300° F., the injection rate of the inert gas into the bottom of the production well is increased to a maximum rate until the oxygen concentration of the effluent gas and the bottomhole temperature are reduced to a safe level.

8 Claims, 1 Drawing Figure





METHOD FOR OPERATING A PRODUCTION WELL IN AN OXYGEN DRIVEN IN-SITU COMBUSTION OIL RECOVERY PROCESS

BACKGROUND OF THE INVENTION

This invention relates to an in-situ combustion recovery process within a subterranean, oil-containing formation using high concentrations of oxygen and more particularly to a method for operating a production well in such processes wherein a small amount of an inert gas is continuously injected into the bottom of the well which may be increased to a maximum rate if either the bottomhole temperature of the well or the oxygen content of the effluent gas from the well reach an unsafe level indicating a hazardous condition in the well.

Thermal recovery techniques, in which hydrocarbons are produced from carbonaceous strata such as oil sands, tar sands, oil shales, and the like by the application of heat thereto, are becoming increasingly prevalent in the oil industry. Perhaps the most widely used thermal recovery technique involves in-situ combustion or "fire flooding". In a typical fire flood, a combustion zone is established in a carbonaceous stratum and propagated within the stratum by the injection of air, oxygen-enriched air or pure oxygen through a suitable injection well. As the combustion supporting gas is injected, products of combustion and other heated fluids in the stratum are forced away from the point of injection toward production zones where they are recovered from the stratum and withdrawn to the surface through suitable production wells. U.S. Pat. Nos. 3,240,270-Marx, 4,031,956-Terry, and 4,042,026-Pusch et al are examples of the recovery of oil by in-situ combustion.

In such processes, the prevention of unintended ignition due to the hazardous nature of using pure oxygen is of primary concern. For example, as the combustion zone moves away from the injection well, a large volume of unreacted oxygen sometimes accumulates near the well. If this travels upwardly in the well, a catastrophic fire possibly destroying the well, can be ignited. U.S. Pat. No. 3,125,324-Marx discusses the ignition problem. In addition, U.S. Pat. No. 4,042,026 to Pusch et al disclosed above also discusses the hazardous nature of using pure oxygen in in-situ combustion operations that could lead to uncontrolled reactions or explosions.

U.S. Pat. No. 3,240,270 to Marx discloses an in-situ combustion process for the recovery of oil wherein an inert cooling fluid such as water, nitrogen, or carbon dioxide is injected into the production boreholes so as to maintain the temperature therein below combustion supporting temperature at the oxygen concentration therein and prevent borehole fires.

U.S. Pat. No. 3,135,324 to Marx discloses an in-situ combustion process for recovery of oil wherein a fine dispersion of water is injected with the combustion supporting gas in a sufficient amount to maintain the temperature of the stratum around the injection well below ignition temperature.

It is an object of the present invention to provide a method for safely operating a production well in an in-situ combustion oil recovery operation using high concentrations of oxygen.

SUMMARY OF THE INVENTION

The present invention relates to a method for recovering viscous oil from a subterranean, viscous oil-containing formation penetrated by at least one injection well and one production well and having fluid communication therebetween comprising establishing an in-situ combustion operation in the formation by injecting substantially pure oxygen into the formation via the injection well and recovering fluids including oil and an effluent gas from the formation via the production well, continuously injecting an inert gas such as nitrogen or carbon dioxide at a predetermined low injection rate, preferably 0.1 to 2 MSCF/day, into the lower portion of the production well, continuously analyzing the effluent gas for oxygen concentration and monitoring the bottomhole temperature of the production well, and increasing the injection rate of said inert gas to a maximum rate if the oxygen concentration of said effluent gas increases to a predetermined concentration, preferably 5 to 20 volume percent, or if the bottomhole temperature of the production well increases to a predetermined temperature, preferably within the range of 200° to 300° F.

BRIEF DESCRIPTION OF THE DRAWING

The drawing shows a completion for a production well in accordance with the present invention.

DESCRIPTION OF THE PREFERRED EMBODIMENT

The present invention provides a method for operating a production well in an oxygen driven in-situ combustion oil recovery process to prevent production well fires or downhole explosions due to the presence of an unsafe amount of oxygen in the fluids produced from the production well or a high temperature in the bottom of the well. In a conventional forward in-situ combustion operation, an oxygen-containing gas such as air, oxygen-enriched air or essentially pure oxygen is introduced into the formation via an injection well and combustion of the in-place crude adjacent the injection well is initiated by one of many known means, such as the use of a downhole gas-fired heater or a downhole electric heater or chemical means. Thereafter, the injection of the oxygen-containing gas or pure oxygen is continued so as to maintain a combustion front which is formed, and to drive the front through the formation, heating and displacing crude petroleum ahead of it toward the production well from which fluids including oil and effluent gas are recovered. If oxygen by-passes the combustion and appears in the production well, uncontrolled borehole fires or explosions could occur, especially in the case where essentially pure oxygen is utilized to support the in-situ combustion operation.

Referring to the drawing, there is shown a production well 10 provided with a casing 12 extending from the surface 14 of the earth through the overburden 16 and into an oil-containing formation 18 from which oil is recovered by an oxygen driven in-situ combustion process. The production well 10 is in fluid communication with a substantial portion of the formation 18 by means of perforations 20. A production tubing 22 extends from the bottom portion of production well 10 adjacent the formation 18 through well head 24 for recovering fluids including oil and effluent gas from the formation. A portion of the effluent gas is withdrawn from tubing 22 through line 26 and passed into a gas

analysis means 28 to continuously analyze the oxygen content of the effluent gas recovered from the well. The oxygen analyzer sends signals to controller 30 in response to the oxygen content of the effluent gas.

An inert gas conduit 32 extends to a level in the bottom of the production well 10 adjacent the lower end of tubing 22. Conduit 32 passes through well head 24 and connects with a supply source of an inert gas such as nitrogen or carbon dioxide. A motor valve 34 is positioned in line 32 to control the fluid flow therein. Thermocouple 36, positioned in the bottom of production well 10 below conduit 32, sends signals via a suitable communication channel such as cable 38 to controller 30 in response to certain temperature conditions within the bottom of the well. Controller 30 functions to regulate motor valve 34 to control the amount of nitrogen or carbon dioxide injected into the bottom of the well via conduit 32 in response to the bottomhole production well temperature or the oxygen content of the effluent gas removed from tubing 22. Suspending the temperature sensing element 36 on cable 38 disposed within conduit 32 enables the sensing element to be easily replaced if it becomes inoperative.

During the in-situ combustion process, the oxygen content of the effluent gas in tubing 22 is constantly analyzed by analyzer 28 and the bottom hole temperature of the well is constantly monitored by thermocouple 36. In addition, during production, a stream of inert gas such as nitrogen or carbon dioxide is continuously injected at a predetermined low injection rate, preferably 0.1 to 2 MSCF/day, into the lower portion of the production well 10 via conduit 32. The rate of injection of inert gas through conduit 32 is controlled by motor valve 34. When the gas analysis means 28 indicates that the oxygen content of the effluent gas from production tubing 22 is within the range of 5 to 20 volume percent or when the bottomhole temperature sensed by thermocouple 36 is within the range of 200° to 300° F., controller 30 opens motor valve 34 and increases the flow rate of the inert gas to a maximum rate consistent with the pressure limitations of the formation. Production and injection of the inert gas is continued at the maximum rate until the oxygen content of the effluent gas is reduced to a safe level, preferably below 5 volume percent, and the bottomhole temperature is below 200° F. In addition, when the injection rate of the inert gas is increased to a maximum rate, the production well 10 may be shut-in and injection of oxygen into the formation via the injection well to support in-situ combustion may be terminated or reduced. Once the bottomhole temperature is below 200° F. and the oxygen content of the effluent gas from the production well is below 5 volume percent oxygen, injection of the inert gas is reduced to the predetermined low injection rate and production is continued.

Continuous injection of a small amount of inert gas into the bottom of the production well during production ensures instant availability of the gas in the event of a hazardous condition in the well.

While a particular embodiment of this invention has been shown and described, various modifications are within the true spirit and scope of the invention. The appended claims are, therefore, intended to cover all modifications.

What is claimed is:

1. A method for recovering viscous oil from a subterranean, viscous oil-containing formation penetrated by at least one injection well and one production well and having fluid communication therebetween comprising:

- a. establishing an in-situ combustion operation in the formation by injecting substantially pure oxygen into the formation via the injection well and recovering fluids including oil and an effluent gas from the formation via the production well;
 - b. continuously injecting nitrogen at a predetermined low injection rate into the lower portion of the production well;
 - c. continuously analyzing the effluent gas for oxygen concentration and monitoring the bottomhole temperature of the production well;
 - d. increasing said injection rate of said nitrogen gas to a maximum rate in the event the oxygen concentration of said effluent gas increases to a predetermined concentration or the bottomhole temperature increases to a predetermined temperature indicating a hazardous condition; and
 - e. continuing injection of said nitrogen at a maximum rate until the oxygen concentration of the effluent gas and the bottomhole temperature are reduced to a safe level.
2. The method of claim 1 wherein the injection rate of the nitrogen is increased to a maximum rate when the oxygen content of the effluent gas is within the range of 5 to 20 volume percent or the bottomhole temperature of the production well is within the range of 200° to 300° F.
3. The method of claim 1 further including shutting-in the production well when the injection rate of the nitrogen is increased to a maximum rate.
4. The method of claim 1 wherein the injection rate of the nitrogen during step (b) is 0.1 to 2 MSCF/day.
5. A method for recovering viscous oil from a subterranean, viscous oil-containing formation penetrated by at least one injection well and one production well and having fluid communication therebetween comprising:
- a. establishing an in-situ combustion operation in the formation by injecting substantially pure oxygen into the formation via the injection well and recovering fluids including oil and an effluent gas from the formation via the production well;
 - b. continuously injecting carbon dioxide at a predetermined low injection rate into the lower portion of the production well;
 - c. continuously analyzing the effluent gas for oxygen concentration and monitoring the bottomhole temperature of the production well;
 - d. increasing said injection rate of said carbon dioxide to a maximum rate in the event the oxygen concentration of said effluent gas increases to a predetermined concentration or the bottomhole temperature increases to a predetermined temperature indicating a hazardous condition; and
 - e. continuing injection of said carbon dioxide at a maximum rate until the oxygen concentration of the effluent gas and the bottomhole temperature are reduced to a safe level.
6. The method of claim 5 wherein the injection rate of the carbon dioxide is increased to a maximum rate when the oxygen content of the effluent gas is within the range of 5 to 20 volume percent or the bottomhole temperature of the production well is within the range of 200° to 300° F.
7. The method of claim 5 further including shutting-in the production well when the injection rate of the carbon dioxide is increased to a maximum rate.
8. The method of claim 5 wherein the injection rate of the carbon dioxide during step (b) is 0.1 to 2 MSCF/day.

* * * * *

United States Patent [19]

Shu

[11] Patent Number: 4,474,237
[45] Date of Patent: Oct. 2, 1984

[54] METHOD FOR INITIATING AN OXYGEN DRIVEN IN-SITU COMBUSTION PROCESS

- [75] Inventor: Winston R. Shu, Dallas, Tex.
[73] Assignee: Mobil Oil Corporation, New York, N.Y.
[21] Appl. No.: 559,138
[22] Filed: Dec. 7, 1983
[51] Int. Cl.³ E21B 43/243; E21B 36/02
[52] U.S. Cl. 166/261; 166/59; 166/242
[58] Field of Search 166/260, 261, 272, 303, 166/59, 242

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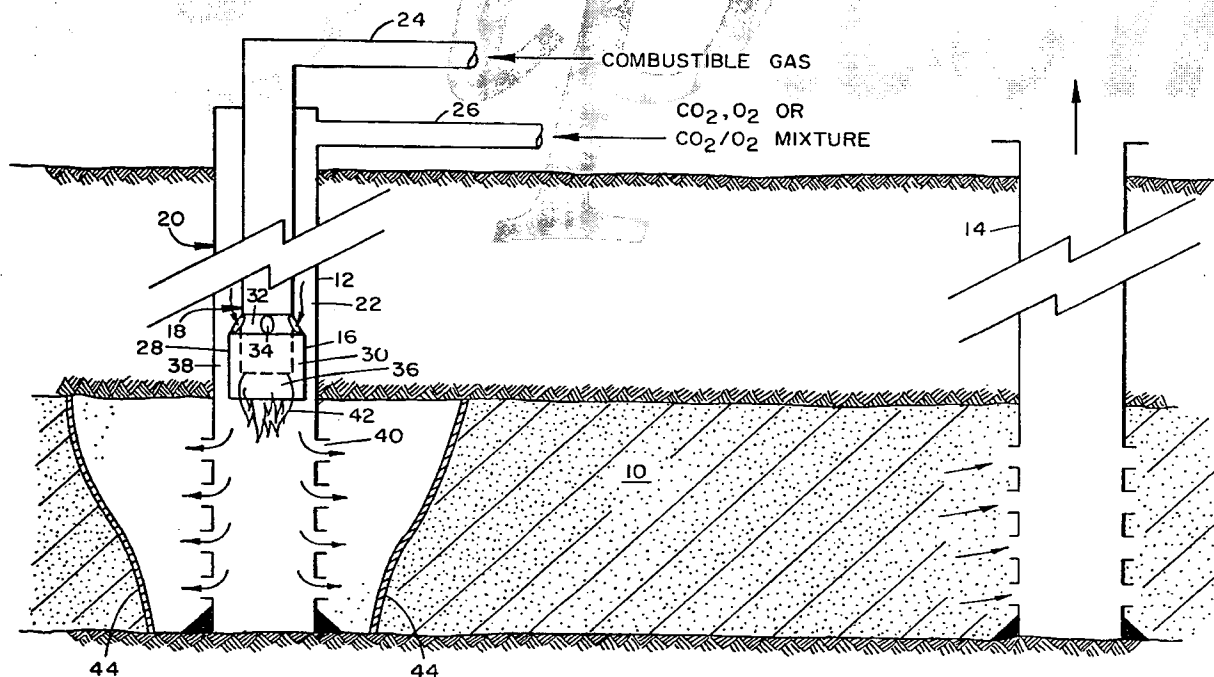
Primary Examiner—George A. Suchfield

Attorney, Agent, or Firm—Alexander J. McKillop;
Michael G. Gilman; Malcolm D. Keen

[57] ABSTRACT

A method for initiating an in-situ combustion process for the recovery of oil from a subterranean, viscous oil-containing formation wherein a combustible gas such as natural gas or methane and a mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide is injected into a downhole burner in the injection well and ignited to produce combustion gases containing heat energy that pass into the formation. After the area of the formation surrounding the injection well reaches a temperature within the range of 500° to 800° F., injection of the combustible gas is terminated and injection of the mixture of oxygen and carbon dioxide is continued to initiate in-situ combustion in the formation. Thereafter, essentially pure oxygen is injected into the formation to support in-situ combustion in the formation for the recovery of oil therefrom. Alternatively, after the combustion front has been formed, injection of the mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide is continued until the combustion front has moved at least 30 feet into the formation before essentially pure oxygen is injected.

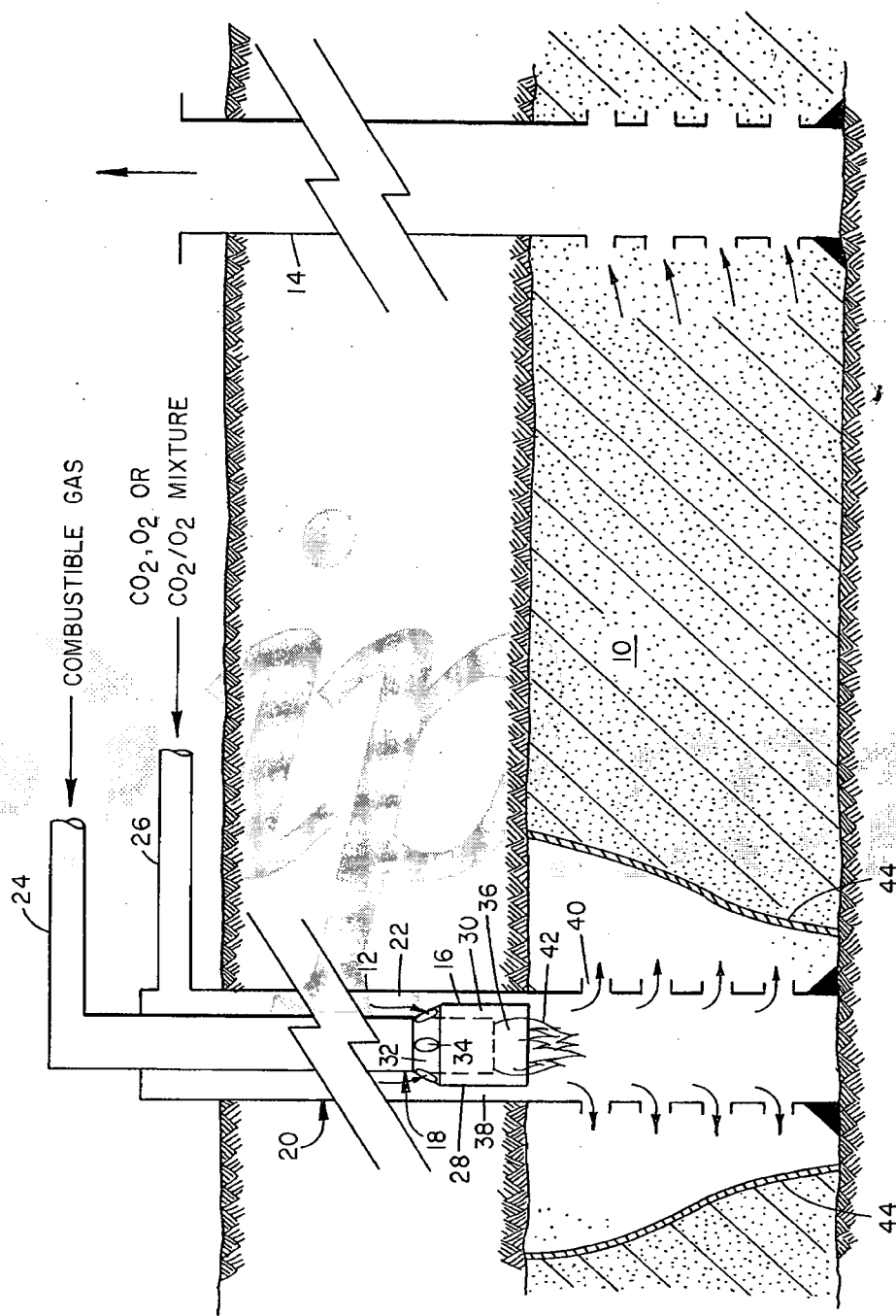
8 Claims, 1 Drawing Figure



U.S. Patent

Oct. 2, 1984

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METHOD FOR INITIATING AN OXYGEN DRIVEN IN-SITU COMBUSTION PROCESS

BACKGROUND OF THE INVENTION

This invention relates to a method for initiating an in-situ combustion process to recover energy raw materials such as petroleum hydrocarbons from a subterranean formation by the introduction of oxygen into the formation.

Since the invention of the in-situ combustion method for petroleum recovery by F. A. Howard in 1923, a number of methods have been developed, the object of which is the production of heat within the reservoir, especially of sufficient heat, by means of partial combustion of oil residues in a petroleum reservoir to enable recovery of the remaining oil. The most important mechanisms contributing to enhanced recovery are viscosity reduction by means of heat, distillation and cracking of the oil and of the higher boiling components, sweeping out of the oil with hot water and extraction of the oil by means of miscible products.

The use of high purity oxygen in place of air significantly improves the performance of the in-situ combustion process. One of the disadvantages of the use of oxygen is its hazardous nature that could lead to uncontrolled reactions or explosions. Because of the hazardous nature of pure oxygen in reacting with other materials much work has been done to reduce this danger. In addition to the question of reaction of oxygen with various materials, the dynamics of compressible fluids is also an important factor in determining what hazard exists when a material is reacted with oxygen.

It is known from experience in autogenous gas cutting that not only the nature of the material but also the composition of the gas used has an influence of the material's cutting quality. With an oxygen content of less than 95%, steel can still be ignited but combustion is not self-sustaining. These ratios apply to atmospheric pressure. In one series of tests, Hvizdos et al, (*Journal of Petroleum Technology*, June 1983, pp. 1061-1070), reported that samples of carbon steel with a geometry similar to the tubing used in injection wells were tested. The results of Hvizdos et al show that oxygen concentration and pressure have a dramatic effect on flame propagation. For instance, it was found that the tubing, once ignited, would not continue to burn if the oxygen concentration was below a critical level but that the flame would propagate if the oxygen concentration was over that level. The critical level of oxygen concentration is a function of pressure, illustrating that data at low pressure should not be used to plan projects which will operate at high pressure. For safety, a low limit of 45% oxygen should be used for a wide-range of pressures.

Great importance is accordingly attached to the structure of the spaces in which the oxygen is flowing. Should said spaces possess a large inner surface in relation to the volume, then the danger of an explosion when a fuel and oxygen are reacted is greatly reduced. Consequently the reaction of oxygen with oil contained in the pores of the reservoir rocks poses relatively few problems. However, given certain geometric proportions of the spaces through which the oxygen flows, local temperature peaks can occur and cause ignition of the material (steel, plastic, wood, etc.). It follows that the most dangerous point along the oxygen's flow path is the borehole. The operating conditions in a petroleum borehole are such that when high percentage oxygen is

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introduced there is a great danger of an explosion in the borehole. Neither is the borehole equipment made from deflagration-proof material (copper, Inconel) nor is the condition of the equipment, due to contact with corrosive, erosive and organic agents, such that the danger is lessened.

The injection of oxygen into a wellbore presents significant hazards and requires safety precautions. Previous work in this regard includes the injection of O₂ through a bottom water zone, as disclosed in U.S. Pat. No. 3,208,519 by T. V. Moore, and the initiation of combustion with air followed by oxygen as disclosed in U.S. Pat. No. 4,042,026 by G. Pusch et al. All these methods use air to establish gas flow. However, it has been found that injection of air increases the viscosity of the oil by 100 times when the oil is contacted by air for two days. This increase in viscosity is detrimental to the recovery process.

U.S. Pat. No. 1,410,042 to Shu discloses an in-situ combustion operation wherein a mixture of oxygen and carbon dioxide is injected into the formation to initiate combustion followed by injection of oxygen.

It is therefore the objective of this invention to eliminate these risks or at least reduce them to an acceptable level within the framework of conventional equipment used in boreholes for the recovery of energy raw materials such as petroleum hydrocarbons.

SUMMARY

The present invention relates to a method for initiating an in-situ combustion operation in a process for the recovery of oil from a subterranean, viscous oil-containing formation penetrated by an injection well and a spaced-apart production well comprising the steps of assembling a downhole burner in the injection well near the top of the formation, introducing a combustible gas such as methane or natural gas and a mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide into said downhole burner to produce a combustible mixture therein, igniting said combustible mixture to produce hot combustion gases containing heat energy that passes into the formation adjacent said injection well, continuing injection of said combustible gas and said mixture of oxygen and carbon dioxide until the temperature of the area of the formation surrounding the injection well is within the range of 500° to 800° F. Thereafter injection of the combustible gas is terminated and injection of the mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide into the formation via the injection well is continued to initiate in-situ combustion in the formation and form a combustion front therein. After formation of the combustion front or after the combustion front has advanced at least 30 feet into the formation, injection of the mixture of oxygen and carbon dioxide is terminated and thereafter essentially pure oxygen is injected into the formation via the injection well to support in-situ combustion.

BRIEF DESCRIPTION OF THE DRAWING

The accompanying drawing illustrates the method used in the invention for initiation of an in-situ combustion operation to recover oil from a subterranean formation.

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DESCRIPTION OF THE PREFERRED EMBODIMENT

Referring to the drawing, there is shown a subterranean, viscous oil-containing formation 10 such as a heavy oil or tar sand deposit penetrated by an injection well 12 and at least one spaced-apart production well 14. Injection well 12 and production well 14 are perforated or other fluid flow communication is established between the wells and a substantial portion of the vertical thickness of the formation 10. While recovery of the type contemplated by the present invention may be carried out by employing only two wells, it is to be understood that the invention is not limited to any particular number of wells. The invention may be practiced using a variety of well patterns as is well known in the art of oil recovery, such as an inverted five spot pattern in which an injection well is surrounded with four production wells, or in a line drive arrangement in which a series of aligned injection wells and a series of aligned production wells are utilized. Any number of wells which may be arranged according to any pattern may be applied in using the present method as illustrated in U.S. Pat. No. 3,927,716 to Burdyn et al, the disclosure of which is hereby incorporated by reference. Either naturally occurring or artificially induced fluid communication should exist between the injection well 12 and the production well 14. Fluid communication can be induced by injection of carbon dioxide, a solvent or steam. Fracturing may also be employed to improve the transmissibility of the formation using procedures well known in the art.

A gas fired burner, denoted generally by the reference numeral 16 is contained within injection well 12 and positioned just above the oil-containing formation 10. Referring to the drawing, the burner 16 which takes the general shape of an inverted Bunsen burner comprises tubing 18 disposed and centered within well casing 20 to form annular chamber 22 between said tubing and said casing, said tubing 18 being open at its downstream end. The upstream or upper end of tubing 18 located on the surface is in communication with conduit 24 connected to a source of a combustible gas such as natural gas or methane. Conduit 26 located on the surface is connected to a source of oxygen and carbon dioxide and is in communication with annular space 22. Said burner 16 comprises a flame tube 28 disposed concentrically around tubing 18 to form an annular chamber 30 around said tubing and between said tubing and said flame tube. Said flame tube 28 is open at its downstream end which extends beyond the downstream end of tubing 18 to a position near the upper portion of the formation 10. An annular connecting section 32 tapers in increasing cross-sectional area from a point above the lower end of tubing 18 to the upstream end of flame tube 28. A plurality of openings 34 are provided in the wall of said connecting section 32 for admitting a portion of the combustion-supporting gas from annular chamber 22 into annular chamber 30 and is then mixed with fuel emerging from the end of tubing 18 to form a combustible mixture in combustion zone 36. Flame tube 28 centered in well casing 20 forms an annular chamber 38 around said flame tube, and between said flame tube and said well casing. Both the well casing 20, tubing 18 and flame tube 28 of the injection well 12 are made of carbon steel commonly used in oil fields.

If it is determined that the formation 10 does not possess naturally occurring permeability to fluids, car-

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bon dioxide is injected into the formation via conduit 26, annulus 22, and through perforations 40 of injection well 12 for a period of time sufficient to establish fluid communication between the injection well 12 and the production well 14.

Thereafter, a combustible gas such as methane or natural gas is supplied to combustion zone 36 via conduit 24 and tubing 18. A mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide is passed via conduit 26 down through annular chamber 22. A portion of the mixture of oxygen and carbon dioxide in annulus 22 passes into combustion zone 36 via openings 34 and annulus 30 to form a combustible mixture with the gas emerging from the end of tubing 18. A small amount of a pyrophoric material is lowered down tubing 18 to ignite the combustible mixture in combustion zone 36 and produce hot combustion gases 42 containing heat energy. A thermocouple (not shown) is positioned in burner 16 for detecting ignition of the combustible mixture. That portion of the oxygen and carbon dioxide that does not pass through openings 34 from annulus 22 passes through annulus 38 and mixes with combustion gases emerging from the end of flame tube 28 thereby becoming hot. The hot combustion gases and heated excess mixture of oxygen and carbon dioxide from annulus 38 pass into the formation 10 via perforations 40 to heat the formation, and combustion in burner 16 is continued until the temperature of the area of the formation surrounding the injection well 12 is within the range of 500° to 800° F. Thereafter injection of the combustion gas is terminated and injection of the mixture of oxygen and carbon dioxide containing 55 to 80 volume percentage carbon dioxide is continued to spontaneously initiate in-situ combustion in the formation 10 and form a combustion front 44. The use of a gaseous mixture containing not more than 80 volume percent carbon dioxide does not interfere with initiation of in-situ combustion while using not less than 55 volume percent carbon dioxide (or no more than 45 volume percent oxygen) prevents flame propagation in the case of a downhole tubing fire.

Once the combustion front 44 is formed in the formation 10, or after sufficient oxygen and carbon dioxide have been injected to advance the combustion front away from the injection well 12 a predetermined distance, preferably at least 30 feet, injection of the mixture of O₂/CO₂ is terminated and thereafter essentially pure oxygen is injected into the formation via the injection well to support combustion, and fluids including oil are recovered from the formation via the production well 14. In another embodiment, after in-situ combustion has been initiated or after the combustion front has advanced away from the injection well a distance of at least 30 feet, the oxygen concentration of the injected O₂/CO₂ mixture is gradually increased at a controlled rate until the gas being injected is essentially pure oxygen. Advancing the combustion front 44 away from the injection well 12 before injecting essentially pure oxygen into the formation 10 ensures that there is no hydrocarbon residue near the injection well to come into contact with a gas containing more than 45 volume percent oxygen that could cause a downhole fire or explosion.

The use of a mixture of oxygen and carbon dioxide as the combustion-supporting gas to initiate in-situ combustion does not promote degradation in oil viscosity due to oxidation as is the case with mixture of oxygen and nitrogen as disclosed in prior arts. In the present

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process, any increase in oil viscosity due to oxidation is more than offset by a reduction in viscosity due to carbon dioxide dissolution. For example, an Athabasca bitumen with a viscosity of 50,000 cp at 104° F. will have a reduction in viscosity by 1000 times, when saturated with carbon dioxide at 600 psia (see Jacobs, F.A., et al, *J. Can. Pet. Tech.*, Oct.-Dec., 1980, pp. 46-50). In the latter example, it is disclosed that it requires only 200 scf of carbon dioxide to saturate a barrel of oil at 600 psia. Assuming the oil saturation is 100 bbls/ac-ft, it requires only 0.2×10^6 scf/ac-ft of carbon dioxide to saturate the oil. After in-situ combustion has been initiated, there is a sufficient amount of carbon dioxide generated in-situ to saturate the oil in the formation so there is no need to continuously inject carbon dioxide during the combustion process. It is noted that the dissolution of the carbon dioxide in the oil reduces the free gas in the reservoir and increases effective oil permeability. In addition, carbon dioxide has a nice fire-extinguishing characteristic which can be conveniently applied in the case of an accidental wellbore ignition.

The oxygen and carbon dioxide may both be stored in liquid form near the injection well or wells. Both materials may be more conveniently pumped in liquid form from separate storage tanks into a vaporizer and then injected into the injection well. The composition of the oxygen/carbon dioxide mixture supplied to the injection well is controlled by sensing and controlling the flow rates of the individual oxygen and carbon dioxide streams by means of a flow controller.

What is claimed is:

1. A method for initiating an in-situ combustion operation in a process for the recovery of oil from a subterranean, viscous oil-containing formation penetrated by an injection well and a spaced-apart production well comprising the steps of:

- (a) assembling a downhole burner having a combustion section in the injection well located near the formation;
- (b) introducing a combustible gas and a mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide into the combustion section of said downhole burner to produce a combustible mixture therein;

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(c) igniting said combustible mixture to produce hot combustion gases containing heat energy that passes into the formation adjacent said injection well;

(d) continuing injection of said combustible gas and mixture of oxygen and carbon dioxide until the temperature of the area of the formation surrounding the injection well is within the range of 500° to 800° F.;

(e) thereafter terminating the injection of the combustible gas and continuing to inject the mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide into the formation via the injection well to initiate in-situ combustion in the formation and form a combustion front; and
(f) terminating injection of the mixture of oxygen and carbon dioxide and thereafter injecting essentially pure oxygen into the formation via the injection to support in-situ combustion in the formation.

2. The method of claim 1 wherein said combustible gas is natural gas.

3. The method of claim 1 wherein said combustible gas is methane.

4. The method of claim 1 further including the step of continuing injection of said mixture of oxygen and carbon dioxide during step (e) until the combustion front has moved a predetermined distance into said formation.

5. The method of claim 4 wherein the combustion front has moved a distance of at least 30 feet into the formation from the injection well.

6. The method of claim 1 further including increasing the oxygen concentration of the injected mixture of oxygen and carbon dioxide following step (e) until the injected gas comprises essentially pure oxygen.

7. The method of claim 1 wherein said downhole burner is formed from an elongated vertical combustion chamber means open at both ends, having both combustible gas supply and oxygen/carbon dioxide mixture supply conduits connected thereto for mixing the combustible gas and mixture of oxygen and carbon dioxide in the combustion chamber.

8. The method of claim 1 wherein the tubing and casing of the injection well comprises carbon steel.

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US005626191A

United States Patent [19]

Greaves et al.

[11] **Patent Number:** 5,626,191[45] **Date of Patent:** May 6, 1997[54] **OILFIELD IN-SITU COMBUSTION PROCESS**

[75] Inventors: **Malcolm Greaves**, Avon, United Kingdom; **Alexandru T. Turta**, Calgary, Canada

[73] Assignee: **Petroleum Recovery Institute**, Calgary, Canada

[21] Appl. No.: 494,300

[22] Filed: Jun. 23, 1995

[51] Int. Cl.⁶ E21B 43/24; E21B 43/243; E21B 43/30

[52] U.S. Cl. 166/245; 166/50; 166/261; 166/263

[58] Field of Search 166/50, 245, 256, 166/261, 263, 272

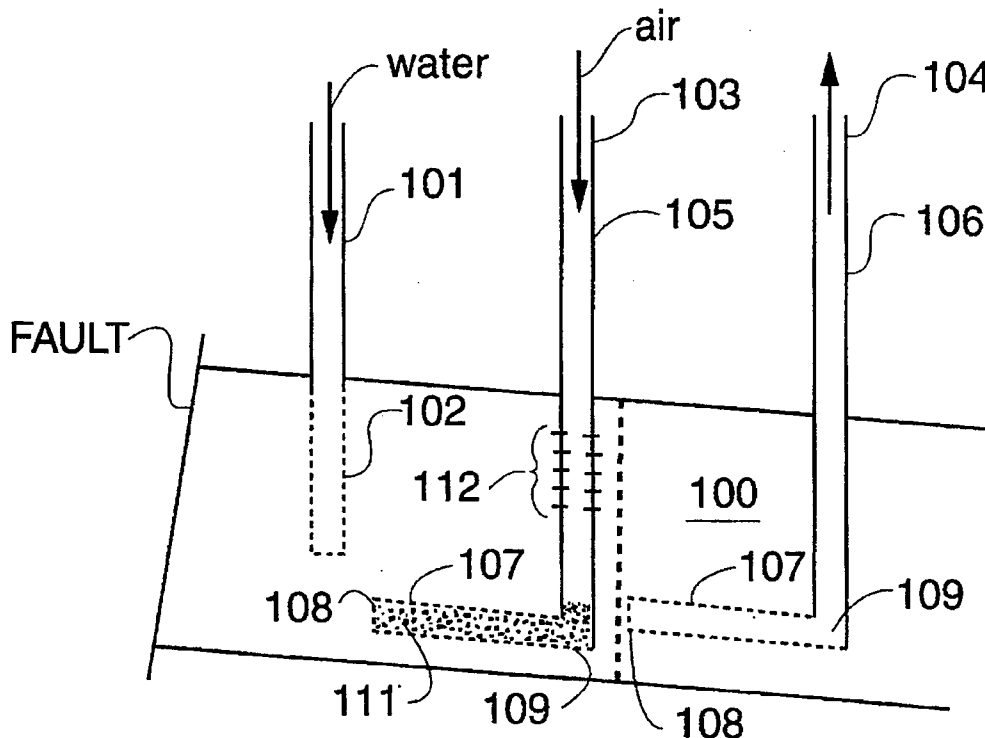
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Primary Examiner—George A. Suchfield*Attorney, Agent, or Firm*—Sheridan Ross P.C.[57] **ABSTRACT**

A well arrangement is used wherein the production wells are generally horizontal, positioned low in the reservoir and arranged generally perpendicularly to a laterally extending combustion front. The combustion front is propagated by a row of vertical air injection wells completed high in the reservoir. The open production wells function to cause the combustion front to advance along their lengths. The process is characterized by a generally upright combustion front having good vertical and lateral sweep.

7 Claims, 14 Drawing Sheets

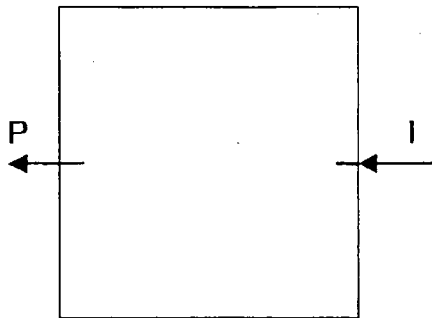


FIG. 1A.

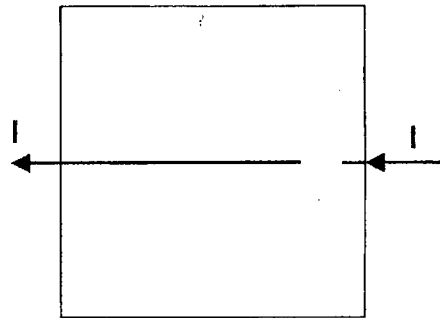


FIG. 2A.

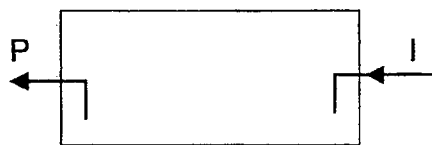


FIG. 1B.

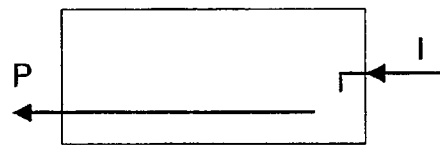


FIG. 2B.

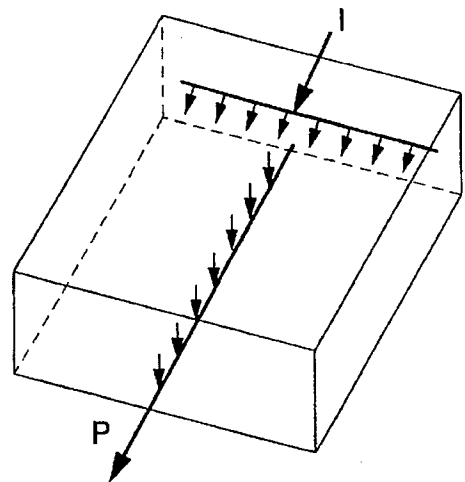


FIG. 3.

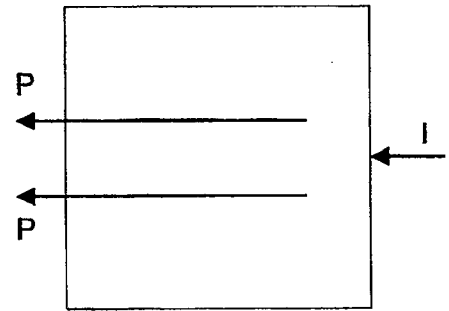


FIG. 4A.

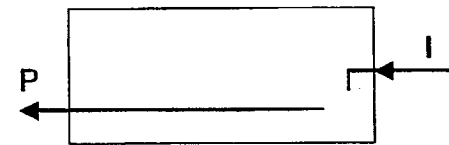


FIG. 4B.

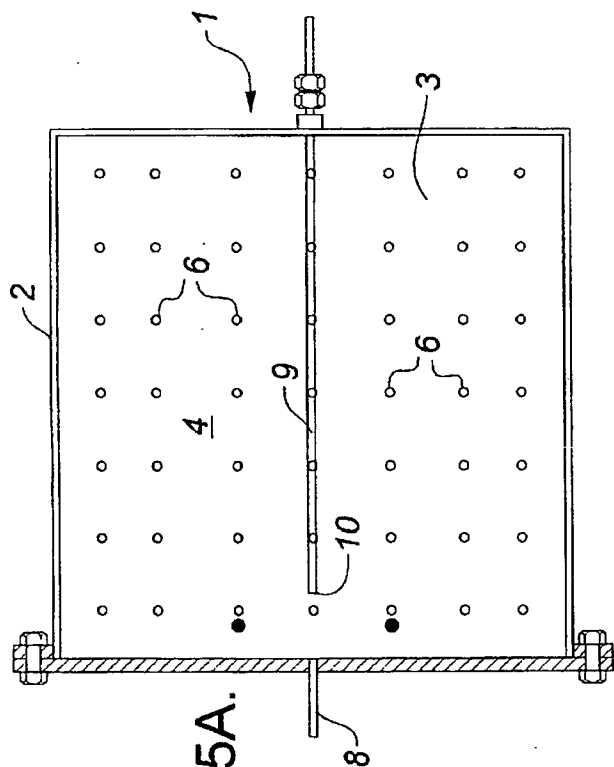


FIG. 5A.

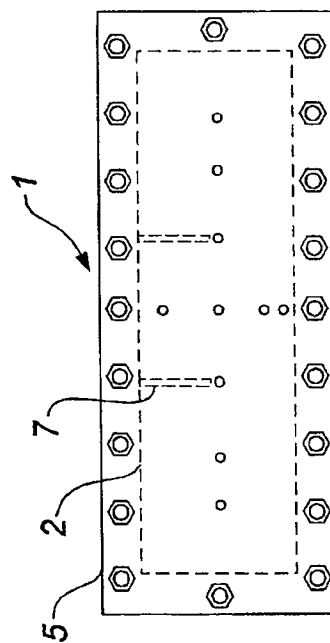


FIG. 5C.

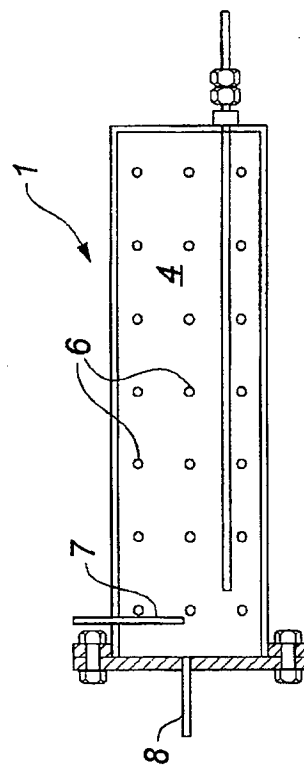


FIG. 5B.

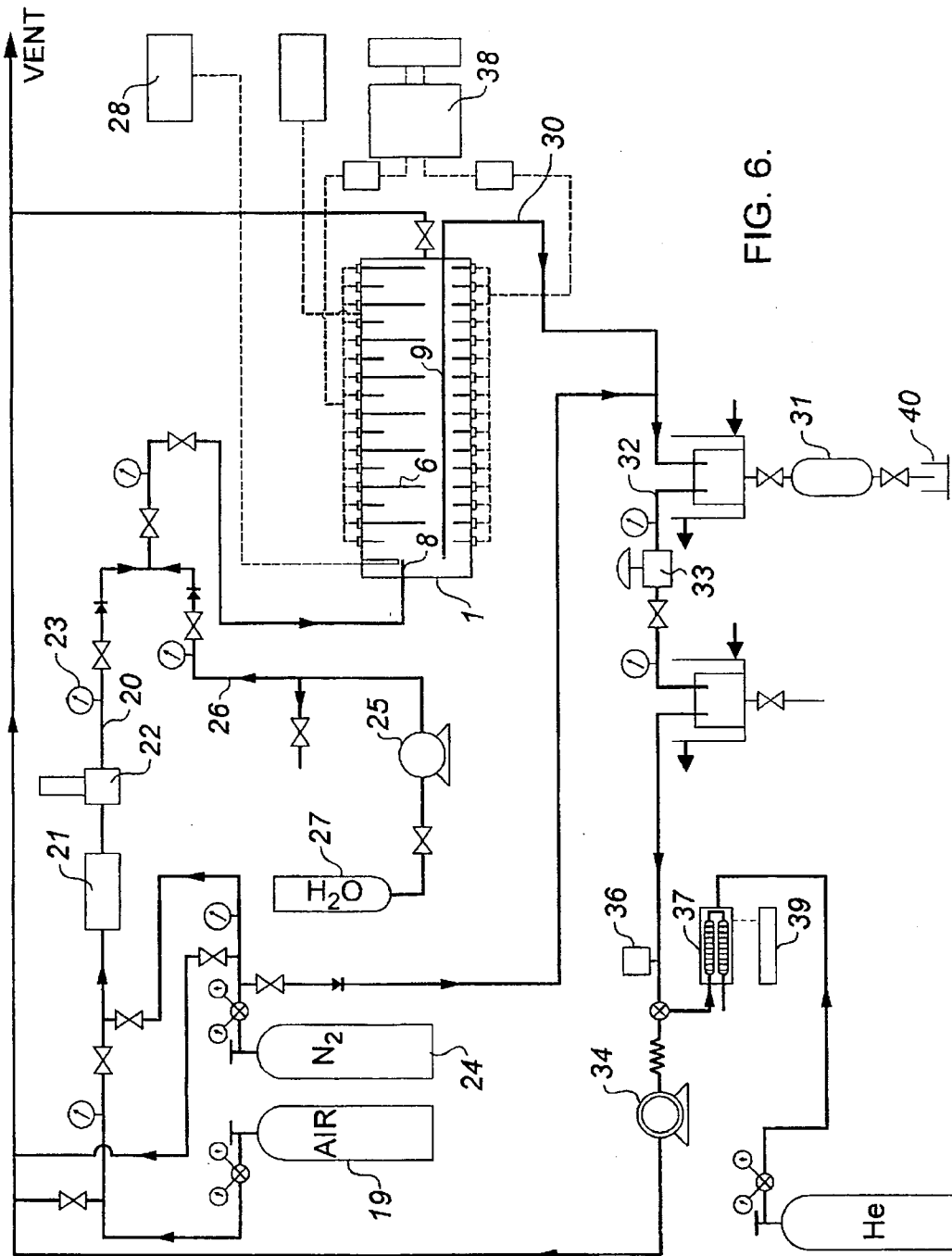


FIG. 6.

Fig. 7A (PRIOR ART)

VOLUME SWEEPED BY THE COMBUSTION FRONT
ALONG THE HORIZONTAL MIDPLANE (Time = 930 min.)

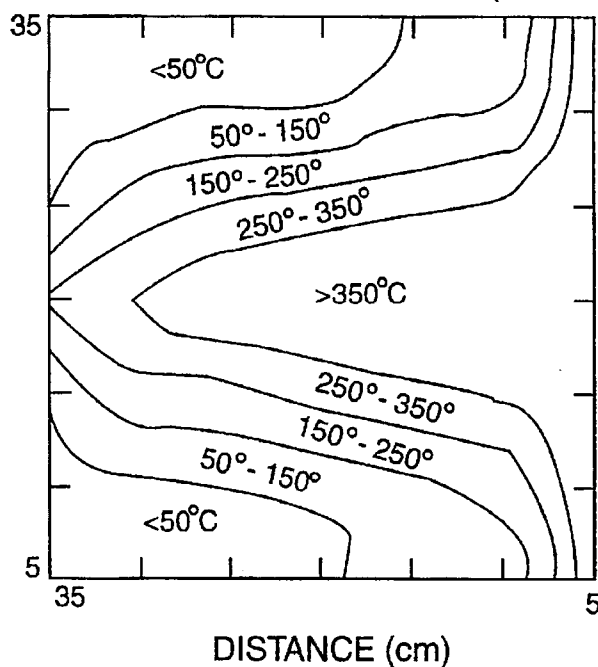


Fig. 7B (PRIOR ART)

VOLUME SWEEPED BY THE COMBUSTION FRONT
ALONG THE VERTICAL MIDPLANE (Time = 930 min.)

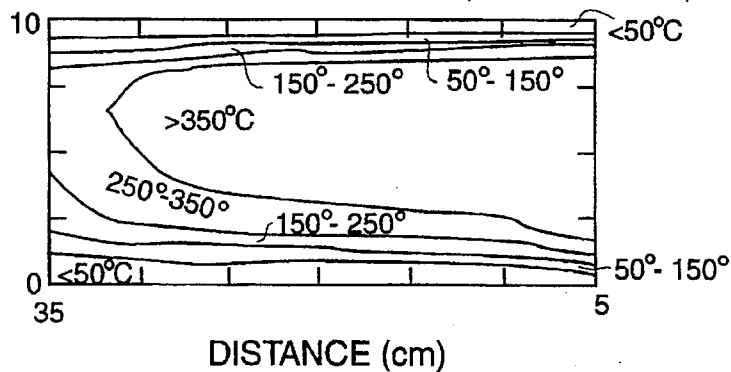
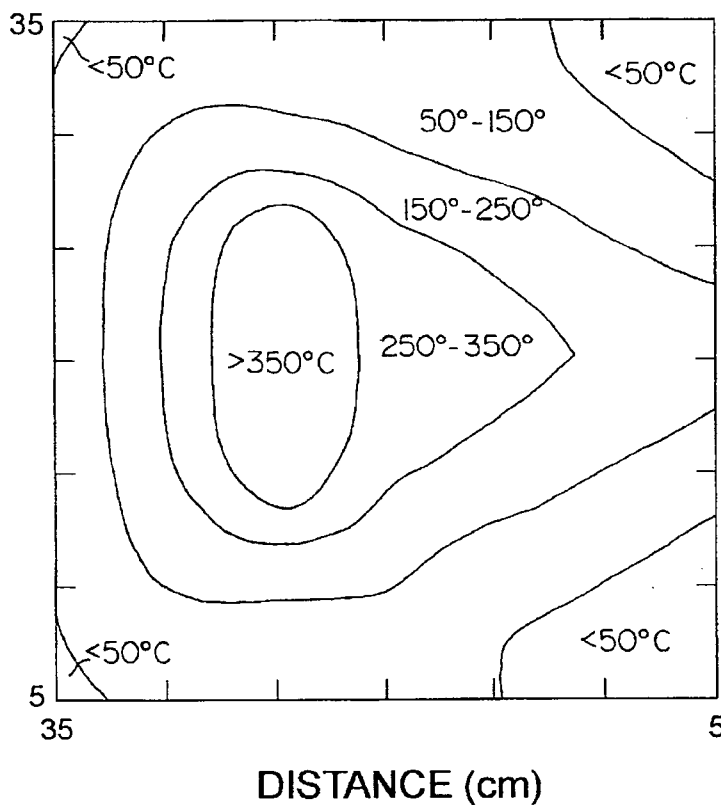


FIG. 8A.

VOLUME SWEEPED BY THE COMBUSTION FRONT
ALONG THE HORIZONTAL MIDPLANE (Time = 999 min.)

**FIG. 8B.**

VOLUME SWEEPED BY THE COMBUSTION FRONT
ALONG THE VERTICAL MIDPLANE (Time = 999 min.)

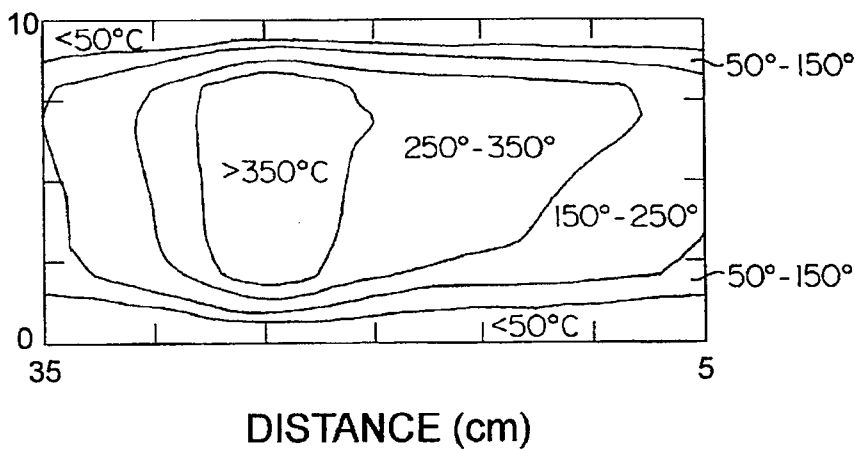


FIG. 9A.

HORIZONTAL TEMPERATURE PROFILES AT
TOP LAYER 45 MINUTES AFTER IGNITION

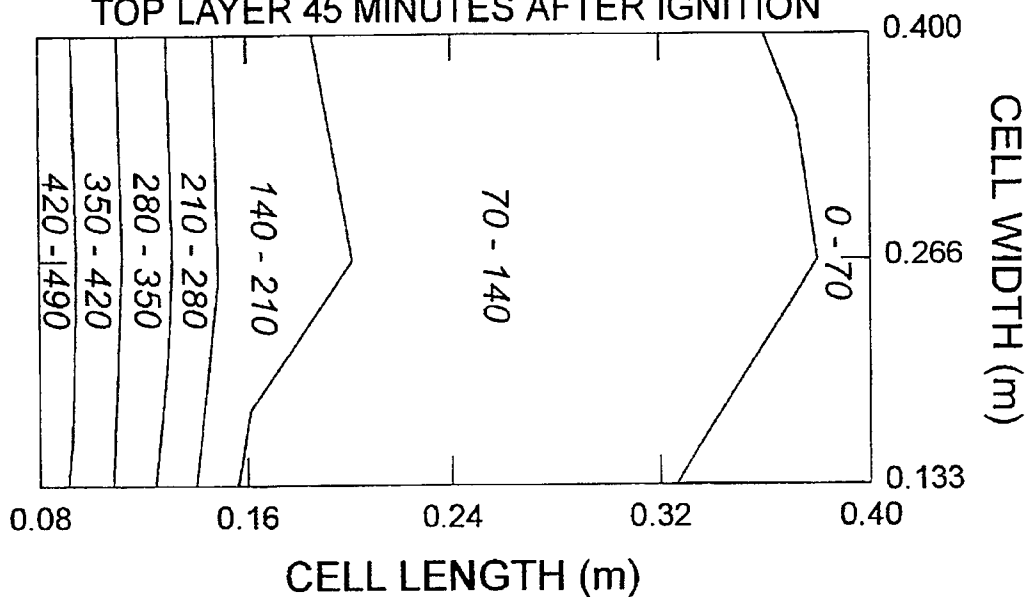


FIG. 9B.

HORIZONTAL TEMPERATURE PROFILES AT
BOTTOM LAYER 45 MINUTES AFTER IGNITION

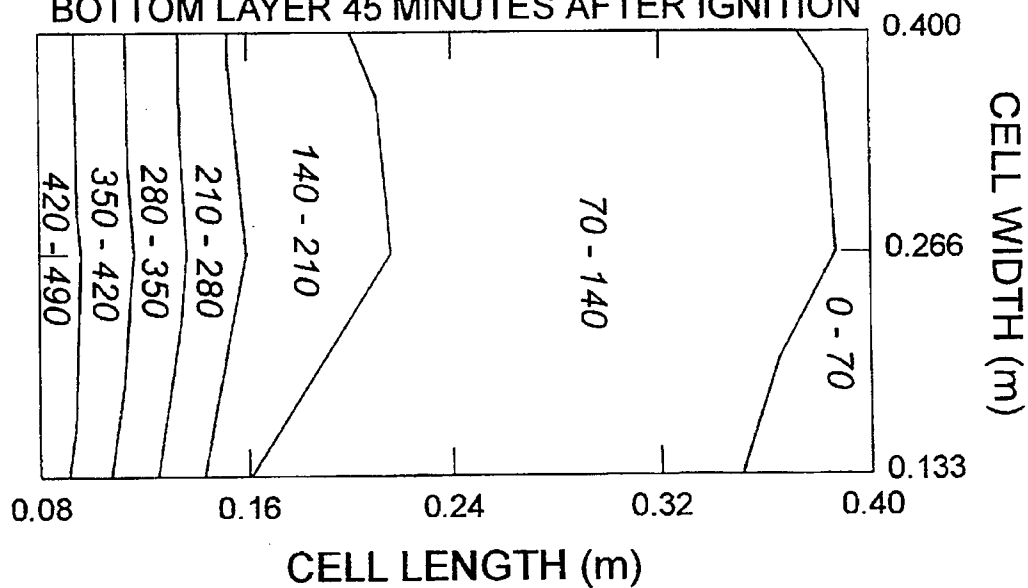


FIG. 9C.

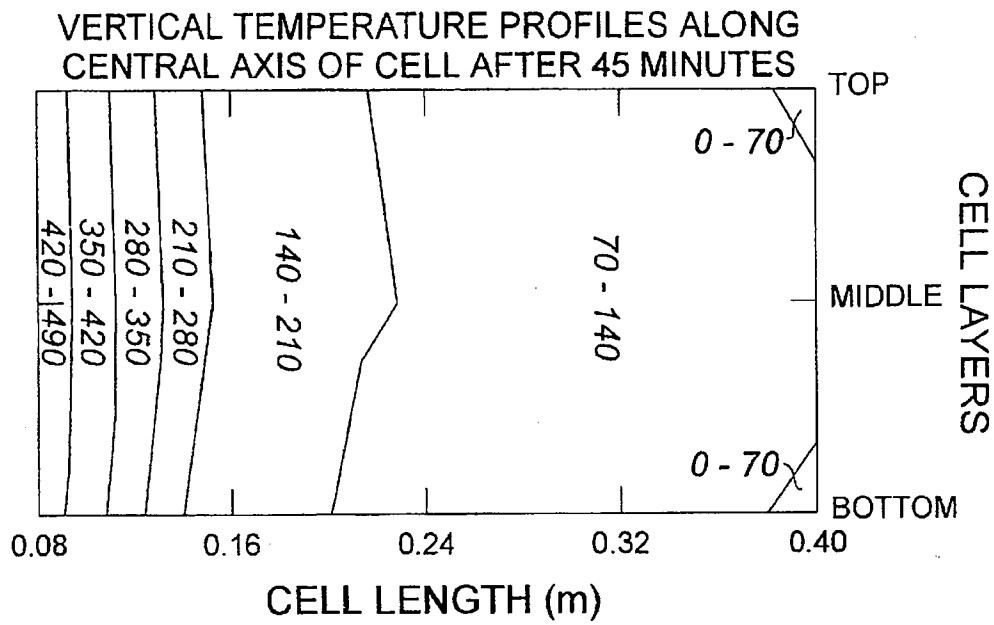


FIG. 9D.

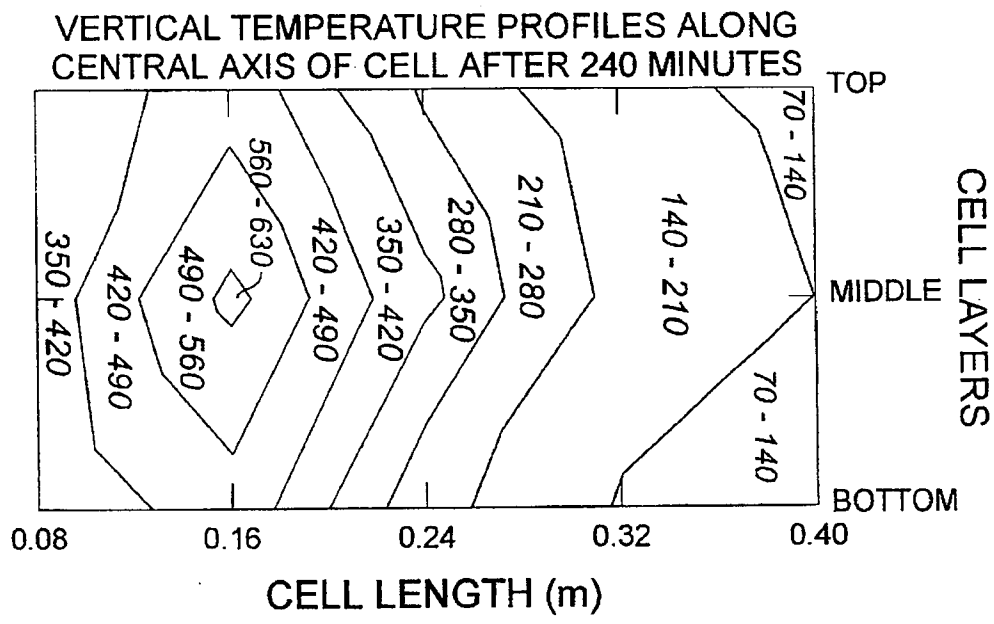


FIG. 9E.

VERTICAL TEMPERATURE PROFILES ALONG
CENTRAL AXIS OF CELL AFTER 360 MINUTES

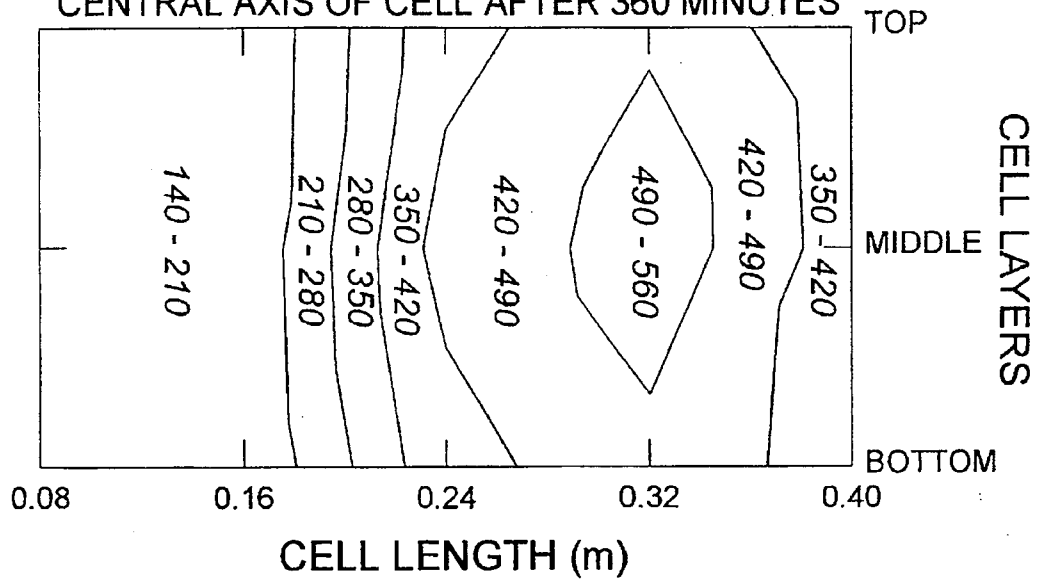


FIG. 9F.

VERTICAL TEMPERATURE PROFILES ALONG
CENTRAL AXIS OF CELL AFTER 460 MINUTES

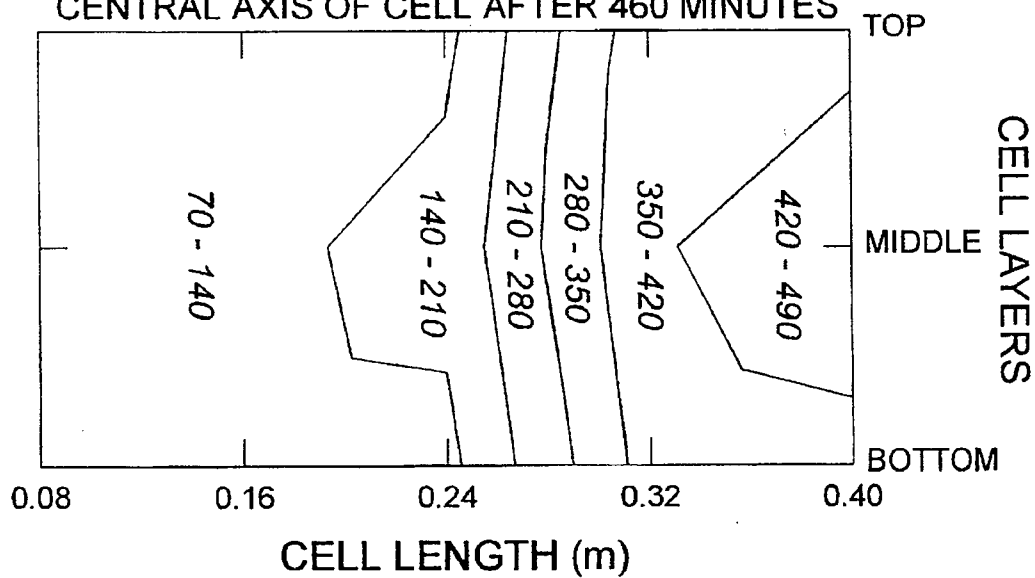


FIG. 10.

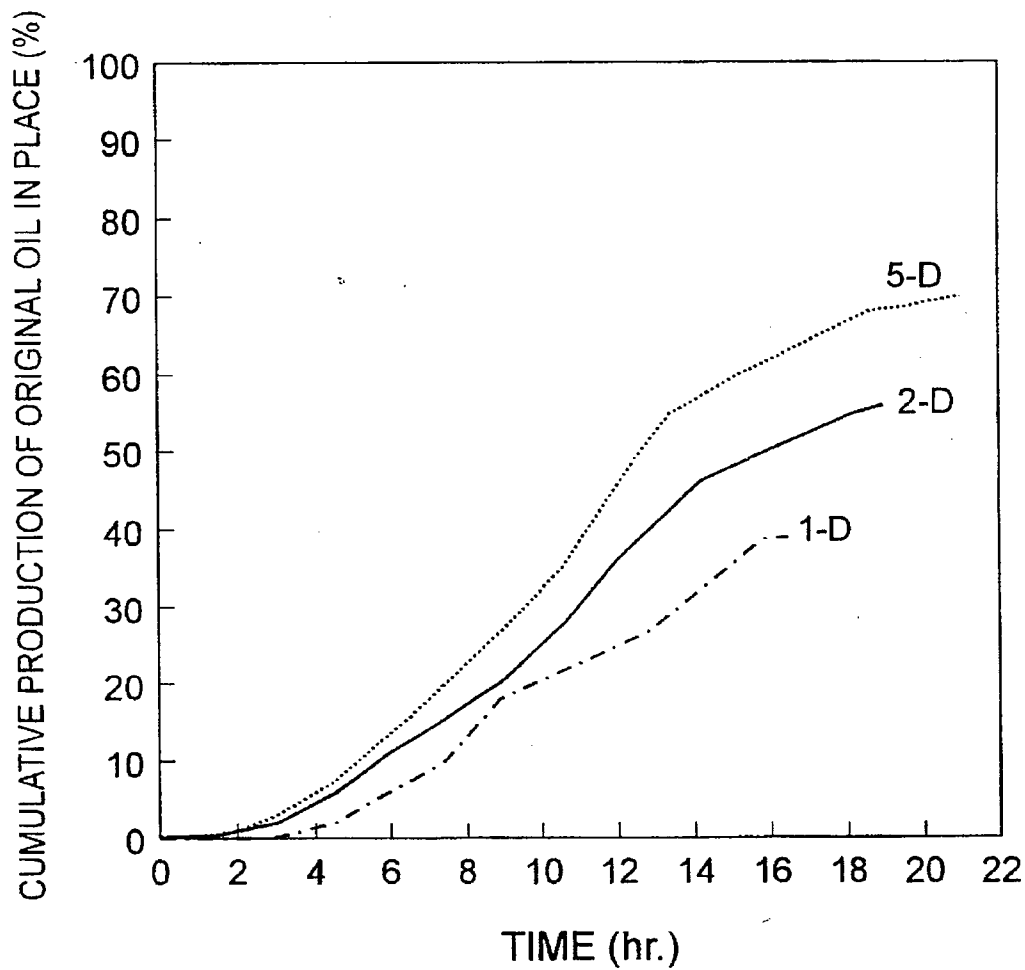


FIG. 11.

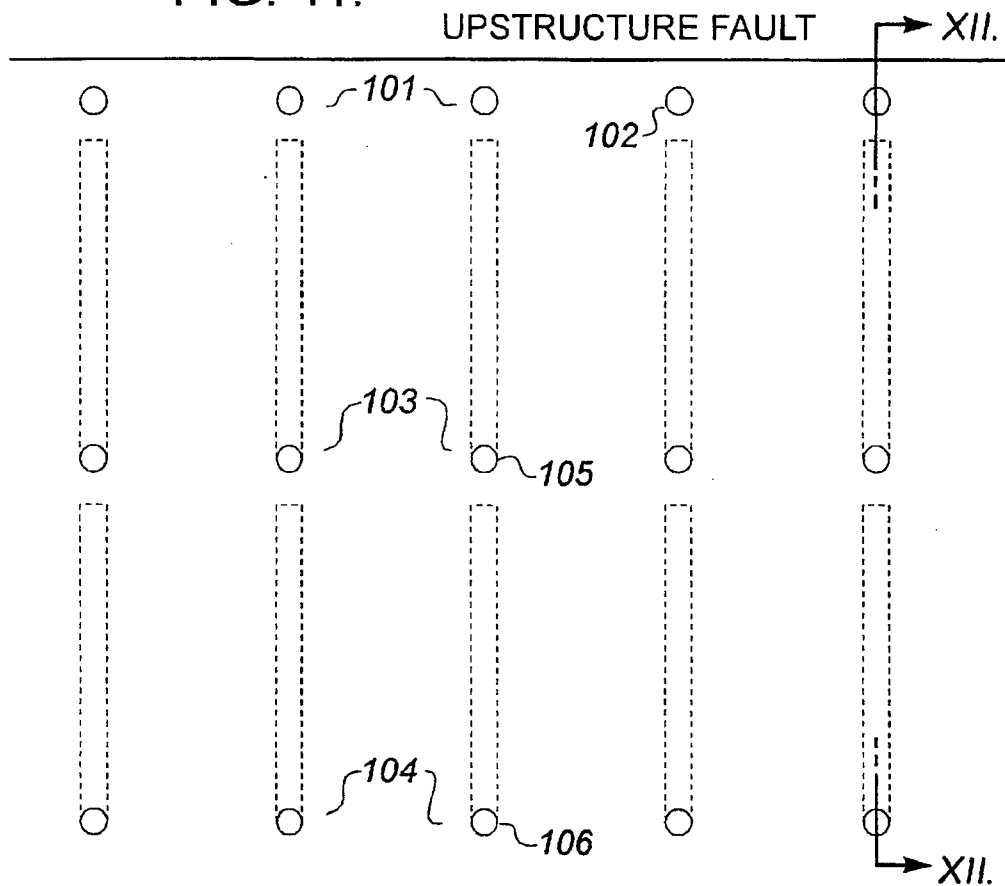


FIG. 12.

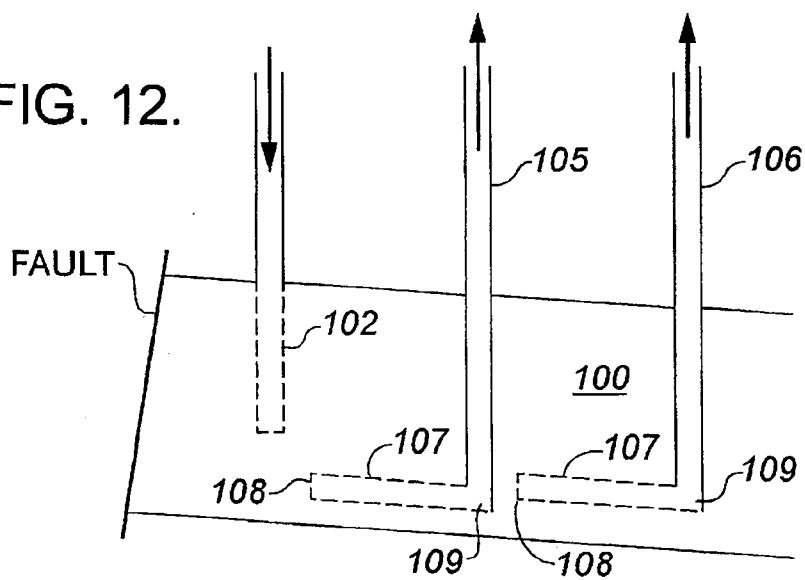


Fig. 13

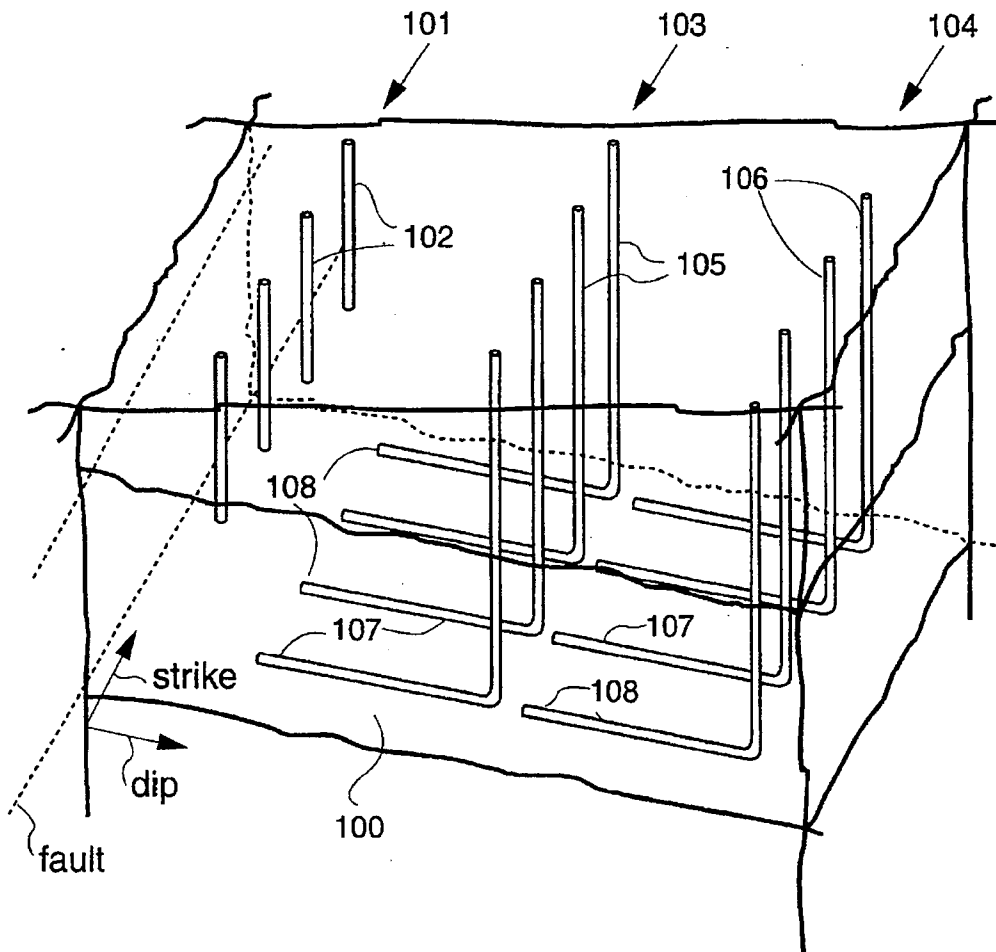


Fig 14A

UPSTRUCTURE FAULT

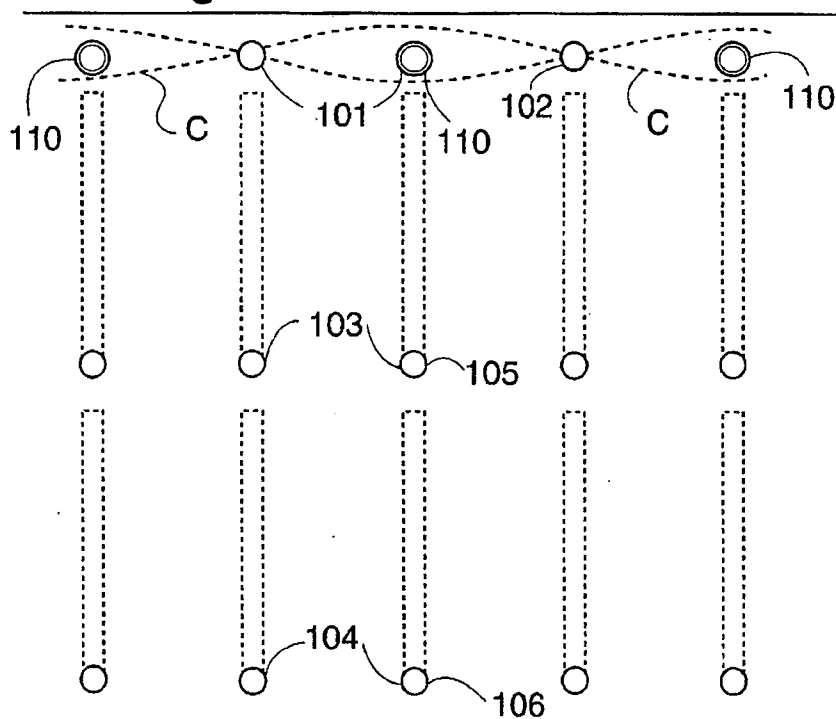
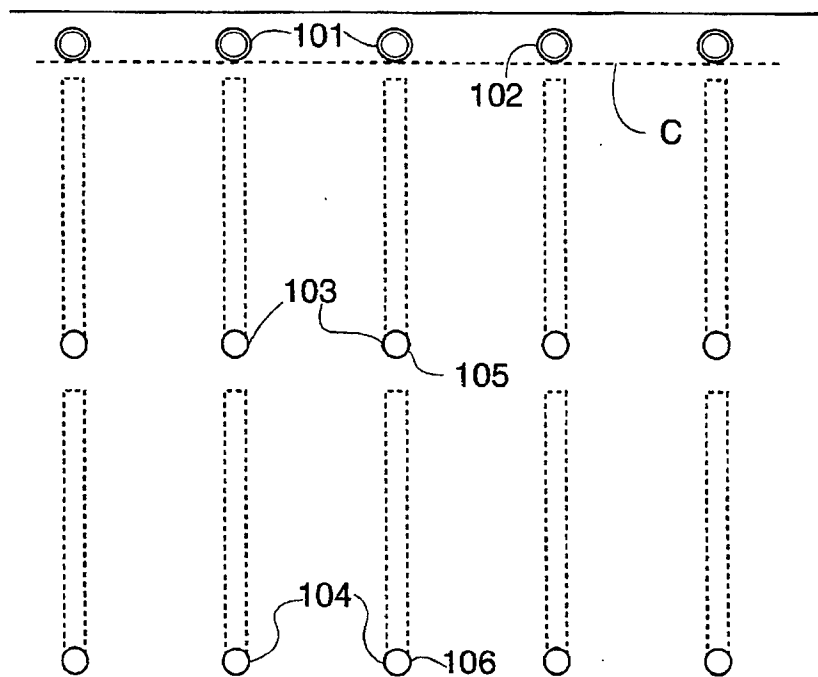
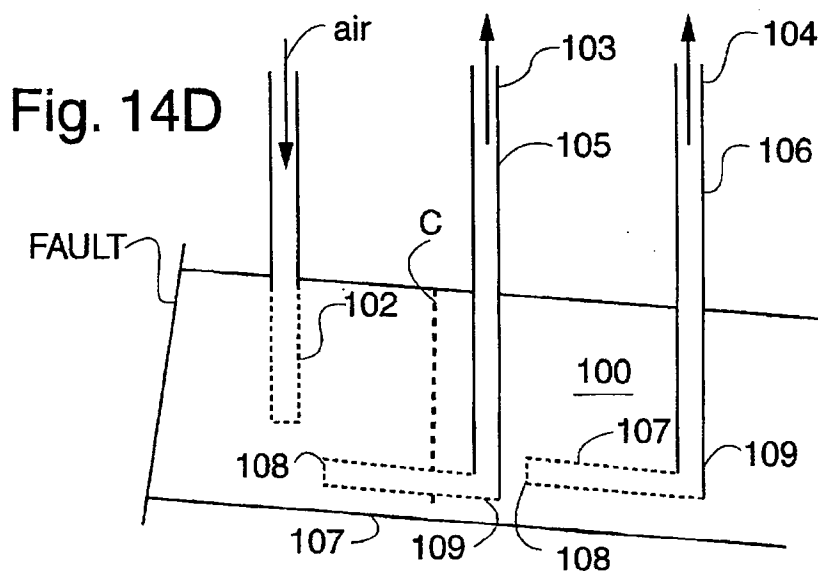
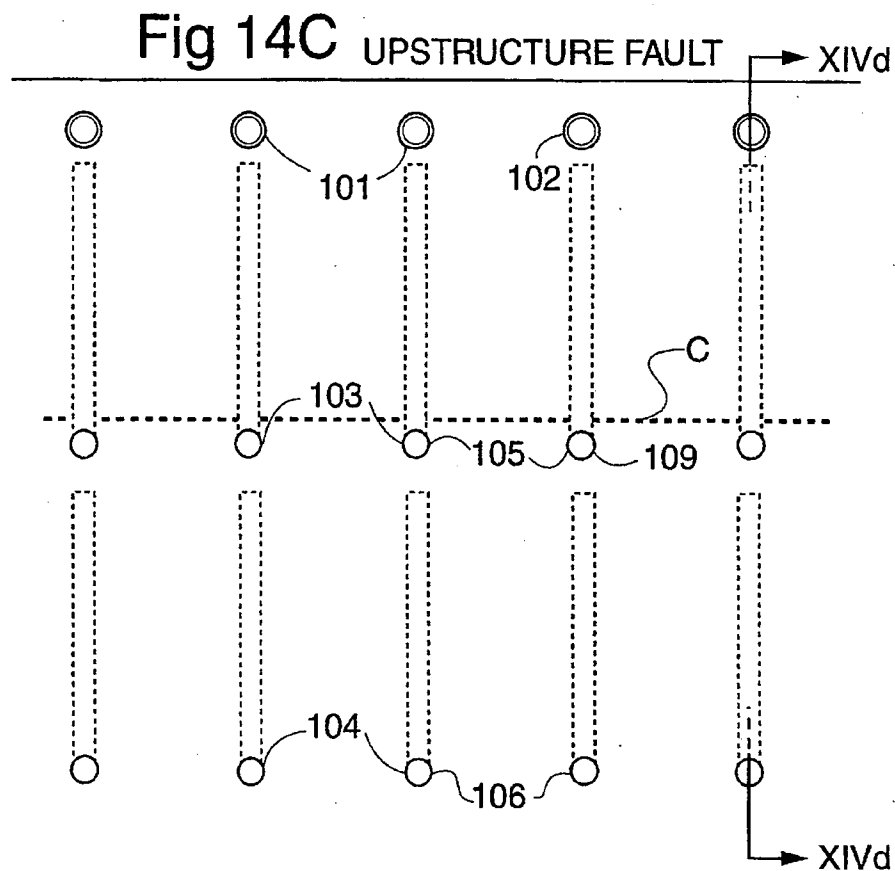
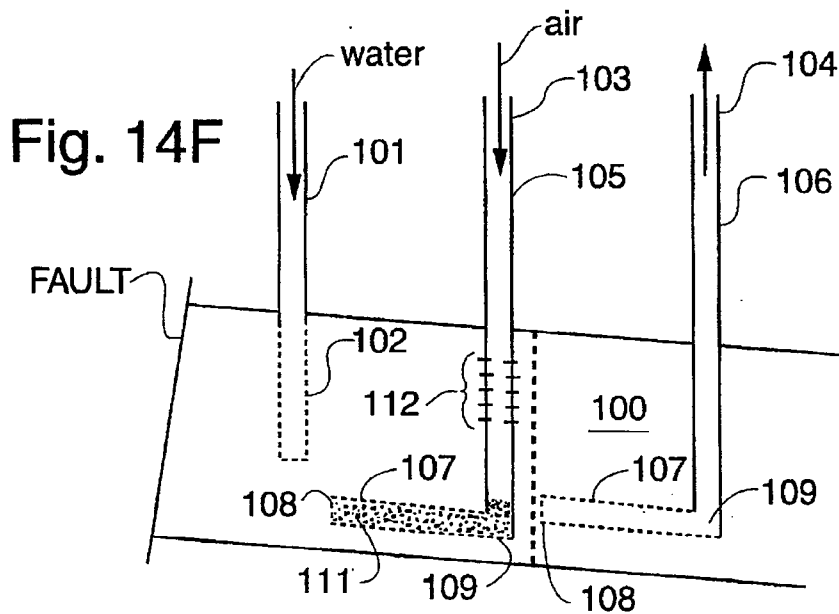
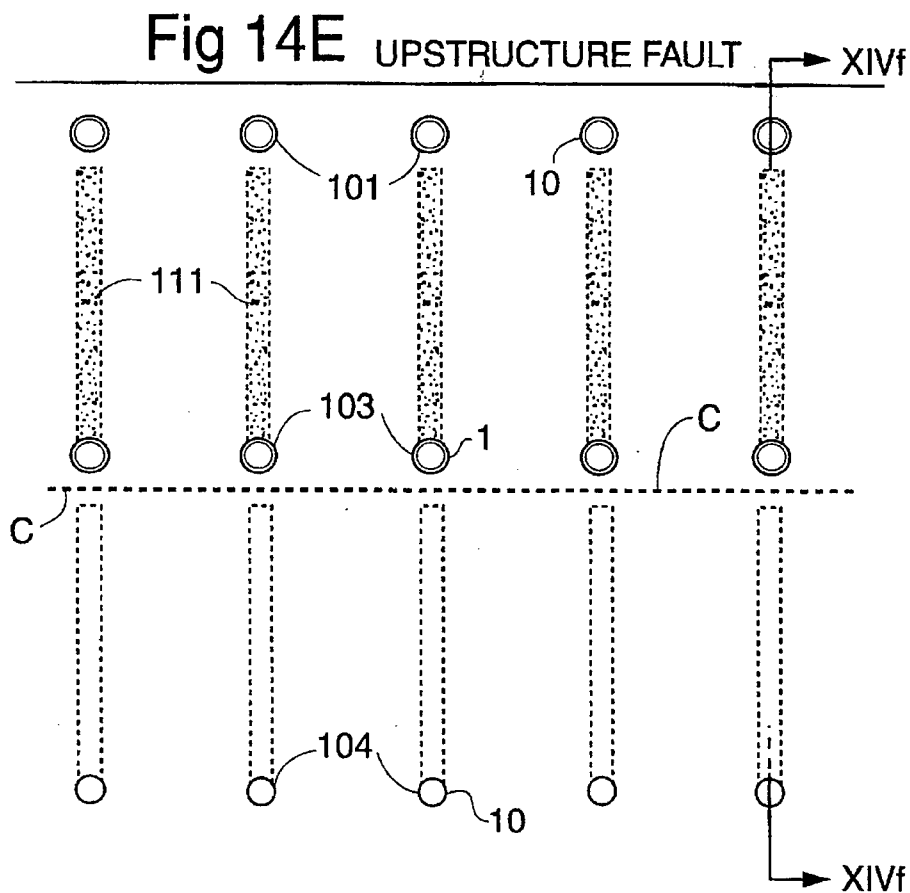


Fig. 14B

UPSTRUCTURE FAULT







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OILFIELD IN-SITU COMBUSTION PROCESS

TECHNICAL FIELD

This invention relates to an in-situ combustion process for recovering hydrocarbons from an underground reservoir. More particularly, it relates to a process in which the production wells each have a horizontal leg and these legs are positioned perpendicularly to and in the path of a laterally extending and advancing combustion front.

BACKGROUND ART

In-situ combustion processes are applied for the purpose of heating heavy oil, to mobilize it and drive it to an open production well for recovery.

In general, the usual technique used involves providing spaced apart vertical injection and production wells completed in a reservoir. Typically, an injection well will be located within a pattern of surrounding production wells. Air is injected into the formation, the mixture of air and hydrocarbons is ignited, a combustion front is generated in the formation and this resulting combustion front is advanced outwardly toward the production wells. Or alternatively, a row of injection wells may feed air to a laterally extending combustion front which advances as a line drive toward a parallel row of production wells.

In both cases, the operator seeks to establish an upright combustion front which provides good vertical sweep and advances generally horizontally through the reservoir with good lateral sweep.

However, the processes are not easy to operate and are characterized by various difficulties.

One such difficulty arises from what is referred to as gravity segregation. The hot combustion gases tend to rise into the upper reaches of the reservoir. Being highly mobile, they tend to penetrate permeable streaks and rapidly advance preferentially through them. As a result, they fail to uniformly carry out, over the cross-section of the reservoir, the functions of heating and driving oil toward the production wells. The resulting process volumetric sweep efficiency is therefore often undesirably low. Typically the efficiencies are less than 30%.

It would therefore be desirable to modify the in-situ combustion technique so as to better control the way in which the combustion gases flow and the front advances, so as to increase the volumetric sweep efficiency. The work underlying the present invention was undertaken to reach this objective.

The invention, in its preferred form, incorporates aspects of two processes which are known in the art.

Firstly, it is known to initiate the combustion drive at the high end of a reservoir having dip and propagate the combustion front downstructure, isobath-wise. This procedure to some extent reduces the problem of gravity segregation of the combustion gases, because the gases are forced to displace the oil downward, in a gravity influenced, stable manner.

Secondly, Ostapovich et al, in U.S. Pat. No. 5,211,230, disclose completing a vertical air injection well relatively high in the reservoir and a horizontal production well relatively low in the reservoir. The production well is positioned transversely relative to the combustion front emanating from the injection well. The production well is spaced from the injection well. By implementing this arrangement, the combustion front follows a downward path, toward the low pressure sink provided by the produc-

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tion well and the benefit of gravity drainage of heated oil is obtained. These effects enhance the sweep efficiency of the process and facilitate the heated oil reaching the production well. However, the premature breakthrough of the combustion front at a locus along the length of the transverse, horizontal leg will result in leaving an unswept reservoir zone between the leg's toe and the breakthrough locus.

The present invention will now be described.

SUMMARY OF THE INVENTION

In accordance with the preferred form of the invention, it has been determined that:

if a generally linear and laterally extending, upright combustion front is established and propagated high in an oil-containing reservoir; and

if an open production well is provided having a horizontal leg positioned low in the reservoir so that the well extends generally perpendicularly to and lies in the path of the front and has its furthest extremity ("toe") spaced from but adjacent to the injection source; then

the production well provides a low pressure sink and outlet that functions to induce the front to advance in a guided and controlled fashion, first towards the toe and then along the length of the horizontal leg—under these circumstances, the front has been found to remain generally stable and upright and is characterized by a relatively high sweep efficiency;

additionally, the air flows through the burnt out reservoir and through the upright combustion front, forming combustion gases (CO_2 , CO , H_2O) whose streamlines bend towards the horizontal leg, due to the downward flow gradient created by the action of the production well as a sink. An oil upgrading zone is formed immediately ahead of the front. The draining oil tends to keep the bore of the horizontal leg full, so there is little opportunity for unused oxygen to be produced through the production well until the front has advanced the length of the leg; and

as just stated, the heated oil drains readily into the production well for production therethrough.

When compared in experimental runs with a conventional procedure wherein spaced apart, simulated vertical air injection and production wells were completed in the same horizontal plane of the reservoir and a combustion front was initiated and propagated, the present invention was found to be relatively characterized by:

increased percentage of reservoir volume swept, increased recovery percentage of the oil in place, and increased average gravity of produced oil.

Additionally, the present procedure involving a horizontal producer, is found to be characterized by the advantage that the combustion front always intercepts the horizontal leg of the horizontal well at the toe point, rather than at a location along the length of the leg.

Up to this point, the invention has been described with reference only to a combustion process. As previously stated, an important feature of the invention is that the properly oriented, open horizontal leg of the production well functions to directionally guide and stabilize the advancing displacement front. There is a likelihood that this feature could beneficially be used with a steam, partially miscible gas drive or miscible solvent gas drive to control and stabilize the advancing displacement front which is functioning to reduce the viscosity of the oil directly in front of it.

Therefore, in broad terms, the invention is a process for reducing the viscosity of oil in an underground reservoir and driving it to a production well for recovery, comprising: providing a well, completed relatively high in the reservoir, for injecting a gaseous fluid into the reservoir to form an advancing, laterally extending displacement front operative to reduce the viscosity of reservoir oil; providing at least one open production well having a horizontal leg completed relatively low in the reservoir and positioned substantially perpendicular to and in the path of the advancing front; injecting the fluid through the well and advancing the displacement front along the leg; and producing the production well to recover oil from the reservoir.

DESCRIPTION OF THE DRAWINGS

FIGS. 1a and 1b are top plan and side views schematically showing a sand pack with simulated injection and production wells completed in a common horizontal plane, as was the case in experimental run 1-D reported on below;

FIGS. 2a and 2b are top plan and side views schematically showing a sand pack with simulated vertical injection well and perpendicular, horizontal production wells completed high and low in the pack, respectively, as was the case in experimental run 2-D reported on below;

FIG. 3 is a perspective view schematically showing a sand pack with a linear array of simulated injection wells and a simulated perpendicular, horizontal well, completed high and low respectively in the pack, as was the case in experimental runs 3-D and 4-W reported on below;

FIGS. 4a and 4b are top plan and side views schematically showing a staggered arrangement of simulated wells completed in the sand pack with a vertical injection well and a pair of parallel, spaced apart, perpendicular, horizontal wells, completed high and low respectively in the pack, as was the case in experimental run 5-D reported on below;

FIGS. 5a, 5b and 5c are top plan, side and end views of a test cell used in the experimental runs reported on below;

FIG. 6 is a flow diagram showing the laboratory set-up, including the test cell of FIGS. 5a-5c, used to conduct the experimental runs reported on below;

FIGS. 7a and 7b are isotherm maps developed in the sand pack during run 1-D (prior art configuration), taken along the horizontal and vertical mid-planes respectively;

FIGS. 8a and 8b are the isotherm maps developed in the sand pack during run 2-D, taken along the horizontal and vertical mid-planes respectively;

FIGS. 9a and 9b are the isotherm maps developed in the sand pack after 45 minutes of combustion during run 3-D, taken along horizontal planes close to the top and bottom of the pack, respectively;

FIGS. 9c, 9d, 9e and 9f are the isotherm maps developed in the sand pack along the vertical mid-plane after 45, 240, 360 and 460 minutes of combustion, respectively, during run 3-D;

FIG. 10 is a plot showing the cumulative production of the oil in place (expressed in percent) for runs 1-D, 2-D and 5-D;

FIG. 11 is a plan view showing a preferred field embodiment of the well layout;

FIG. 12 is a side cross-section of the well arrangement of FIG. 11.

FIG. 13 is a perspective view of the reservoir in the injection well and production well layout; and

FIGS. 14a, 14b, 14c, 14d, 14e and 14f illustrate various phases of the combustion process according to the layout shown in FIGS. 11 and 12.

BEST MODE OF THE INVENTION

The invention was developed in the course of carrying out an experimental investigation involving test runs carried out in a test cell or three dimensional physical model.

More particularly, a test cell 1, shown in FIGS. 5a, 5b, 5c and 6, was provided. The cell comprised a rectangular, closed, thin-walled stainless steel box 2. Dimension-wise, the box 2 formed a chamber 3 having an area of 40 square centimetres and height of 10 centimetres. The thickness of each box wall was 4 millimetres. The chamber 3 was filled with a sand pack 4 consisting of a mixture of sand, oil and water. The composition of the uniform mixture charged into the chamber 3 was:

sand- 83-87 wt. %

oil- 11-14 wt. %

water- 2-3 wt. %

The porosity of the sand pack 4 was about 30% and the permeability was about 10 darcys.

The loaded cell box 2 was placed inside a larger aluminum box 5 and the space between them was filled with vermiculite powder insulation.

Sixty type K thermocouples 6, positioned at 6 cm intervals as shown in FIGS. 5a, 5b, 5c and 6, extended through the wall of the cell 1 into the sand pack 4, for measuring the three dimensional temperature distribution in the sand pack 4.

To compensate for heat losses, the cell 1 was wound with heating tape (not shown). This heat source was controlled manually, on demand, in response to the observed combustion peak temperature and adjacent wall temperature values. The temperature at the wall of the cell was kept a few degrees ° C. less than the temperature inside the sand, close to the wall. In this way, the quasi-adiabatic character of the run was assured.

A cell heater 7 was embedded in the top section of the sand pack 4 at the air injection end, for raising the temperature in the region of the injection well 8 to ignition temperature.

One or more simulated air injection wells 8 were provided at the injection end of the cell 1. A simulated production well 9 was provided at the opposite or production end of the cell 1.

The positioning and vertical or horizontal disposition of the wells 8, 9 are shown schematically in FIGS. 1a, 1b, 2a, 2b, 3, 4a and 4b for the five test runs reported on below.

As shown in FIGS. 1a, 1b for run 1-D, the air injection and production wells 8, 9 were short and coplanar. They were both completed under the horizontal mid-plane of the sand pack 4. This arrangement simulated vertical injection and production wells completed at about the same depth. As shown in FIGS. 2a, 2b for run 2-D, the air injection well 8 was short and positioned relatively high in the sand pack 4. The production well 9 was horizontal, elongated, positioned low in the sand pack 4 relative to the injection well 8 and positioned with its toe 10 adjacent to but spaced from the injection well. As shown in FIG. 3 for runs 3-D and 4-W, a row 11 of vertical injection wells 8, positioned laterally across the sand pack 4, were provided. The injection wells were located relatively high in the sand pack. The production well 9 was horizontal, elongated, positioned low in the sand pack and had its toe adjacent to but spaced from the injection wells. As shown in FIGS. 4a, 4b for run 5-D, a single vertical air injection well 8 was provided high in the sand pack 4 and a pair of horizontal production wells 9 were provided low in the pack. The production wells were laterally spaced relative to the injection well, to provide a staggered line drive system.

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All of the horizontal production wells 9 were arranged to be generally perpendicular to a laterally extending combustion front developed at the injection source. However, the toe 10 of the production well was spaced horizontally away from a vertical projection of the injection well.

Each of the injection and production wells 8, 9 were formed of perforated stainless steel tubing having a bore 4 mm in diameter. The tubing was covered with 100 gauge wire mesh (not shown) to exclude sand from entering the tubing bore.

The combustion cell 1 was integrated into a conventional laboratory system shown in FIG. 6. The major components of this system are now shortly described.

Air was supplied to the injection well 8 from a tank 19 through a line 20. The line 20 was sequentially connected with a gas dryer 21, mass flowmeter 22 and pressure gauge 23 before reaching the injection well 8. Nitrogen could be supplied to the injection well 8 from a tank 24 connected to line 20. Water could be supplied to the injection well 8 from a tank 27 by a pump 25 through line 26. Line 26 was connected with line 20 downstream of the pressure gauge 23. A temperature controller 28 controlled the ignition heater 7. The produced fluids passed through a line 30 connected with a separator 31. Gases separated from the produced fluid and passed out of the separator 31 through an overhead line 32 controlled by a back pressure regulator 33. The regulator 33 maintained a constant pressure in the test cell 1. The volume of the produced gas was measured by a wet test meter 34 connected to line 32. The liquid leaving the separator was collected in a cylinder 40.

Part of the produced gas was passed through an oxygen analyzer 36 and gas chromatograph 37. Temperature data from the thermocouples 6 was collected by a computer 38 and gas composition data was collected from the analyzer 36 and gas chromatograph 37 by an integrator 39.

Air was injected at a rate of approximately 0.243 sm³/hr. and ignition was initiated using the heater 7. The tests were typically continued for up to 22 hours. In the run where water was added, its rate was approximately 0.43 kg/hr.

Following completion of each run, an analysis of the cell sand pack 4 was undertaken to determine the volumetric sweep efficiency. The analysis comprised a physical removal of successive vertical layers of the sandpack at 3 cm intervals and determining the extent of the burned zone by measuring the oil and coke content. In this way the volumetric sweep of the burning front was determined post-mortem and compared with that obtained from the peak temperature profiles during the run.

The relevant results for the runs are set forth in Table I.

TABLE I

Run	Con-figuration	Volume Swept %	Air-Oil Ratio (SM ³ /M ³)	Average Gravity (°API) Of Produced Oil
1-D	FIG. 1	58.7	2045	14
2-D	FIG. 2	53.0	1960	19-21
3-D	FIG. 3	66	—	19-21
4-W	FIG. 3	77	923	19-21
5-D	FIG. 4	69.5	1554	15

Legend:

D = dry in situ combustion

W = moderate wet combustion

FIGS. 7a and 7b show the isotherm or temperature contour maps developed along the horizontal mid-plane and the central vertical mid-plane, respectively, in the sand pack after 930 minutes of combustion during run 1-D, using the

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well configuration of FIGS. 1a and 1b. (This run was carried out using conventional vertical well placement.)

The nature and extent of the volume swept by the combustion front is indicated by the isotherms. It will be noted that, in the plan view of FIG. 7a, the combustion front was relatively narrow towards the production well side. Large volumes of oil were left substantially unheated on each side of the sand pack. On the other hand, the central vertical mid-plane isotherms in FIG. 7b show that the leading edge of the maximum recorded temperature (>350° C.), in the region closed to the production well, is already located in the upper third of the layer. These results are indicative of gas override.

FIGS. 8a and 8b show isotherm maps developed along the horizontal mid-plane and the central vertical mid-plane, respectively, in the sand pack after 999 minutes of combustion during run 2-D, using the well configuration of FIGS. 2a and 2b. As shown, the isotherms indicate that the combustion front was substantially wider than that of Run 1 and more upright.

FIGS. 9a and 9b show isotherm maps developed along horizontal planes at the top and bottom of the sand pack after 45 minutes of combustion during Run 3-D, using the well configuration of FIG. 3. FIGS. 9c, 9d, 9e and 9f show isotherm maps developed along the central vertical plane of the sand pack after 45, 240, 360 and 460 minutes respectively. The isotherms demonstrate that the combustion front generated by the row of injection wells extended laterally, remained generally linear and was generally upright throughout the test. Stated otherwise, the lateral and vertical sweep was much improved relative to that of Run 1-D. This run 3-D demonstrated the preferred form of the invention.

In the preferred field embodiment of the invention, illustrated in FIGS. 11 and 12 and 13, a reservoir 100 is characterized by a downward dip and lateral strike. A row 101 of vertical air injection wells 102 is completed high in the reservoir 100 along the strike. At least two rows 103, 104 of production wells 105, 106, having generally horizontal legs 107, are completed low in the reservoir and down dip from the injection wells, with their toes 108 closest to the injection wells 102. The toes 108 of the row 103 of production wells 105 are spaced down dip from a vertical projection of the injection wells 102. The second row 104 of production wells 106 is spaced down dip from the first row 103. Generally, the distance between wells, within a row, is considerably lower than the distance between adjacent rows.

The phases of the process are set forth in FIGS. 14a-14f and are described as follows. In the first phase of the process (FIG. 14a), a generally linear combustion front C is generated in the reservoir 100 by injecting air through every second well 110 of the injection wells 102. Preferably a generally linear lateral combustion front is developed by initiating combustion at every second well 110 and advancing these fronts laterally until the other unused wells 102 are intercepted by the combustion front C and by keeping the horizontal production wells 105, 106 closed. Then, air is injected through all the wells 102 (FIG. 14b) in order to link these separate fronts to form a single front C. The front C is then propagated down dip (FIGS. 14c, 14d) toward the heel 109 of the first row 103 of production wells 105. The horizontal legs 107 of the production wells 105 are generally perpendicular to the front C. The production wells 105 are open during this step, to create a low pressure sink to induce the front to advance along their horizontal legs 107 and to provide an outlet for the heated oil. When the front C approaches the heel 109 of each production well 105, the well is closed in. The horizontal legs 107 of the closed-in

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wells 105 are then filled with cement 111 (FIG. 14e). The wells 105 are then perforated 112 high in the reservoir 100 (FIG. 14f) and converted to air injection, thereby continuing the propagation of a combustion front toward the second row 104 of production wells 106. Preferably, the first row 101 of injection wells is converted to water injection, for scavenging heat in the burnt out zone and bringing it ahead of the combustion zone. This process is repeated as the front progresses through the various rows of production wells.

By the practise of this process, a guided combustion front is caused to move through the reservoir with good volumetric sweep efficiency.

The embodiments of the invention in which an exclusive property or privilege is claimed are defined as follows:

1. A process for reducing the viscosity of oil and recovering it from an underground oil-containing reservoir, comprising:

providing an injection well, completed relatively high in the reservoir, for injecting a gaseous fluid into the reservoir to form an advancing, laterally extending displacement front operative to reduce the viscosity of reservoir oil;

providing at least one open production well having a horizontal leg completed relatively low in the reservoir and positioned substantially perpendicular to and in the path of the advancing displacement front;

injecting the fluid through the injection well and advancing the displacement front along the leg; and

producing the production well to recover reduced-viscosity oil from the reservoir.

2. An in-situ combustion process for recovering oil from an underground oil-containing reservoir, comprising:

providing a generally linear air injection source completed relatively high in the reservoir;

providing at least one open production well comprising a horizontal leg having a toe and heel and being completed relatively low in the reservoir and positioned generally perpendicularly to the injection source so as to lie in the path of a combustion front established by the source;

injecting air through the injection source and initiating and propagating a combustion front, extending laterally

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of the production well horizontal leg, so that it advances toward and along the leg; and

producing the production well to recover heated oil from the reservoir.

3. The process as set forth in claim 2 wherein:

the air injection source comprises a generally linear array of vertical injection wells and the toe of the horizontal leg is adjacent to but offset from the injection wells.

4. The process as set forth in claim 2 or 3 wherein:

the reservoir extends downwardly at an angle to have dip and strike;

the injection source extends generally along the strike and the horizontal leg of the production well extends along the dip.

5. The process as set forth in claim 3 wherein:

the reservoir extends downwardly at an angle to have dip and strike;

a plurality of production wells as aforesaid are provided, said production wells being arrayed in at least two spaced apart rows parallel with the array of injection wells, which are located at the uppermost part of the oil reservoir; and

the rows of injection wells and production wells extend along the strike and the horizontal legs of the production wells extend along the dip.

6. The process as set forth in claim 5 comprising:

closing each production well in the first row as the combustion front approaches the heel of its horizontal leg;

filling the horizontal legs of the closed production wells in the first row with cement, re-completing the wells high in the reservoir and converting them to air injection wells; and

initiating air injection through the converted wells to advance a combustion front toward the second row of production wells and along their horizontal legs.

7. The process as set forth in claim 6 comprising:

injecting water through the array of original air injection wells in the course of injecting air through the converted wells.

* * * * *

Disclaimer

5,626,191—Malcolm Greaves, Avon, United Kingdom; Alexandru T. Turta, Calgary, Canada. OILFIELD IN-SITU COMBUSTION PROCESS. Disclaimer filed February 2, 2002, by assignee, Alberta Research Council Inc.

Hereby enters this disclaimer to claim 1.

(Official Gazette, March 26, 2002.)

United States Patent [19]

Shu et al.

[11] Patent Number: 4,598,770

[45] Date of Patent: Jul. 8, 1986

[54] THERMAL RECOVERY METHOD FOR VISCOUS OIL

[75] Inventors: Winston R. Shu, Dallas; Kathy J. Hartman, Arlington, both of Tex.

[73] Assignee: Mobil Oil Corporation, New York, N.Y.

[21] Appl. No.: 664,740

[22] Filed: Oct. 25, 1984

[51] Int. Cl.⁴ E21B 43/24

[52] U.S. Cl. 166/245; 166/50; 166/52; 166/272

[58] Field of Search 166/272, 263, 303, 50, 166/52, 245

[56] References Cited

U.S. PATENT DOCUMENTS

4,248,302	2/1981	Churchman	166/272
4,296,969	10/1981	Willman	166/272 X
4,344,485	8/1982	Butler	166/50 X
4,385,662	5/1984	Mullins et al.	166/263

4,434,849	3/1984	Allen	166/50 X
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4,466,485	8/1984	Shu	166/272
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Oil and Gas Journal, Aug. 23, 1982, pp. 51-54.

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SPE Paper 82-33-68, Pugh.

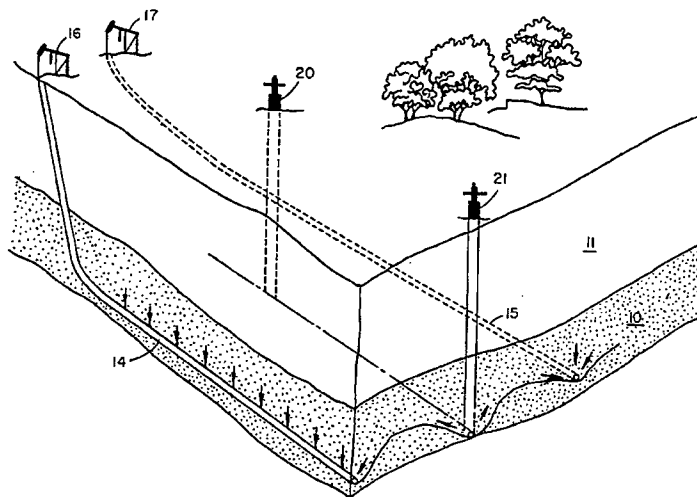
Primary Examiner—Stephen J. Novosad

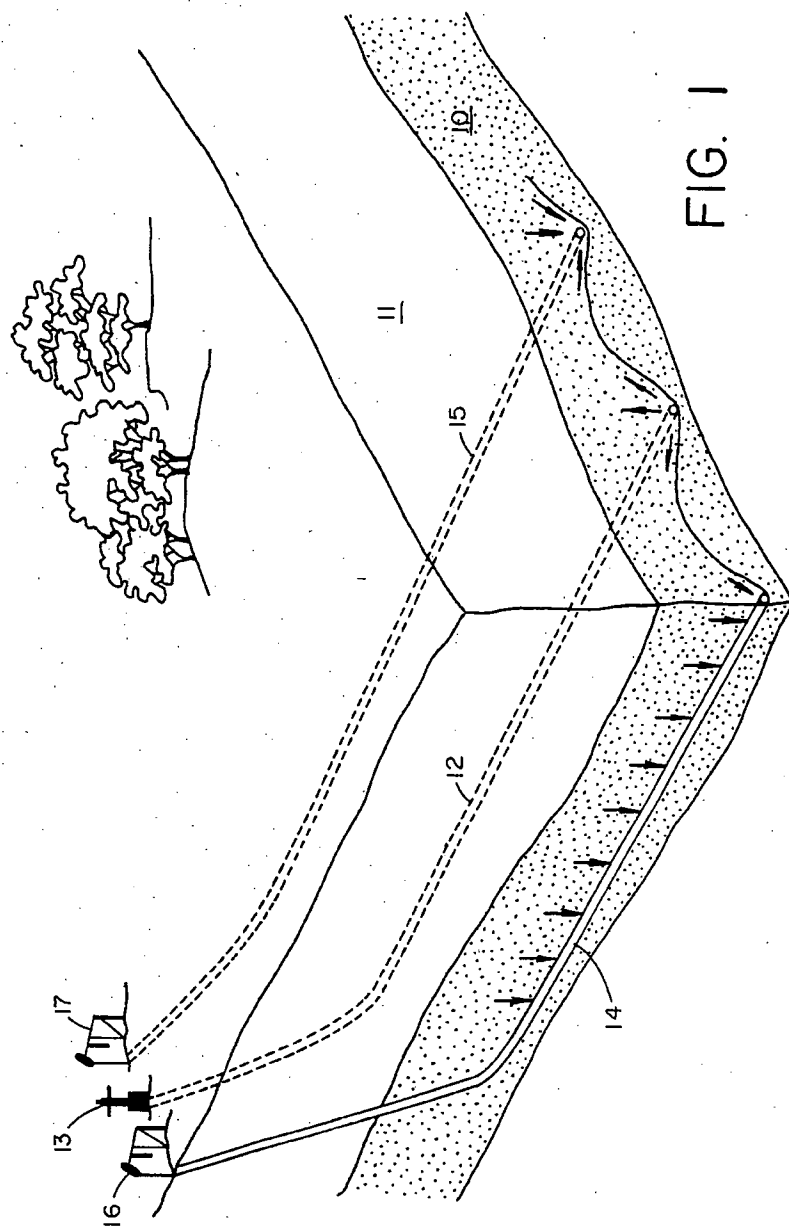
Attorney, Agent, or Firm—A. J. McKillop; Michael G. Gilman; George W. Hager, Jr.

[57] ABSTRACT

A thermal oil recovery process in which steam is injected into a heavy oil-bearing formation through a horizontally-drilled injection well and oil is produced through a horizontal production well parallel to the injection well.

2 Claims, 5 Drawing Figures





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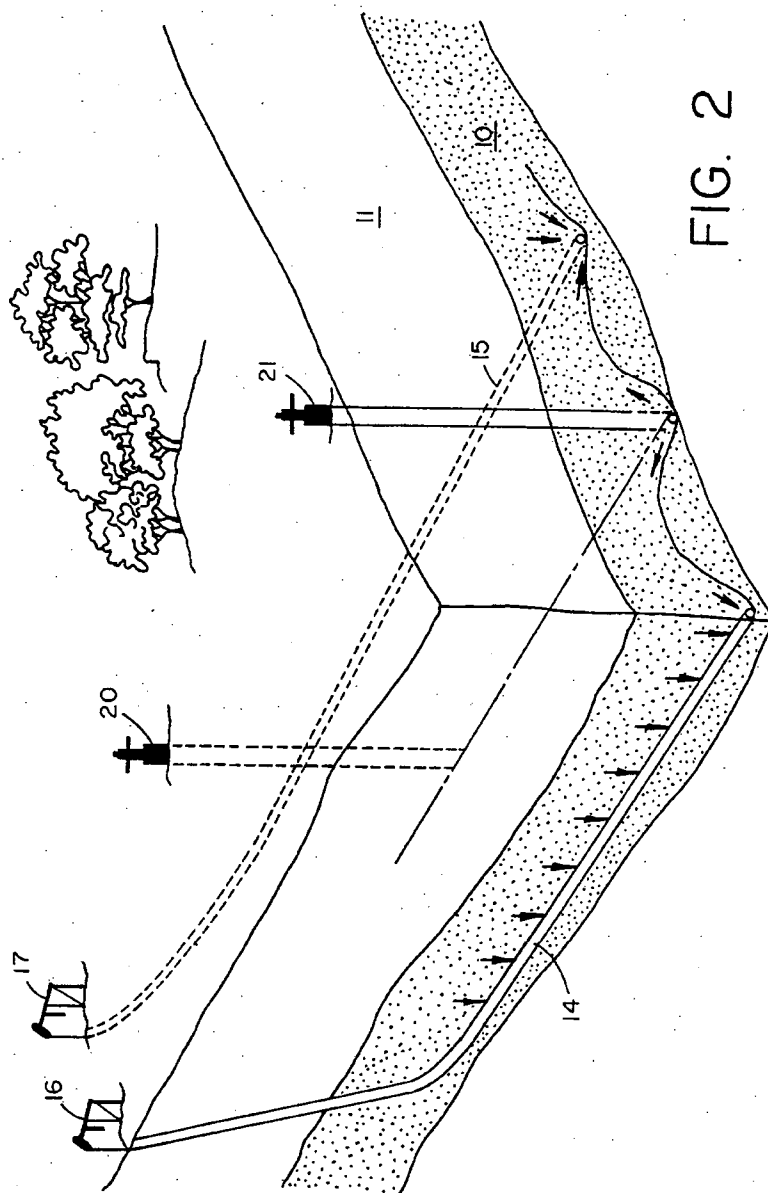


FIG. 2

FIG. 3

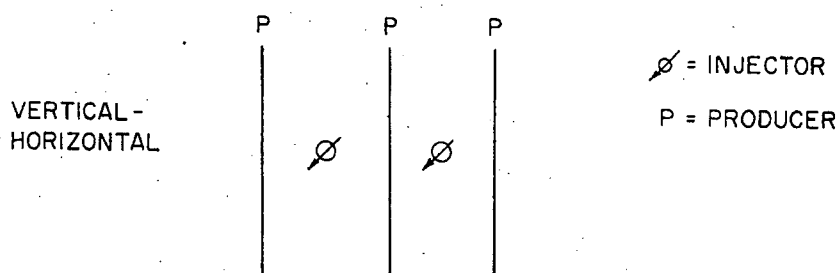
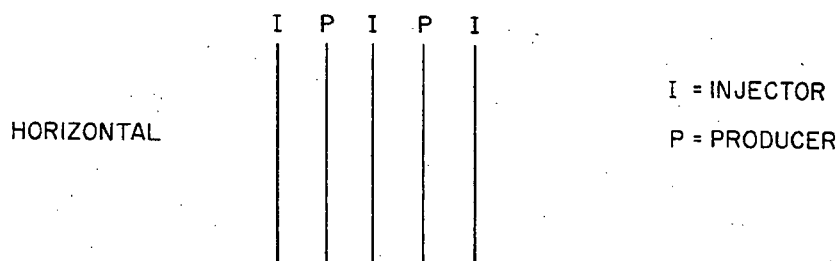
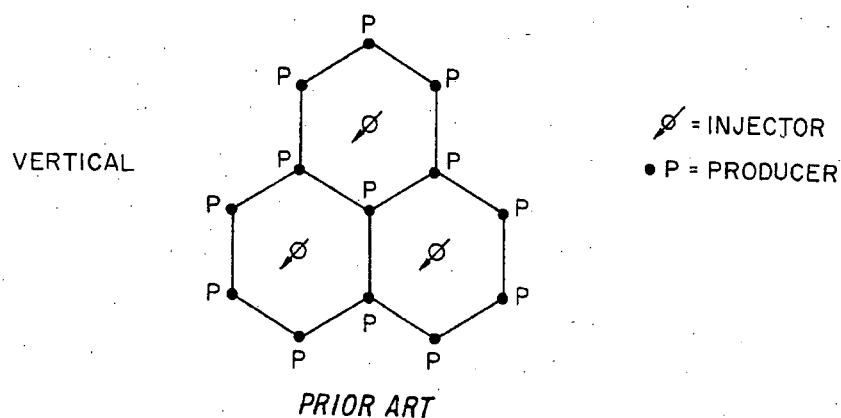
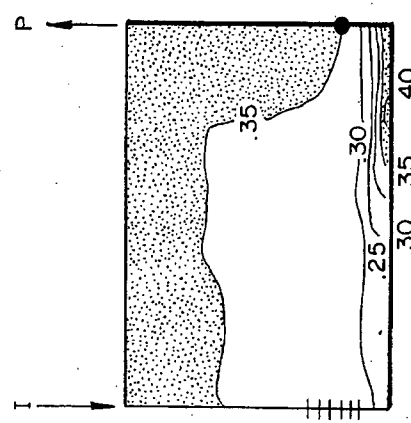
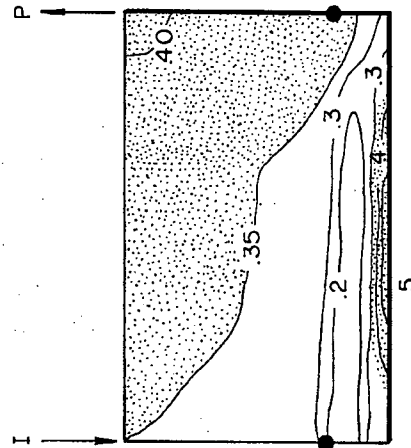


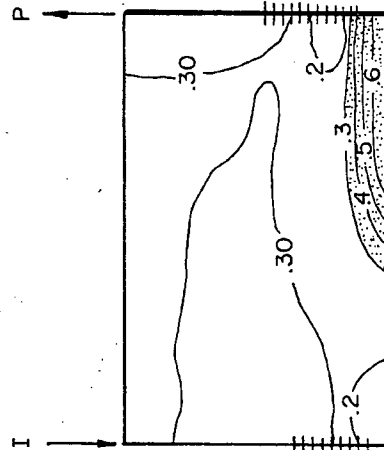
FIG. 4



VERTICAL
HORIZONTAL WELL COMBINATION
AT 1290 DAYS

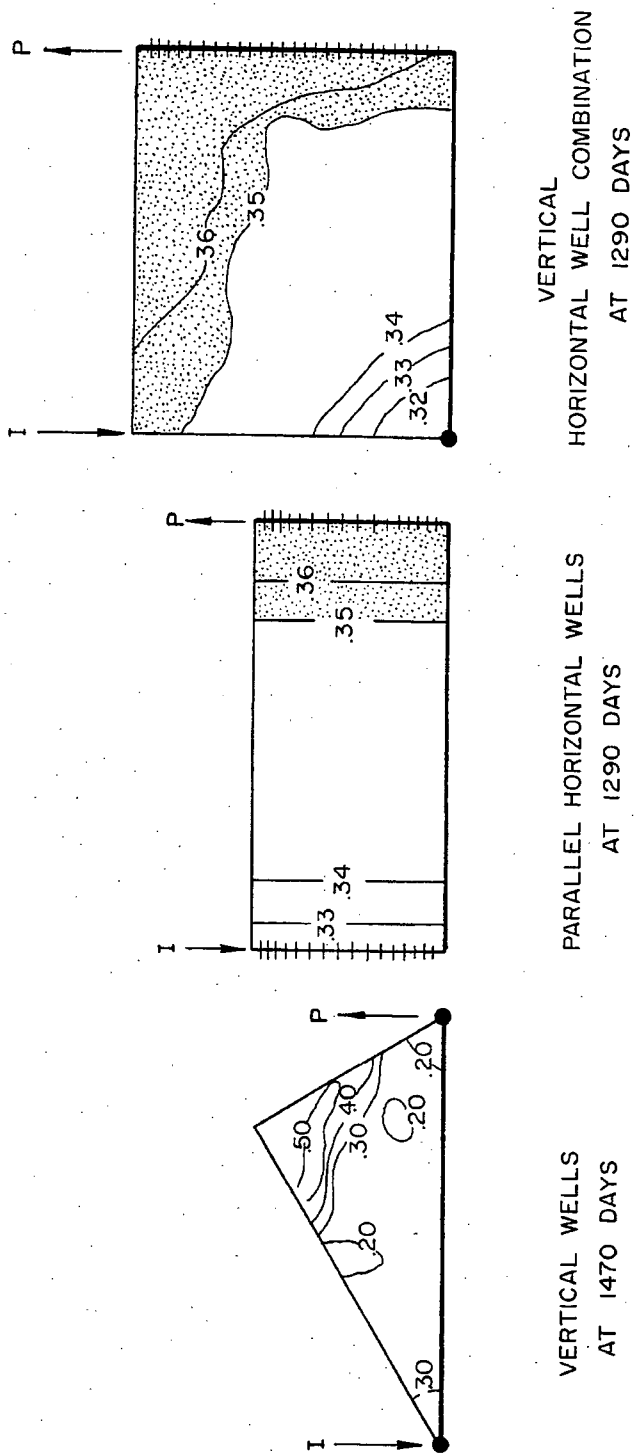


PARALLEL HORIZONTAL WELLS
AT 1290 DAYS



VERTICAL WELLS
AT 1470 DAYS

FIG. 5



THERMAL RECOVERY METHOD FOR VISCOUS OIL

FIELD OF THE INVENTION

This invention relates to a thermal recovery process for recovering viscous oils from subterranean formations. In particular, the invention relates to an improved steam flooding method for recovering such oils.

BACKGROUND OF THE INVENTION

There are many subterranean formations containing heavy, i.e. viscous, oils from which the oil cannot be recovered by conventional methods because the oil is too viscous to flow to the production wells without some form of assistance. Such formations are known to exist in the major tar sand deposits of Alberta, Canada and Venezuela with lesser deposits elsewhere, for example, in California, Utah and Texas. The API gravity of the oils in these deposits typically ranges from 10° to 6° in the Athabasca, Alta. deposits to even lower values in the San Miguel sands in Texas, indicating that the oil is of a highly viscous nature.

Various methods have been proposed for recovering the oil in these deposits now that reserves of more easily recovered oils are decreasing, at least in the politically stable areas of the world. These methods include in-situ combustion methods in which part of the oil in the reservoir is burnt by the injection of air or oxygen through an injection well to generate heat so as to reduce the viscosity of the oil and to produce a degree of cracking; the resulting less viscous, cracked oil then acts as a solvent for the heavy oil in place. Solvent recovery techniques have also been proposed, for example in U.S. Pat. Nos. 4,373,585 and 4,293,035, in which a solvent for the heavy oil is injected into the reservoir to form a less viscous solution which can then be recovered by more conventional means. Another technique which has been proposed and used in various forms is steam flooding, in which steam is injected into the formation through an injection well, to heat the formation and, in so doing, to reduce the viscosity of the oil and possibly also, to induce a degree of cracking, resulting in a further reduction in viscosity. Processes of this type can be generally classified as basically of the two well or one well type. In the two well or steam drive type, the steam is injected through an injection well and the injected steam serves to drive the oil towards a separate production well which is located at some horizontal distance (offset) from the injection well. In the one-well or "huff and puff" type operation, a single well is used for both injection and production. The steam is first injected to reduce the viscosity of the oil and to pressurize the formation; after a certain amount of time, steam injection is terminated and the well is turned over to production. A soak period may be allowed to permit the heat to permeate the reservoir to a greater extent before production is initiated in either type of operation. Whether the process is classified as of the one-well or two well types, the well arrangement can, of course, be repeated to cover the field in the manner desired. For example, the two well arrangement may be repeated in regular patterns such as the inverted five spot or inverted seven spot patterns, as described in U.S. Pat. No. 3,927,716. The present method relates basically to the two well type operation, using an injection well or wells and a

separate production well or wells at an offset from the injection well.

Horizontally drilled wells have been proposed in various applications, for example, in solvent recovery processes, as described in U.S. Pat. No. 4,385,662 as well as for offshore primary recovery operations as described, for example, in Ocean Industry, June 1984, 35-36 and in certain steam flooding operations mentioned in the Ocean Industry article.

Among the steam flooding operations using horizontal wells are the Kern River, California "huff and puff" project described in the Oil and Gas Journal, 23 August 1982, 51-54, this project also including conventional vertical steam injection wells bisecting the lateral wells. The Cold Lake, Alta. project which used horizontal wells is believed to be of the single well ("huff and puff") type also; the project has been described in Paper No. 79-30-10 of the Petroleum Society of CIM, presented in Banff, Alta. 8-11 May 1979. A similar project was operated at Fort McMurray, Alta, as described in Paper No. 82-33-68 of the Petroleum Society of CIM, presented 6-9 June 1982 in Calgary, Alta., Petroleum Engineer International, September 1982, 40-52. In addition, U.S. Pat. No. 4,248,302 discloses a steam flood recovery method using a highly deviated injection well with production wells situated along the line of the injection well. This proposal has the disadvantages that not only is a relatively large number of production wells required but, in addition, correct positioning of these wells over the injection points is difficult.

Steam flooding processes using horizontal fractures for injecting the steam have been proposed in U.S. Pat. Nos. 3,375,870 and 4,265,310.

U.S. Pat. No. 4,466,485 describes a viscous oil recovery method which employs a steam injection well which extends through the formation in a horizontal direction. The production well is in the conventional vertical position and is completed in the upper two-thirds of the formation. A particular production cycle is employed to maximize recovery but because of the vertical disposition of the production wells, complete drainage of the formation is not assured.

SUMMARY OF THE INVENTION

According to the present invention, viscous oils are recovered from subterranean formations by a steam flooding operation using at least one horizontally drilled production well. The steam may be injected either through injection wells arranged vertically in the conventional manner, at an offset from the horizontal production well or, alternatively, a horizontal injection well may be used. Generally, it is preferred that the injection wells should be arranged along a line between two of the horizontal production wells in order to achieve maximum steam utilization and to optimize reservoir drainage into the production wells. The production wells will normally be situated near the bottom of the production interval to ensure that drainage is as complete as possible, thereby maximizing recovery.

DRAWINGS

FIG. 1 is a simplified representation of a recovery operation using horizontal injection and production wells;

FIG. 2 is a simplified representation of a recovery operation using horizontal production wells and vertical injection wells;

FIG. 3 is a schematic showing the well patterns used in the experimental simulations described below;

FIG. 4 is a comparison of the residual oil saturations obtained with the simulated production runs described below (vertical contours);

FIG. 5 is a comparison of the residual oil saturations obtained with the simulated production runs described below (horizontal contours).

DETAILED DESCRIPTION

FIG. 1 shows the preferred well pattern for carrying out the present production method. A subterranean heavy oil formation 10 underneath an overburden 11 has a horizontal steam injection well 12 extending from surface injection head 13 in a substantially straight line along the bottom of the production interval. Two horizontal production wells 14, 15 also run through reservoir 10 at the bottom of the production interval, with their horizontal portions parallel to injection well 12. At the surface, the production wells are connected to suitable wellhead equipment 16, 17 for producing the fluids which enter the wells.

In operation, steam is injected into injection well 12 and thence into formation 10 where it heats the formation and the oil in place in the reservoir to the appropriate temperature for recovery through the production wells.

An alternative arrangement is depicted in FIG. 2 in which vertical steam injection wells 20, 21 are disposed along a line parallel to and centrally between horizontal production wells 14, 15. The injector wells are completed at the bottom of the production interval and the horizontal production wells again, run along the bottom of the production interval. Wellhead equipment 16, 17 is provided as previously described.

Because the steam from the injector wells tends to rise in the reservoir after it leaves the injection well, the injection wells should preferably be completed in the lower portion of the production interval. However, to minimize heat losses to the non-pay zone beneath and to minimize channelling of steam under the pay zone, it may be desirable to position the horizontal injection well or to complete the vertical injection well, as appropriate, somewhat above the bottom of the production interval; e.g. at 80% or 90% of the vertical distance down the interval. Because the oil which has been heated by the steam will descend through the reservoir, taking with it some of the oil in place, positioning the injector at some distance up in the reservoir will not necessarily lose production because the descending, heated oil, together with entrained reservoir oil, will drain into the production wells at the bottom of the interval. Thus, the use of the horizontal producing wells establishes a vertical sweep of high efficiency in the reservoir. Area sweep may be up to almost 100 percent because of the greater reservoir area exposed to the producing wells.

The horizontal separation or offset between the line of injectors and the production wells needs to be chosen according to reservoir characteristics; e.g. nature of oil, matrix porosity, permeability and so forth. This may be determined by reference to the known characteristics of the reservoir prior to siting the wells. The well pattern may, of course, be repeated in order to cover the production field to the extent desired. Generally, it has been found that one horizontal well can replace about 2.5 to 3.8 vertical wells in a parallel horizontal injector/producer pattern, depending upon the vertical per-

meability of the formation; in a vertical injector/horizontal producer operation, one horizontal well can generally replace about 1.6 to 2.4 vertical producers. In an infinitely repeated vertical injector/horizontal parallel producer pattern, the injectors should be situated on the center line between the parallel producers with a separation equal to the separation between the producers. In this case, therefore, the number of vertical injectors between each pair of producers will be equal to the quotient of the length of the horizontal producers and their separation. The economics of the operation should therefore be considered at the outset since horizontal wells are more expensive to drill than vertical wells. The advantages of horizontal wells over vertical wells increase with an increasing ratio of vertical to horizontal permeability for the reservoir: as the ratio increases, residual oil saturation in the upper part of the reservoir will decrease, to give a better vertical sweep efficiency resulting from the improved drainage into the production wells.

Operating conditions for the steam flooding process should be chosen in accordance with known reservoir characteristics such as permeability, nature of oil and so forth. The operating procedure may follow conventional principles or may be adjusted suitably to take the greatest opportunity of exploiting the advantages of the present invention. For example, steam injection rates may typically be from 1.5 to 2.0 barrels/day/acre-foot CWE (cold water equivalent) (from about 385 to 260 l./day/1000 m³ CWE). Total amount of steam injected will depend primarily on reservoir thickness, temperature and thermal conductivity together with the characteristics of the oil; e.g. the extent to which it is affected physically and chemically by the steam. Typically, steam temperature will be from 200° to 400° C. (about 400° to 750° F.); temperatures at the higher end of this range will generally tend to promote cracking of the oil in the reservoir to produce a vis-broken oil of low viscosity which facilitates an enhanced degree of recovery of the reservoir oil, as compared to a non-visbroken oil that has merely been subjected to heating by lower temperature steam. Steam temperature is determined by its pressure of injection which, in turn, will depend upon the reservoir characteristics; e.g. reservoir pressure and can be readily determined. Steam quality may also be selected according to the desired amount of net heat to be injected but normally should lie between 0.4 to 0.8 for a safe and efficient operation of the steam generator.

The production operations may be run with either rate control or pressure control. In the former, a predetermined liquid flow rate is maintained by adjusting the bottomhole pressure at the injector. With pressure control, free flow of liquids is allowed by maintaining constant bottomhole pressure, assuming that pump capacity is adequate to remove all the fluids produced. Depending upon reservoir characteristics, it may be more advantageous to operate with rate control in order to achieve maximum production, although it may take longer to do it; the economics of the individual modes of operation should therefore be given appropriate consideration in each case.

Experimental

Vertical Well Pattern

Using computer modelling techniques, a reservoir volume equivalent to about one-twelfth of an infinitely

repeated seven spot vertical well pattern was simulated, as shown in FIG. 3. The model therefore assumed use of 1/12 of the injector and 1/6 of a producer. The equivalent area for the pattern was 6.9 acres (2.8 ha) thus giving a simulated area of 0.575 acre (0.23 ha), at a well distance of 341 ft (104 m).

The injector was completed in the 195 ft. (59 m) pay zone for an interval of 60 ft (18.3 m) and the producer 90 ft (27.4 m), each starting just above a 15 ft (4.6 m) water layer ($S_w=0.81$). Initial reservoir temperatures were 60° C. (140° F.) and 790 kPa (100 psig), respectively.

Steam of 60% quality was injected at 285° C. (545° F.) and 3200 kPa (450 psig), respectively, at an injection rate of 376 hl/day (237 bbl/day) for one-twelfth of an injector. The production well was placed on rate control with a maximum liquid rate of 477 hl/day (300 bbl/day), equivalent to 211 l/day/1000 m³ (1.65 bbl/day/acre-foot).

Criteria used for determining the time of steam breakthrough were: live steam production, a significant drop in the oil production rate and a significant increase in the water:oil ratio (water:oil greater than 20:1).

Horizontal Well Pattern

A parallel horizontal well pattern, i.e., an infinitely repeated pattern of injectors and producers horizontal and parallel to one another, as shown in FIG. 3, of equivalent surface area to 1/6 of the vertical well pattern, using the same well separation of 104 m (341 ft). The resulting length of horizontal well simulated was therefore 45.3 m (148.5 ft). To cover an area equivalent to the entire seven spot vertical pattern, the horizontal wells would be six times as long, about 271 m (891 ft). The horizontal wells were placed 12 m (40 ft) from the bottom of the pay zone.

The injection of steam was stimulated using the same conditions as for the vertical well pattern.

For simulation purposes, the horizontal well pattern was tested with both rate control and pressure control.

Vertical-Horizontal Well Combination

An infinitely repeated well pattern having vertical injection wells and horizontal producers, as shown in FIG. 3, was also simulated. In this case, simulated area was equivalent to one quarter of the 7-spot vertical pattern, using a horizontal offset of 90 m (295 ft) between the vertical injector and the horizontal producer. The vertical well was completed for 18.3 m (60 ft) in the pay zone, as in the vertical well situation, and the horizontal well was situated 10.7 m (35 ft) above the water layer. The length of the horizontal well in the simulated area was about 152 m (500 ft).

Steam injection was simulated under the same conditions as for the other cases, using both rate and pressure control. The results are given in Table 1 below.

TABLE 1

Comparison of Well Patterns			
Pattern	Vertical	Horizontal	Vertical-Horizontal
Breakthrough Time, Days	1470	1290	1290
Injection, MBBL	3862	3471	3672
Production			
Oil, MBBL	575.0	481.4	455.6
Oil, %	33.5	28.0	26.5

TABLE 1-continued

Comparison of Well Patterns			
Pattern	Vertical	Horizontal	Vertical-Horizontal
Water, MBBL	4175.4	4053	4232
Ratios			
Oil/Steam	0.149	0.139	0.124
Cumulative Water/Oil	7.26	8.42	9.29

Notes:

- (1) Injection and Production figures on equivalent 7-spot acreage basis.
- (2) Percentage oil produced is percentage of original oil in place.
- (3) Results for horizontal and vertical/horizontal patterns are on pressure control.

With the parallel horizontal well pattern under pressure control, breakthrough occurred, as shown in Table 1 at 1290 days. Under rate control, breakthrough occurred later (at 1470 days) but gave a higher total oil recovery, indicating that for the reservoir studied there is likely to be an optimum production rate between the cases considered in this study.

With the vertical/horizontal well pattern, a similar result was obtained in the comparison between rate and pressure control.

Comparison of the residual oil saturation contour plots at steam breakthrough shown in FIGS. 4 and 5 indicates that each type of well pattern has a different sweep pattern. FIG. 4 compares the oil saturation contours showing the vertical sweep in the plane which contained the vertical injector. All well patterns had poor vertical sweep in areas beneath the production well elevation. The vertical well pattern had excellent vertical sweep with steam overriding and pushing oil over and down to the producer. The parallel horizontal wells had less steam override and less recovery from the upper portion of the reservoir. The vertical-horizontal well combination showed an intermediate vertical sweep with more override near the vertical injector and less near the horizontal producer.

FIG. 5 illustrates the area sweep in the horizontal plane which contained the horizontal wells, at steam breakthrough. The vertical wells left some unswept oil between two producers in the 7-spot pattern. The area sweep of the horizontal wells is, of course, uniform for a two-dimensional simulation. The combination well pattern shows a somewhat intermediate area sweep. Steam front advance is very like plug flow in blocks directly between the vertical injector and the horizontal producers. It also shows a region of unswept oil in the corner opposite the vertical injector.

We claim:

1. In a method for the enhanced recovery of a viscous oil from a subterranean, oil-bearing formation by injecting steam into the formation through at least one injection well and producing oil from a plurality of separate producing wells situated at an offset from the injection well, the improvement which comprises

- (a) a plurality of substantially parallel horizontal production wells, and
- (b) a plurality of vertical injection wells located between each pair of adjacent parallel horizontal production wells and spaced apart along the center line between each of said pairs of parallel horizontal production wells at distances equal to the separation of said parallel horizontal production wells.

2. A method according to claim 1 in which the number of said plurality of vertical injection wells situated between each pair of adjacent parallel horizontal production wells is equal to the quotient of the length of said parallel wells and the separation between said production wells.

* * * * *



INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

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(21) International Application Number: PCT/EP00/00791 (22) International Filing Date: 1 February 2000 (01.02.00) (30) Priority Data: 99300717.8 1 February 1999 (01.02.99) EP (71) Applicant (for all designated States except CA): SHELL INTERNATIONALE RESEARCH MAATSCHAPPIJ B.V. [NL/NL]; Carel Van Bylandtlaan 30, NL-2596 HR The Hague (NL). (71) Applicant (for CA only): SHELL CANADA LIMITED [CA/CA]; 400 - 4th Avenue S.W., Calgary, Alberta T2P 2H5 (CA). (72) Inventors: VAN BUREN, Markus, Antonius; PDO Office, Mina Al Fahal, 113 Muscat (OM). SUREWAARD, Jo- hannes, Henricus, Gerardus; PDO Office, Mina Al Fahal, 113 Muscat (OM).		(81) Designated States: AE, AL, AM, AT, AU, AZ, BA, BB, BG, BR, BY, CA, CH, CN, CR, CU, CZ, DE, DK, DM, EE, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, JP, KE, KG, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MA, MD, MG, MK, MN, MW, MX, NO, NZ, PL, PT, RO, RU, SD, SE, SG, SI, SK, SL, TJ, TM, TR, TT, TZ, UA, UG, UZ, VN, YU, ZA, ZW, ARIPO patent (GH, GM, KE, LS, MW, SD, SL, SZ, TZ, UG, ZW), Eurasian patent (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European patent (AT, BE, CH, CY, DE, DK, ES, FI, FR, GB, GR, IE, IT, LU, MC, NL, PT, SE), OAPI patent (BF, BJ, CF, CG, CI, CM, GA, GN, GW, ML, MR, NE, SN, TD, TG). Published <i>With international search report.</i> <i>Before the expiration of the time limit for amending the</i> <i>claims and to be republished in the event of the receipt of</i> <i>amendments.</i>
(54) Title: METHOD FOR CREATING SECONDARY SIDETRACKS IN A WELL SYSTEM		
(57) Abstract A method is disclosed for creating one or more secondary sidetracks in an oil and/or gas well assembly which comprises a primary wellbore (2) and one or more primary sidetracks (6) so that a root-like multilateral well structure is created. The method makes use of an expandable well liner (9) in the primary sidetracks (6) so as to create a liner having a sufficient internal width to allow sidetracking equipment to be inserted and operated in the primary sidetrack to drill and complete the secondary sidetracks (7).		

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METHOD FOR CREATING SECONDARY SIDETRACKS IN A WELL SYSTEM

Background of the Invention

The invention relates to a method for creating secondary sidetracks in a well system which comprises a main wellbore into which one or more primary sidetracks debouch.

Such a well system is known from International patent application WO 98/49424.

A difficulty which arises with such a well system is that conventional wells have a telescoping nature which stems from the fact that a casing is inserted into the main well at various stages of the drilling process and casing sections which are inserted thereafter need to have a smaller outer diameter than the inner diameter of the previously installed casing sections, and that the liner which is subsequently inserted into the primary sidetrack needs to have an outer diameter which is significantly smaller than the inner diameter of the casing of the main wellbore at the branchpoint in order to allow a smooth insertion of the liner from the main wellbore into the primary sidetrack.

As a result the liner of the primary sidetrack has such a small diameter that it is hardly feasible and economically unattractive to drill secondary sidetracks away from the primary sidetrack.

An object of the present invention is to provide a method for creating one or more secondary sidetracks in a well system in an efficient and economical manner.

Summary of the Invention

In accordance with the present invention a method is provided for creating a secondary sidetrack in a well system for production of hydrocarbon fluids which

- 2 -

comprises a main wellbore and a primary sidetrack which debouches into the primary wellbore, the method comprising:

- 5 - inserting an unexpanded expandable liner into the primary sidetrack;
- radially expanding the liner;
- creating an opening in the wall of the expanded liner; and
- 10 - drilling a secondary sidetrack into the hydrocarbon formation through said opening.

Preferably the expandable liner is a steel liner which is expanded by pushing or pulling an expansion mandrel which is provided with a conical wear-resistant outer surface and/or rollers through the liner.

- 15 The expanded liner has an internal diameter which is sufficiently large to allow drilling and/or kick off equipment to be inserted into the primary sidetrack for drilling of one or more secondary sidetrack, which also have an internal width which is sufficiently large to
- 20 serve as a wellbranch through which hydrocarbon fluids can flow into the well system.

- Hence the method according to the invention allows to create a root-like well system which provides an optimal drainage of hydrocarbon fluids from a hydrocarbon bearing formation, even if the formation has a low permeability.
- 25

- In an attractive embodiment of the method according to the invention the expandable liner is formed by a coiled tubing through which drilling fluid is pumped towards a downhole drilling assembly which is used to
- 30 drill the primary sidetrack and which coiled tubing is radially expanded after the primary sidetrack has been drilled.

- Also the secondary sidetrack may be drilled using a coiled tubing which is expanded to form an expanded liner
- 35 after completion of the drilling activities.

Alternatively the secondary sidetrack may be lined using an expandable slotted liner of which the slots are staggered and open up into diamond shaped apertures upon expansion of the liner. Such an expandable slotted line
5 is known from US patent No. 5,366,012. Such a slotted liner may be surrounded in the inflow region of the secondary sidetrack by an expandable sandscreen, such as a sandscreen which is disclosed in International patent application PCT/EP96/04887.

10 In stable reservoir formations the secondary sidetrack may be an open uncased hole whereas if the reservoir formation is very unstable the secondary sidetrack may be lined with an initially unslotted expanded or unexpanded liner into which perforations are
15 shot using a perforation gun which is known per se.

The invention also relates to a root-like well system which has been created in accordance with the invention and which comprises a main wellbore into which one or more primary sidetracks comprising an expanded expandable
20 liner debouch and one or more secondary sidetracks which debouch into the primary sidetrack or sidetracks through one or more openings in the wall of the expanded liner or liners.

It will be understood that the use of expandable
25 tubulars in a multilateral well system makes it possible that the well tubulars in the primary or mother well and in the primary and secondary sidetracks or well branches have a substantially equal internal width, so that a monobore multilateral well is created. In such a monobore
30 well system it is possible to drill tertiary sidetracks away from the secondary sidetracks, which sidetracking process can be repeated again and again so that a truly root-like multilateral well system is created.

Brief Description of the drawings

Preferred embodiments of the method and system according to the present invention will be described with reference to the drawings, in which:

5 Fig. 1 is a schematic vertical sectional view of a well system according to the invention; and

Fig. 2 is a schematic vertical sectional view of a well system according to the invention, which comprises a primary sidetrack into which two secondary sidetracks debouch.
10

Detailed Description of preferred Embodiments

Referring now to Fig. 1 there is shown a well system 1 according to the present invention which comprises a vertical main wellbore 2 which extends from a wellhead 3 at or near the earth surface 4 into a subsurface formation 5. Three primary sidetracks 6 debouch into the main wellbore 2. A secondary sidetrack 7 debouches into each primary sidetrack 6 through an opening 8 in the wall of an expanded expandable steel liner 9, of which only the section in the region of each opening 8 is shown.
15
20

The use of expanded liners 9 maximizes the internal width of the liners 9. Thus, if the wellbore of each sidetrack has a width of about 10 cm, the expanded liner may have an internal width of about seven to eight centimetres.
25

Such an internal width is a minimal requirement to allow a drilling assembly to be inserted into the primary sidetracks 6 which can be used to drill secondary sidetracks 7 of a sufficient width which is necessary to allow hydrocarbon fluids to flow in sufficient quantities through the secondary sidetracks 7 into the primary sidetracks.
30

Preferably also the main wellbore 2 is cased with an expandable steel casing which is cladded against the wellbore during the expansion process in a similar manner
35

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as the expandable liners 9 have been cladded against the wellbore of the primary sidetracks 6.

This allows a further increase in the internal width of the liners 9 and of the secondary sidetracks 7.

5 The primary and secondary sidetracks 6 and 7 each extend into hydrocarbon fluid bearing formations 10 which are shown as shaded areas in the drawing.

10 It will be understood that the illustrated well system provides a root-like well configuration which provides an optimum drainage of hydrocarbon fluids from the hydrocarbon fluid bearing formations 10.

Referring now to Fig. 2 there is shown a vertical primary wellbore 20 from which a primary sidetrack 21 has been drilled away in a horizontal direction.

15 The primary sidetrack 21 is lined with an expandable steel liner 22. Preferably the liner 22 is formed by a coiled tubing which has been used during drilling to feed drilling fluid to a drill bit (not shown) and to a hydraulic downhole mud motor (not shown) which is used to rotate the drill bit.

20 After completion of drilling the coiled tubing is expanded such that it is cladded against the wellbore and subsequently serves as a steel lining of the wellbore of the primary sidetrack 21.

25 Subsequently a 4.5 inch (= about 12 cm) shoe 22 and a plug 23 are installed near the toe 24 of the primary sidetrack 21 inside the liner 22.

30 Then a whipstock 25 is inserted and anchored within the liner 22 and a hanger 26 having an internal width of about 7 cm is inserted into the expanded liner 22 which has an internal width of about 10 cm. Then a drilling assembly (not shown) is inserted through the hanger 26 and is induced by the whipstock 25 to mill an opening into the liner 22 and to subsequently drill the secondary

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sidetrack 30 into a hydrocarbon fluid bearing formation 31.

5 In the example shown a conventional steel liner 31 has been inserted into the secondary sidetrack 30 which has an outer diameter of about 7 cm and which is perforated in the well inflow zone by means of a perforating gun (not shown).

10 After completion of the first secondary sidetrack 30 another whipstock 32 is inserted and anchored inside the expanded liner 22 close to the heel of the lateral primary sidetrack 21 whereupon yet another secondary sidetrack 33 is drilled and completed in the same manner as described with reference to the first secondary sidetrack 30.

15 After insertion of a steel liner 34 in the second secondary sidetrack either an opening (not shown) is drilled through the wall of the liner 34 and through the whipstock 34 or an already existing fluid passage in the whipstock and a fluid passage in the hanger 35 are used
20 to allow hydrocarbon fluid to flow from the first secondary sidetrack 30 and through the primary sidetrack 21 into the main wellbore 20.

C L A I M S

1. A method for creating a secondary sidetrack in a well system for production of hydrocarbon fluids from a hydrocarbon formation, which well system comprises a main wellbore and a primary sidetrack which debouches into the primary wellbore, the method comprising inserting an unexpanded expandable liner into the primary sidetrack and radially expanding the liner; characterized in that an opening is created in the wall of the expanded liner in the primary sidetrack; and that a secondary sidetrack is drilled into the hydrocarbon bearing formation through said opening.
2. The method according to claim 1, wherein the expandable liner is formed by a coiled tubing through which drilling fluid is pumped towards a downhole drilling assembly which is used to drill the primary sidetrack and which coiled tubing is radially expanded after the primary sidetrack has been drilled.
3. The method according to claim 1 or 2, wherein the secondary sidetrack is drilled with a drilling assembly which is connected to a coiled tubing, which tubing is expanded after the secondary sidetrack has been drilled to form a lining in the secondary sidetrack.
4. The method according to claim 1 or 2, wherein the secondary sidetrack is lined along at least part of its length with an expandable slotted liner which is expanded inside the secondary sidetrack such that a series of staggered slots in the liner open up into diamond shaped apertures.
5. The method according to claim 4, wherein an expandable sandscreen is arranged around the expandable

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slotted liner in the zone where hydrocarbon fluids flow into the well system.

5 6. The method according to claim 1, wherein an unexpandable liner is inserted into the secondary sidetrack which liner is perforated in the zone where hydrocarbon fluids flow into the well system.

7. The method according to claim 1, wherein the capillary sidetrack is uncased along at least part of its length.

10 8. The method according to claim 1, wherein a plurality of primary sidetracks debouch into the primary wellbore and wherein a plurality of secondary sidetracks debouch into at least one of the primary sidetracks.

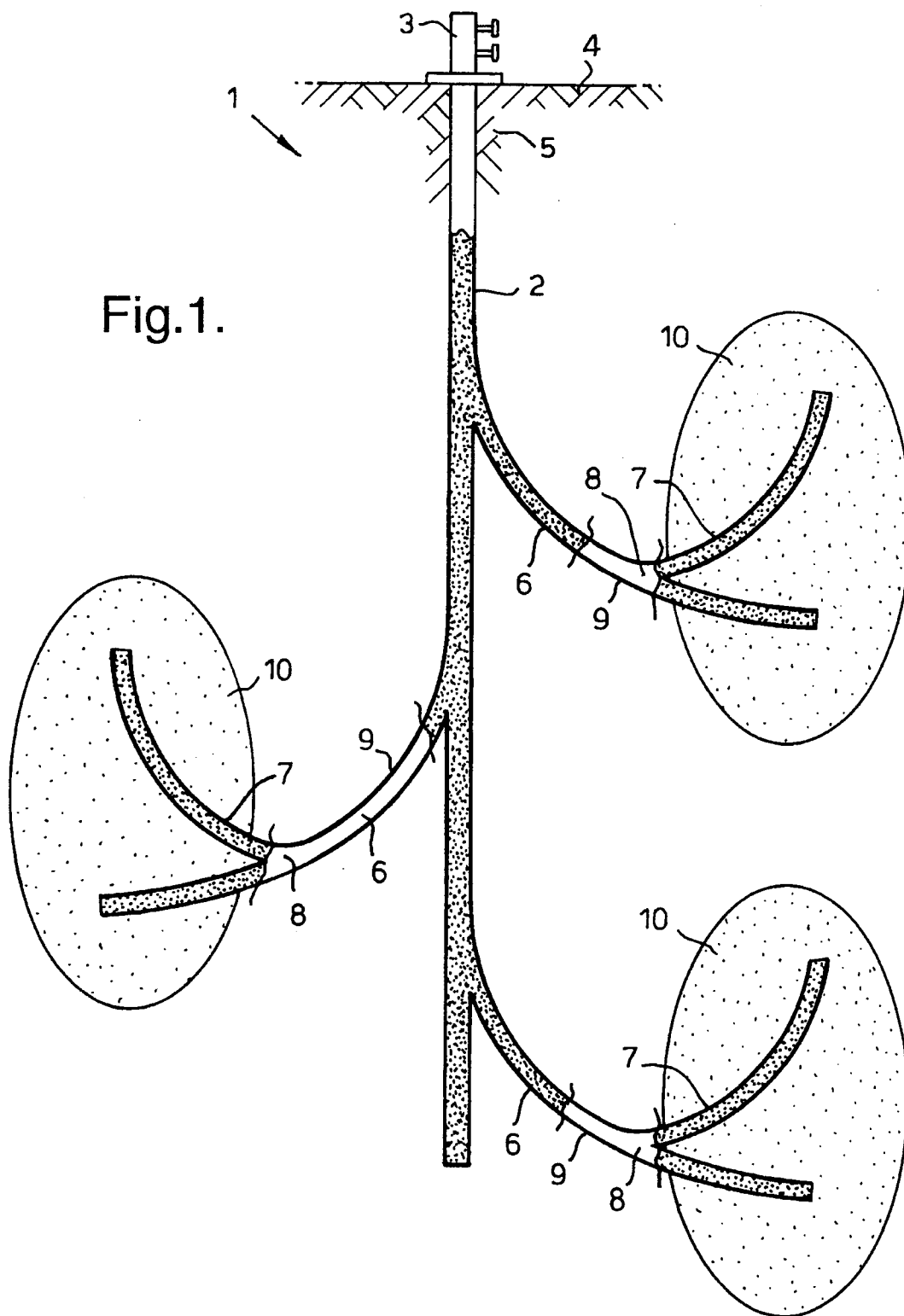
15 9. A well system comprising at least one primary sidetrack and at least one secondary sidetrack wherein the primary sidetrack comprises an expanded expandable liner which comprises an opening into which a secondary sidetrack debouches.

20 10. The well system of claim 9, wherein the expanded liner in the primary sidetrack has an internal width which is substantially equal to the internal width of a casing in the primary wellbore.

25 11. The well system of claim 10, wherein one or more tertiary sidetracks debouch into at least one secondary sidetrack so that a root-like multilateral well system is created.

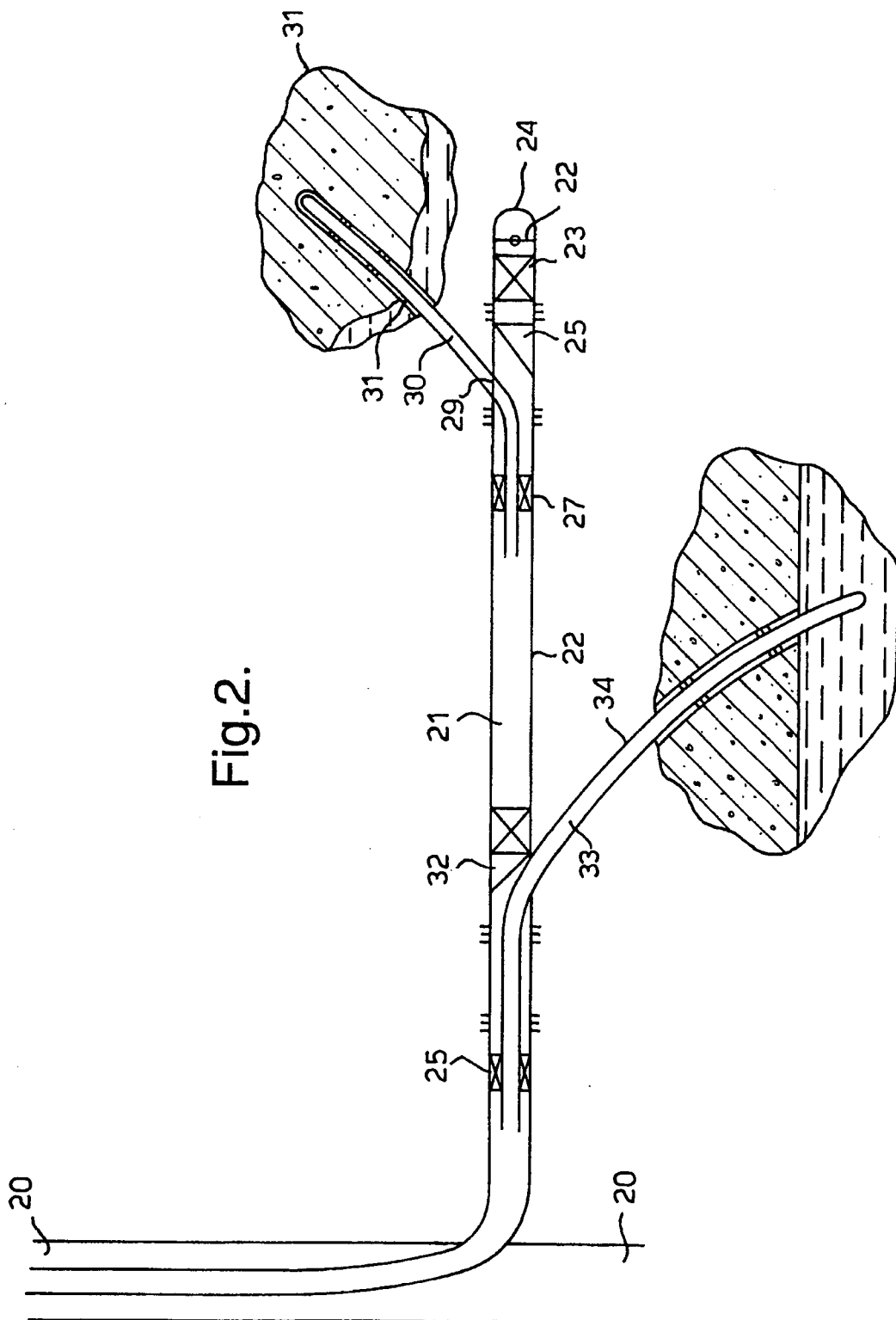
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Fig.1.



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Fig.2.



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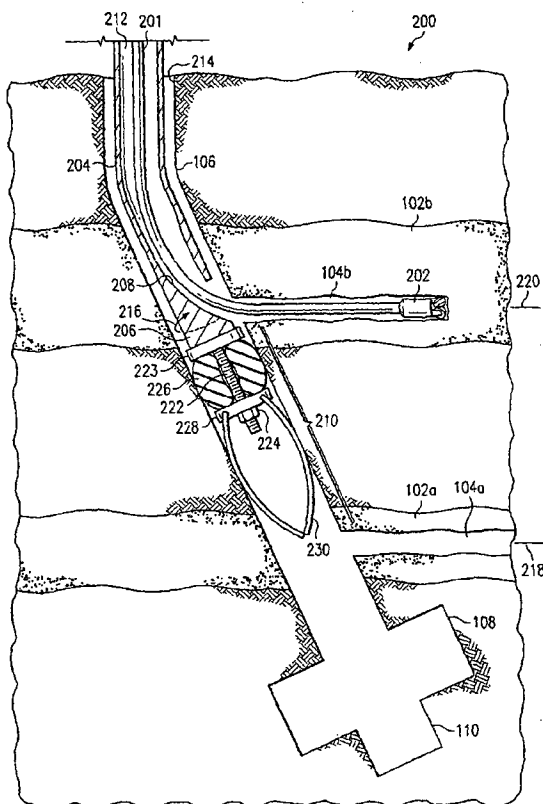
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[Continued on next page]

(54) Title: WELLBORE SEALING SYSTEM AND METHOD



(57) Abstract: In accordance with one embodiment of the present invention, a method for drilling wellbores includes drilling a main wellbore and disposing a casing string in the main wellbore. The casing string has a deflecting member and a sealing member coupled thereto. The method further includes disposing a drill string having a drill bit coupled at a lower end thereof in the casing string and drilling, from the main wellbore, a first lateral wellbore at a first depth with the drill bit. The method further includes removing the drill bit from the first lateral wellbore, transferring the casing string and the drill bit to a second depth that is higher than the first depth, drilling, from the main wellbore, a second lateral wellbore at the second depth with the drill bit, and preventing, using the sealing member, a fluid from the first lateral wellbore from flowing above approximately the second depth while drilling the second lateral wellbore.

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WELLBORE SEALING SYSTEM AND METHOD

TECHNICAL FIELD OF THE INVENTION

The present invention relates generally to systems and methods for the recovery of subterranean resources and, more particularly, to a wellbore sealing system and method.

BACKGROUND OF THE INVENTION

Subterranean deposits of coal (typically referred to as "coal seams") often contain substantial quantities of entrained methane gas. Limited production and use of methane gas from coal seams has occurred for many years because substantial obstacles have frustrated extensive development and use of methane gas deposits in coal seams.

In recent years, various methods have been used to retrieve methane gas deposits from coal seams. One such method is the use of underbalanced drilling using a dual-string technique. As an example of this method, a fluid such as drilling fluid is circulated down a drill string, while another relatively light fluid such as air or nitrogen is circulated down an annulus formed between an outside surface of a drill string and an inside surface of a casing string. A mixture of these fluids is retrieved from an annulus formed between an outer surface of the casing string and an inside surface of the wellbore after mixing with a gas or other fluid obtained from a lateral wellbore being drilled. The purpose of the lighter fluid is to lighten the weight of the drilling fluid such that the hydrostatic head of the

drilling fluid does not force the drilling fluid into the subterranean formation and create detrimental effects.

SUMMARY OF THE INVENTION

5 The present invention provides a wellbore sealing system and method that substantially eliminates or reduces the disadvantages and problems associated with previous systems and methods.

10 In accordance with one embodiment of the present invention, a method for drilling wellbores includes drilling a main wellbore and disposing a casing string in the main wellbore. The casing string has a deflecting member and a sealing member coupled thereto. The method further includes disposing a drill string having a drill bit coupled at a lower end thereof in the casing string and drilling, from the main wellbore, a first lateral wellbore at a first depth with the drill bit. The method further includes removing the drill bit from the first lateral wellbore, transferring the casing string and the drill bit to a second depth that is higher than the first depth, drilling, from the main wellbore, a second lateral wellbore at the second depth with the drill bit, and preventing, using the sealing member, a fluid from the first lateral wellbore from flowing above approximately the second depth while drilling the second lateral wellbore.

25 According to another embodiment of the present invention, a system for drilling wellbores includes a casing string, a deflecting member coupled to the casing string, and a sealing member coupled to the deflecting member. The sealing member is adapted to seal a wellbore into which the casing string is inserted such that a

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fluid existing in the wellbore below the sealing member is prevented from flowing upward past the sealing member.

Some embodiments of the present invention may provide one or more technical advantages. These technical advantages may include more efficient drilling and production of methane gas and greater reduction in costs and problems associated with other drilling systems and methods. For example, there may be less damage to lateral wellbores because of mud or other fluids entering a lateral wellbore from the drilling of another lateral wellbore. In addition, cuttings are prevented from dropping into lower lateral wellbores while an upper lateral wellbore is being drilled. Another technical advantage includes providing a method for killing a lateral wellbore, while still being able to drill another lateral wellbore. An additional technical advantage is that underbalanced drilling may be performed along with the teachings of one embodiment of the present invention.

Other technical advantages of the present invention are readily apparent to one skilled in the art from the figures, descriptions, and claims included herein.

BRIEF DESCRIPTION OF THE DRAWINGS

For a more complete understanding of the present invention and its advantages, reference is now made to the following description taken in conjunction with the accompanying drawings, wherein like numerals represent like parts, in which:

FIGURE 1 is a cross-sectional view illustrating an example slant well system for production of resources

from one or more subterranean zones via one or more lateral wellbores;

FIGURE 2 illustrates an example system for drilling lateral wellbores according to one embodiment of the present invention;

FIGURE 3 illustrates an example system for drilling lateral wellbores according to another embodiment of the present invention; and

FIGURE 4 is a flowchart demonstrating an example method for drilling lateral wellbores according to one embodiment of the present invention.

DETAILED DESCRIPTION OF THE INVENTION

Embodiments of the present invention and their advantages are best understood by referring now to FIGURES 1 through 4 of the drawings, in which like numerals refer to like parts.

FIGURE 1 is a cross-sectional view illustrating an example well system 100 for production of resources from one or more subterranean zones 102 via one or more lateral wellbores 104. In various embodiments described herein, subterranean zone 102 is a coal seam; however, other subterranean formations may be similarly accessed using well system 100 of the present invention to remove and/or produce water, gas, or other fluids. System 100 may also be used for other suitable operations, such as to treat minerals in subterranean zone 102 prior to mining operations, or to inject or introduce fluids, gasses, or other substances into subterranean zone 102.

Referring to FIGURE 1, well system 100 includes an entry wellbore 105, two main wellbores 106, a plurality of lateral wellbores 104, a cavity 108 associated with

each main wellbore 106, and a rat hole 110 associated with each main wellbore 106. Entry wellbore 105 extends from a surface 12 towards subterranean zones 102. Entry wellbore 105 is illustrated in FIGURE 1 as being substantially vertical; however, entry wellbore 105 may be formed at any suitable angle relative to surface 12 to accommodate, for example, surface 12 geometries and/or subterranean zone 102 geometries.

Main wellbores 106 extend from the terminus of entry wellbore 105 toward subterranean zones 102, although main wellbores may alternatively extend from any other suitable portion of entry wellbore 105. Where there are multiple subterranean zones 102 at varying depths, as illustrated in FIGURE 1, main wellbores 106 extend through the subterranean zones 102 closest to surface 12 into and through the deepest subterranean zones 102. There may be one or any number of main wellbores 106. As illustrated, main wellbores 106 are slant wells and, as such, are formed to angle away from entry wellbore 105 at an angle designated α , which may be any suitable angle to accommodate surface topologies and other factors similar to those affecting entry wellbore 105. Main wellbores 106 are formed in relation to each other at an angular separation of β degrees, which may be any suitable angle, such as 60 degrees. However, main wellbores 106 may be separated by other angles depending likewise on the topology and geography of the area and location of a targeted subterranean zone 102. Main wellbores 106 may also include cavity 108 and/or rat hole 110 located at a terminus of each wellbore 106. Main wellbore 106 may

include one, both, or neither cavity 108 and rat hole 110.

Lateral wellbores 104 extend from each main wellbore 106 into an associated subterranean zone 102. Lateral wellbores 104 are shown in FIGURE 1 to be substantially horizontal; however, lateral wellbores 104 may be formed in other suitable directions off of main wellbores 106 and may have a curvature associated therewith. Any suitable systems and/or methods may be used to drill lateral wellbores 104; however, a particular system for drilling lateral wellbores 104 according to one embodiment of the present invention is described below in conjunction with FIGURES 2 through 4.

FIGURE 2 illustrates an example system 200 for drilling lateral wellbores 104 according to one embodiment of the present invention. As illustrated, system 200 includes a drill string 201 having a drill bit 202, a casing string 204, a deflecting member 206 having a deflecting surface 208 coupled to a lower end of casing string 204, and a sealing member 210 coupled to a lower end of deflecting member 206.

Drill string 201 may be any suitable drill string having any suitable length and diameter and any suitable drill bit 202 for the purpose of drilling lateral wellbores 104. Drill string 201 is typically a hollow conduit for allowing drilling fluids to flow therethrough. Drill bit 202 may be driven through the use of any suitable motor powered by the drilling fluid and may have any suitable configuration. To direct drill string 201 and drill bit 202 for the purpose of drilling lateral wellbore 104, deflecting surface 208 of deflecting member 206 is utilized.

Casing string 204 may be any suitable casing string having any suitable diameter that is to be inserted into main wellbore 106. Casing string 204 is adapted to rotate within main wellbore 106 as illustrated by arrow 216. An inner annulus 212 is formed between the inner surface of casing string 204 and the outer surface of drill string 201. An outer annulus 214 is also formed between an outside surface of casing string 204 and the surface of main wellbore 106. Inner annulus 212, outer annulus 214, and drill string 201 may be used to perform underbalanced drilling. As one example of underbalanced drilling, a first fluid may be circulated down drill string 201, such as drilling mud or other suitable drilling fluids. A second fluid is circulated down inner annulus 212, such as air, nitrogen, or other relatively light fluid. Both first and second fluids may be retrieved from outer annulus 214 after mixing with a gas or other fluid produced from lateral wellbore 104. The purpose of the second fluid is to lighten the weight of the first fluid such that the hydrostatic head of the first fluid does not force first fluid into the subterranean formation. As a variation, the second fluid may be circulated down outer annulus 214 and the mixture of the first and second fluids along with the gas from lateral wellbore 104 may be retrieved via inner annulus 212.

According to the teachings of the present invention, sealing member 210 is adapted to seal main wellbore 106 such that a fluid existing in main wellbore 106 below sealing member 210 is prevented from flowing upward past sealing member 210. In one embodiment of the invention, this allows the drilling of a lateral wellbore 104a in a

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subterranean zone 102a at a first depth 218 and then the drilling of a lateral wellbore 104b in a subterranean zone 102b at a second depth 220, while ensuring that any gas or other fluid obtained from lateral wellbore 104a at first depth 218 does not flow past sealing member 210 and interfere with the drilling of lateral wellbore 104b in subterranean zone 102b at second depth 220. In addition, any cuttings resulting from the drilling of lateral wellbore 104b are prevented from dropping into lateral wellbore 104a. An example sealing member 210 is illustrated in FIGURE 2.

As illustrated in FIGURE 2, example sealing member 210 includes a bolt 222, a nut 224, a plug 226, a washer 228, and a resilient member 230. Bolt 222 is coupled to a lower end 223 of deflecting member 206 in any suitable manner. Nut 224 is threaded on bolt 222, while washer 228 surrounds bolt 222 and is rigidly coupled to nut 224. Plug 226 surrounds bolt 222 and is disposed between washer 228 and lower end 223 of deflecting member 206.

Plug 226 is formed from any suitable material, such as an elastomer, resilient enough to be circumferentially expanded or circumferentially retracted but stiff enough to be able to prevent any gas or other fluid existing in main wellbore 106 below sealing member 210 to leak past plug 226. The circumferential expansion or retraction of plug 226 via the rotation of casing string 204 is described in more detail below. In other embodiments, plug 226 is an air-filled diaphragm formed from any suitable material.

Resilient member 230 is coupled to washer 228 in any suitable manner. Resilient member 230, which may be any suitable resilient member, such as a bow spring, is

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adapted to engage the wall of main wellbore 106 and apply enough force to the wall of main wellbore 106 to prevent nut 224 and washer 228 from turning while casing string 204 is rotated within main wellbore 106. Washer 228 and nut 224 are fixed to one another such that, when casing string 204 is rotated, nut 224 and washer 228 do not rotate. In this way, bolt 222 may longitudinally compress plug 226 to circumferentially expand plug 226 so that it may press against the wall of main wellbore 106 to prevent gas or other fluid from flowing upward past plug 226. Conversely, when casing string 204 is rotated in an opposite direction, then bolt 222 acts to longitudinally decompress plug 226, thereby circumferentially retracting plug 226 so that gas or other fluid may bypass plug 226.

In operation of one embodiment of system 200 of FIGURE 2, main wellbore 106 is drilled via any suitable method. Casing string 204 having deflecting member 206 and sealing member 210 attached thereto is inserted into main wellbore 106. While lowering casing string 204 down main wellbore 106, plug 226 is in a circumferentially retracted position so that any air or other fluid existing at a depth below sealing member 210 may leak past plug 226. Once at a desired depth, such as first depth 218, drill string 201 is inserted within casing string 204 so that lateral wellbore 104a may be drilled at first depth 218. After drilling lateral wellbore 104a drill string 201 is retracted from lateral wellbore 104a. At this time, casing string 204 is rotated in a desired direction so that plug 226 may be longitudinally compressed and circumferentially expanded to press against the wall of main wellbore 106. As described

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above, this prevents any gas or other fluid produced from lateral wellbore 104a from traveling up past plug 226. Casing string 204 may then be raised to second depth 220 so that lateral wellbore 104b may be drilled. Lateral
5 wellbore 104b may then be drilled with drill bit 202 with the assurance that sealing member 210 will prevent any gas or fluid from passing upward and causing detrimental effects. Other lateral wellbores 104 may be drilled
10 successively at shallower depths according to a similar procedure. Many different types of sealing members 210 are contemplated by the present invention. Another example sealing member is shown below in conjunction with FIGURE 3.

FIGURE 3 illustrates another example sealing member
15 310. In one embodiment, sealing member 310 is a resilient plunger 300 formed from a suitable elastomer; however, other suitable resilient materials may be utilized. As illustrated, plunger 300 includes a
20 plurality of ridges 302 that have an inherent stiffness to prevent gas or other fluid from a depth in main wellbore 106 below plunger 300 from leaking past plunger 300 to a higher depth (or vice versa) while a lateral wellbore 104 is being drilled. In addition, plunger 300,
25 via ridges 302, possesses enough resiliency to allow gas or other fluid existing at a depth below plunger 300 to flow past plunger 300 to relieve any potential increasing pressure below plunger 300 when plunger 300 is inserted into main wellbore 106. Plunger 300 may have other
30 suitable configurations and may be coupled to deflecting member 206 in any suitable manner. In other embodiments, plunger 300 is a hollow plunger having any suitable fluid therein.

Plunger 300 may also include a relief valve (not shown) that is operable to allow gas or other fluid at a depth below plunger 300 to flow to a depth above plunger 300 when a predetermined pressure is reached. Any
5 suitable relief valve may be utilized and the relief valve may be coupled to plunger 300 in any suitable manner. The relief valve may be set to open or close at a predetermined pressure depending on the pressure expected to be encountered in main wellbore 106 below
10 sealing member 310. A relief valve may also be utilized with sealing member 210 of FIGURE 2 in a similar manner.

FIGURE 4 is a flow chart demonstrating an example method of drilling lateral wellbores 104 according to one embodiment of the present invention. The method begins
15 at step 400 where main wellbore 106 is drilled. Casing string 204 having deflecting member 206 at a lower end thereof is disposed in main wellbore 106 at step 402. Deflecting member 206 has any suitable sealing member coupled at a lower end thereof. Although example sealing
20 members 210 and 310 are described above, any suitable sealing member may be used within the scope of the present invention.

As described above, the sealing member prevents a gas or other fluid from a lower lateral wellbore from
25 flowing up to a higher lateral wellbore at a higher depth while drill string 201 is drilling the higher lateral wellbore. At step 404, drill string 201 having drill bit 202 is disposed in casing string 204. At step 406, a first lateral wellbore 104a is drilled from main wellbore
30 106 at first depth 218. Deflecting surface 208 of deflecting member 206 is utilized to direct drill string 201 in the desired drilling direction.

After first lateral wellbore 104a is drilled, drill bit 202 is removed from first lateral wellbore 104a at step 408. At step 410, casing string 204 and drill bit 202 are transferred to second depth 220 that is less than first depth 218. Any gas or other fluid produced from first lateral wellbore 104a is prevented, as denoted by step 412, from flowing up to second depth 220 by the sealing member. At step 414, second lateral wellbore 104b is drilled from main wellbore 106 at second depth 220 with drill bit 202. Successive lateral wellbores 104 may be drilled at successively higher depths per the above method. In lieu of a slant well system, the described example method may be used with other suitable well systems.

Although the present invention is described with several embodiments, various changes and modifications may be suggested to one skilled in the art. The present invention intends to encompass such changes and modifications as they fall within the scope of the appended claims.

WHAT IS CLAIMED IS:

1. A method for drilling wellbores, comprising:

drilling a main wellbore;

5 disposing a casing string in the main wellbore, the casing string having a deflecting member and a sealing member coupled thereto;

disposing a drill string having a drill bit coupled at a lower end thereof in the casing string;

10 drilling, from the main wellbore, a first lateral wellbore at a first depth with the drill bit;

removing the drill bit from the first lateral wellbore;

transferring the casing string and the drill bit to a second depth that is higher than the first depth;

15 drilling, from the main wellbore, a second lateral wellbore at the second depth with the drill bit; and

preventing, using the sealing member, a fluid from the first lateral wellbore from flowing above approximately the second depth while drilling the second lateral wellbore.

20

2. The method of Claim 1, further comprising:

removing the drill bit from the second lateral wellbore;

25 transferring the casing string and the drill bit to a third depth that is higher than the second depth;

drilling, from the main wellbore, a third lateral wellbore at the third depth with the drill bit; and

30 preventing, using the sealing member, the gas from flowing above approximately the third depth while drilling the third lateral wellbore.

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3. The method of Claim 1, wherein drilling the main wellbore comprises drilling a slant wellbore.

5 4. The method of Claim 1, further comprising disposing the casing string in the main wellbore such that an outer annulus is formed between a wall of the main wellbore and an outer wall of the casing string, and disposing the drill string in the casing string such that an inner annulus is formed between an inner wall of the casing string and an outer wall of the drill string.

10

5. The method of Claim 4, further comprising:
circulating a first fluid down an inner passage of the drill string;

15 circulating a second fluid down the inner annulus;
regulating an amount of the second fluid to prevent the first fluid from entering a subterranean formation in which the lateral wellbore is being drilled; and

20 retrieving a mixture of the first and second fluids and the gas from the lateral wellbore through the outer annulus.

6. The method of Claim 4, further comprising:
circulating a first fluid down an inner passage of the drill string;

25 circulating a second fluid down the outer annulus;
regulating an amount of the second fluid to prevent the first fluid from entering a subterranean formation in which the lateral wellbore is being drilled; and

30 retrieving a mixture of the first and second fluids and the gas from the lateral wellbore through the inner annulus.

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7. The method of Claim 1, wherein disposing the casing string in the main wellbore comprises lowering the casing string down the main wellbore while allowing a fluid in the main wellbore below the sealing member to flow past the sealing member.

8. The method of Claim 1, wherein preventing the gas from the first lateral wellbore from flowing above approximately the second depth while drilling the second lateral wellbore comprises longitudinally compressing a plug of the sealing member to circumferentially expand the plug such that an outer surface of the plug engages a wall of the main wellbore.

9. The method of Claim 8, further comprising rotating the casing string to longitudinally compress the plug.

10. The method of Claim 1, wherein preventing the gas from the first lateral wellbore from flowing above approximately the second depth while drilling the second lateral wellbore comprises utilizing a resilient plunger as the sealing member.

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11. A system for drilling wellbores, comprising:
a casing string;
a deflecting member coupled to the casing string;
and

5 a sealing member coupled to the deflecting member,
the sealing member configured to seal a wellbore into
which the casing string is inserted such that a fluid
existing in the wellbore below the sealing member is
prevented from flowing upward past the sealing member.

10 12. The system of Claim 11, wherein the sealing
member comprises a resilient plunger.

15 13. The system of Claim 12, wherein the sealing
member further comprises a relief valve operable to allow
a fluid in the wellbore below the resilient plunger to
flow past the resilient plunger.

20 14. The system of Claim 11, wherein the sealing
member comprises a solid plug.

15. The system of Claim 14, wherein the sealing
member further comprises:

a bolt to support the solid plug;

25 a nut coupled to the bolt;

a washer disposed between the nut and the plug; and

a spring member coupled to the washer, the spring
member adapted to engage a wall of the wellbore to
prevent the washer from rotating when the casing string
is rotated in the wellbore such that the solid plug is
30 longitudinally compressed and circumferentially expanded
to engage the wall of the wellbore.

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16. The system of Claim 11, wherein the sealing member comprises an air-filled diaphragm.

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17. A sealing member, comprising:

a resilient plunger adapted to couple to an end of a casing string and operable to prevent a gas within a wellbore from flowing from a lower depth below the resilient plunger to a higher depth above the resilient plunger while a lateral wellbore is being drilled.

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18. A sealing member, comprising:

a bolt adapted to couple to an end of a casing string;

a nut rotatably coupled to the bolt;

5 a washer engaged with the nut;

a plug surrounding the bolt and resting against the washer;

10 a spring member coupled to the washer, the spring member adapted to engage a wall of a wellbore to prevent the washer from rotating when the casing string is rotated in the wellbore such that the plug is longitudinally compressed and circumferentially expanded to engage the wall of the wellbore to prevent a gas within the wellbore from flowing from a lower depth below the plug to a higher depth above the plug while a lateral wellbore is being drilled.

15 19. The sealing member of Claim 18, wherein the spring member is adapted to engage the wall of the wellbore to prevent the washer from rotating when the casing string is rotated in the wellbore such that the plug is longitudinally expanded and circumferentially retracted to allow a gas within the wellbore from flowing from a lower depth below the plug to a higher depth above the plug.

20 20. The sealing member of Claim 18, wherein the plug comprises an air-filled diaphragm.

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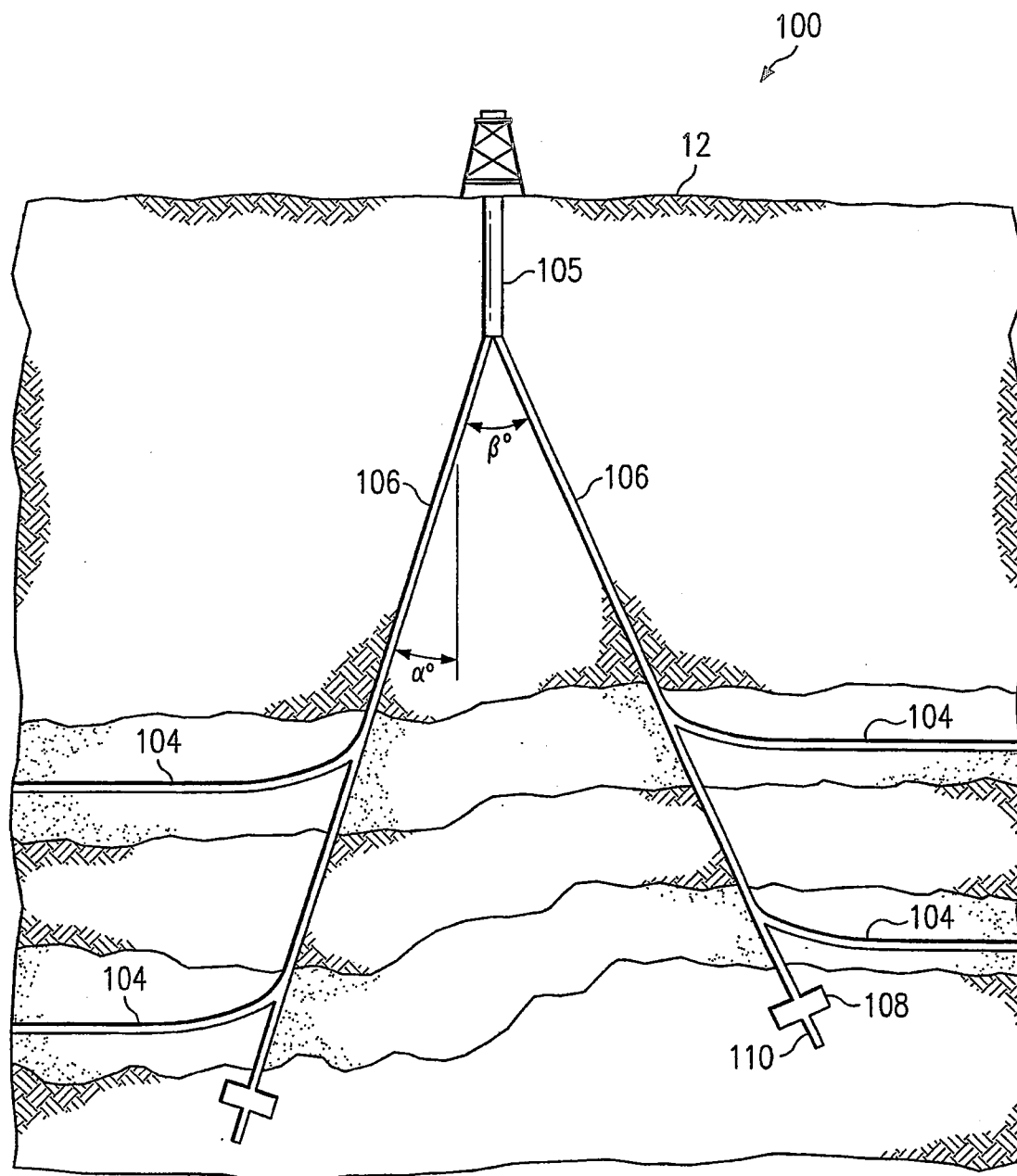


FIG. 1

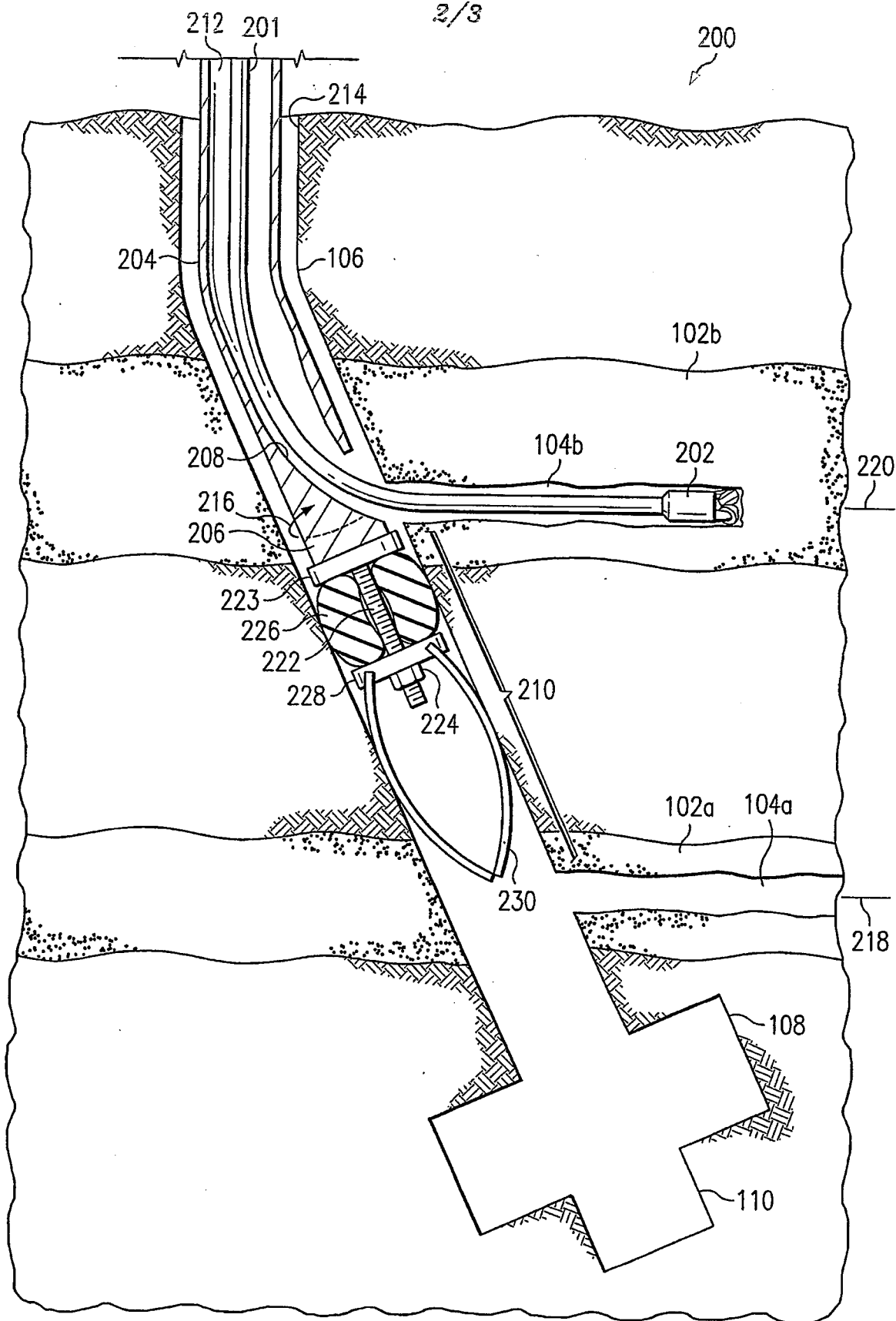
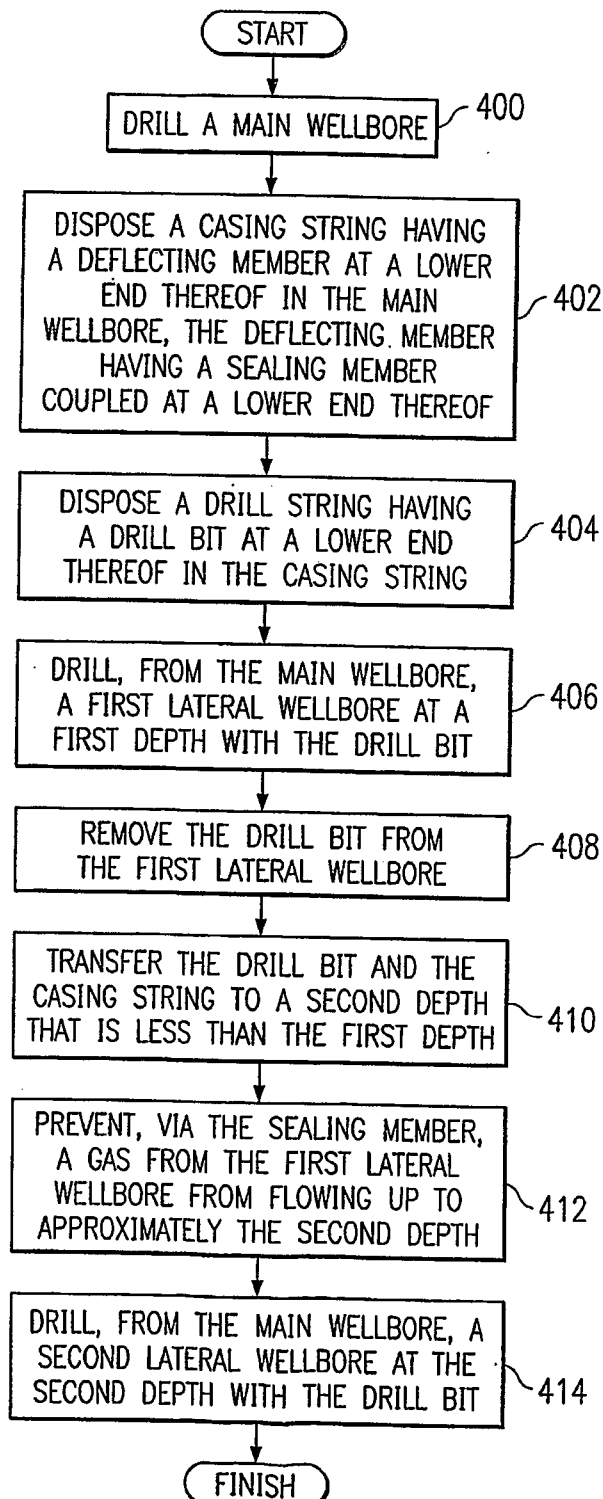


FIG. 2

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FIG. 4



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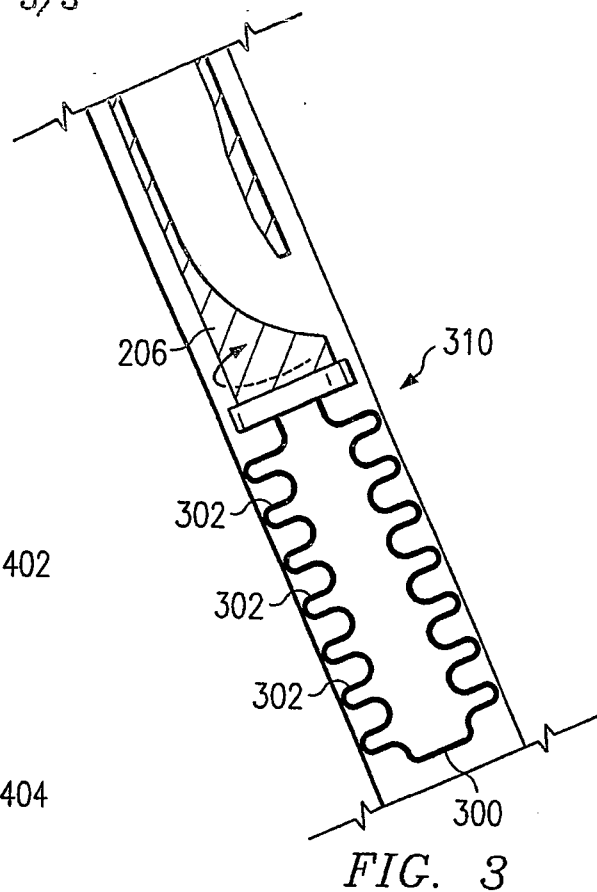


Fig.1.

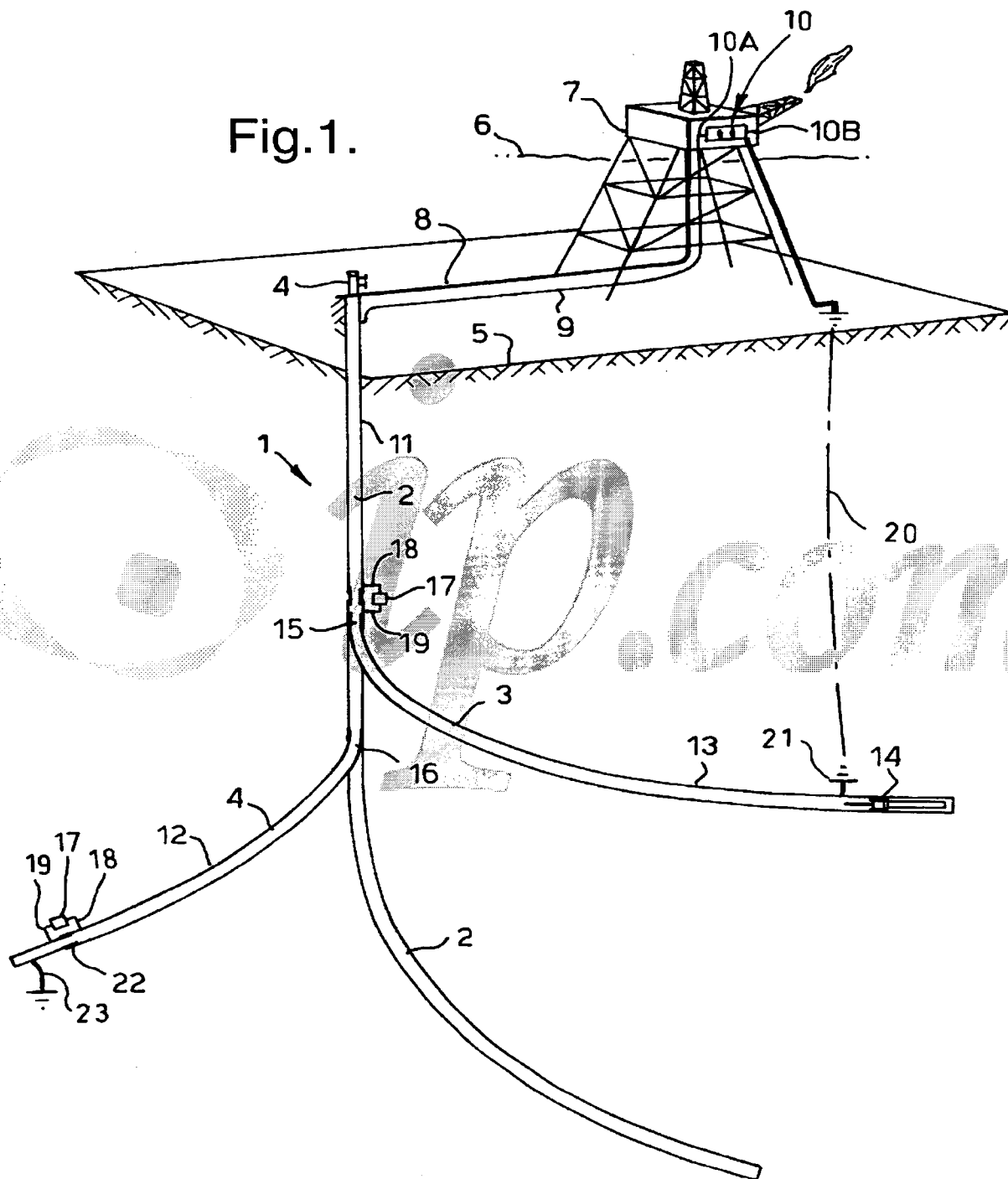


Fig.2.

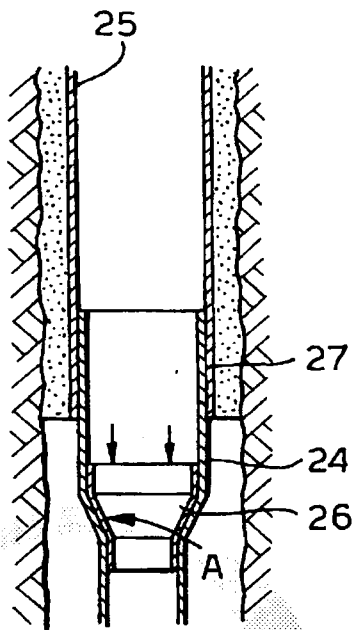


Fig.3.

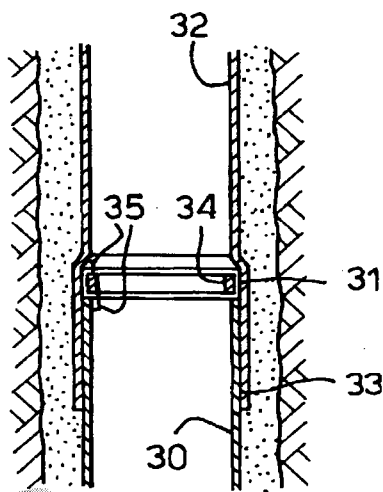


Fig.4.

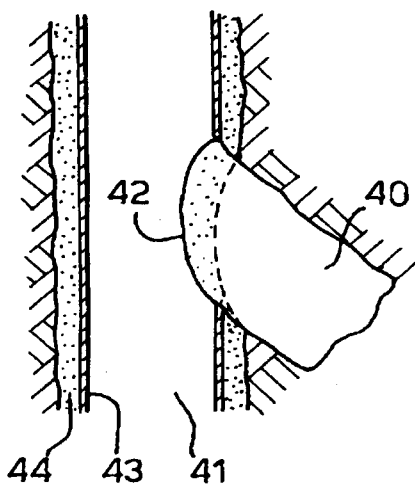


Fig.5.

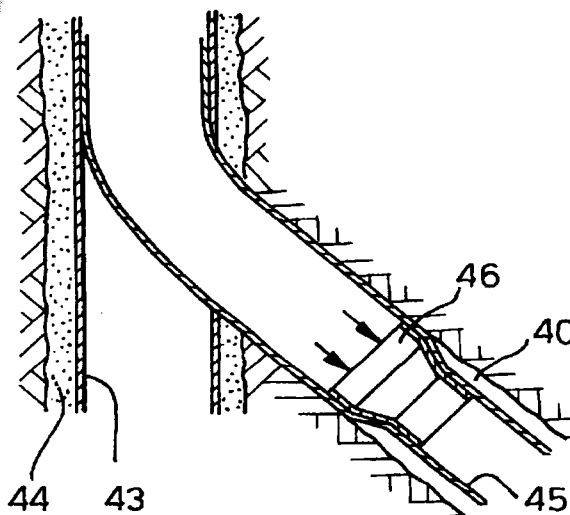


Fig.6.

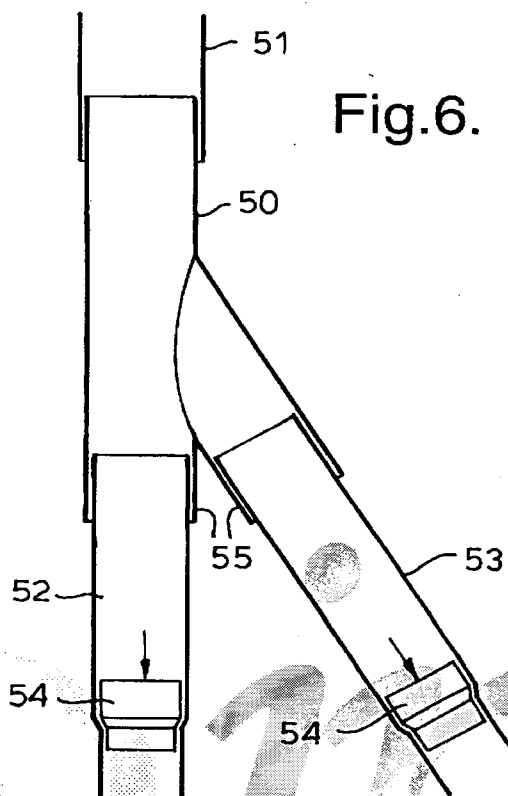


Fig.7.

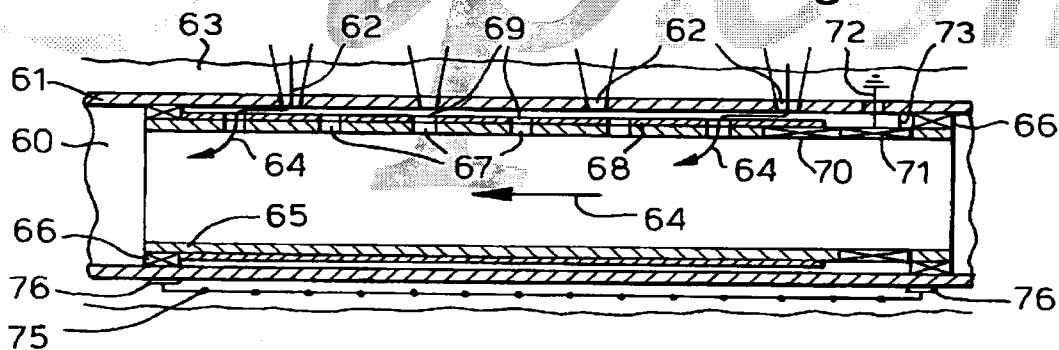
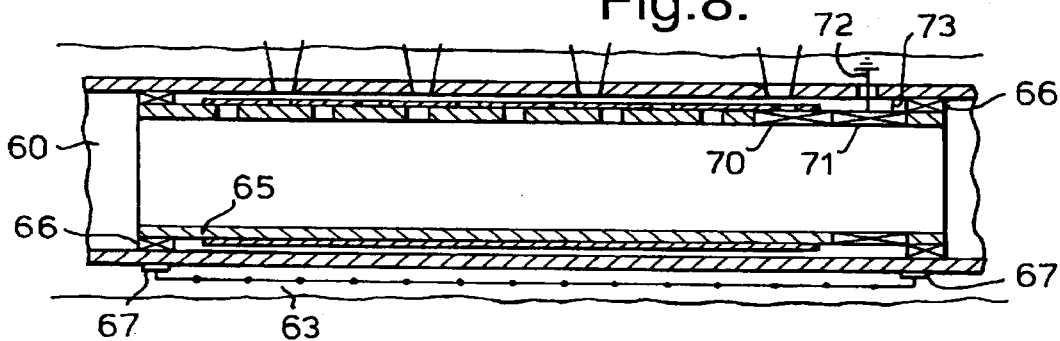


Fig.8.



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MULTILATERAL WELL AND ELECTRICAL TRANSMISSION SYSTEM

FIELD OF THE INVENTION

The invention relates to a multilateral well and electrical transmission system.

BACKGROUND OF THE INVENTION

Numerous electrical and non-electrical power and communication systems are known for use in unbranched or multilateral oil and/or gas production wells.

U.S. Pat. Nos. 5,706,892; 5,706,896 and 5,721,538 disclose that a multilateral well may be equipped with a hardwired electrical or with a wireless communication system and that such a wireless system preferably transmits acoustic waves through a string of well tubulars such as the production tubing. Disadvantages of the known system are that installation of a wire tree in a multilateral well is a complex and expensive operation and that a wireless acoustic transmission system will suffer from high transmission losses and background noise. These disadvantages are particularly significant if the well is equipped with an expandable casing and/or production tubing. Around such an expanded well tubular there is hardly any or no annular space left for housing of the electrical cables and as a result of the physical contact between the expanded tubular and the surrounding formation acoustic signals will be dampened to a high extent.

Numerous other hardwired or wireless power transmission and communication systems are known, which have in common that they require complex and expensive equipment and that they are not suitable for use in multilateral wells.

U.S. Pat. No. 4,839,644 and European patent No. 295178 disclose a wireless communication system known as "Tuc-atran" which generates antenna currents in an unbranched well where the production tubing and surrounding well casing are electrically insulated from each other. The requirement of electrical insulation between the tubing and the casing is often difficult to accomplish in e.g. curved borehole sections and areas where brine is present in the tubing/casing annulus. International patent application WO80/00727 discloses another signal transmission system which utilizes an electrical circuit formed by a production tubing and a surrounding well casing.

U.S. Pat. No. 4,484,627, UK patent application No. 2322740 and International patent applications Nos. PCT/GB79/00158; PCT/GB93/01272 and PCT/EP96/00083 disclose other downhole electric transmission systems which utilize an externally insulated tubing in an unbranched well.

The present invention aims to overcome the disadvantages of the known transmission systems and to provide a downhole power and/or signal transmission system which can be used to transmit electrical power and/or signals throughout a multilateral well system in a safe and reliable manner even if the well comprises expandable well tubulars and without requiring complex wire trees or production tubing that are electrically insulated from the surrounding well casings.

SUMMARY OF THE INVENTION

In accordance with the invention there is provided a multilateral well and electric transmission system, which comprises a primary wellbore in which a primary well tubular is arranged and a branch wellbore in which a branch

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well tubular is arranged, wherein the branch well tubular is connected in an electrically conductive manner to the primary well tubular such that the primary and branch well tubulars form a link for transmission of electrical power and/or signals between the primary and branch wellbore.

Preferably, the primary and branch well tubulars form a link for transmitting low voltage power from a first pole of an electrical power source, which is electrically connected to the primary well tubular, to electrically powered equipment within the branch wellbore which is electrically connected to the branch well tubular. An electrical circuit is created by electrically connecting a second pole of the electrical power source and the branch well tubular(s) to the earth. It is also preferred that said equipment comprises a re-chargeable battery which is trickle-charged by the low voltage electrical power transmitted via the well tubulars.

Suitably low voltage power is transmitted as a direct current (DC) having a voltage of less than 100 V, preferably less than 50 V through the casing or production tubing of the primary well, which is imperfectly insulated to the surrounding earth formation by a surrounding cement or other sealing material, such as an addition curing silicone composition.

At the same time pulsed electromagnetic signals are transmitted which involve changes of voltage level oscillating around the DC voltage level of the well tubular at very low frequency (VLF), between 3 and 20 kHz, or preferably at extremely low frequency (ELF), between 3 and 300 Hz.

The surface power generator and the downhole equipment or battery may have an electrode which is connected to the earth so that an imperfect electric loop exists between the power generator and the downhole equipment or battery.

It is also preferred that the branch well tubular is a radially expandable tubular which is made of an electrically conductive material and which is radially expanded within the branch well during installation and wherein an electrically conductive receptacle is arranged at or near the branchpoint such that the expanded branch well tubular is pressed into electrical contact with the receptacle as a result of the expansion process.

A particular advantage of the use of expandable tubulars at least in the branch wellbore is that as a result of the radial expansion process a surplus expansion is created in the expanded tubular which will ensure an intimate electrical contact between adjacent well tubulars of which the ends coaxially overlap each other. Such an intimate electrical contact is also made at the branchpoint between the expanded branch well tubular and the receptacle which may be formed by the primary well tubular itself or by a branched bifurcation element.

Suitably the primary and branch well tubulars are made of a formable steel grade and the branch well tubular is expanded during installation such that the expanded branch well tubular has an inner diameter which is at least 0.9 times the inner diameter of the primary well tubular, so that a substantially monobore multilateral well system is created which may have any desired amount of branches and sub-branches.

Preferably the electrically powered downhole well equipment comprises measuring and/or control equipment which is powered by a rechargeable lithium-ion high-temperature or other battery and/or a supercapacitor and/or a downhole energy conversion system such as a piezo-electrical system, turbine or downhole fuel cell and is mounted on an equipment carrier module in the form of a sleeve which is removably secured within the branch well tubular such that one electrode of the battery is electrically connected to the

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branch well tubular and another electrode of the battery is electrically connected to the subsurface earth formation surrounding the branch wellbore.

Suitably the sleeve spans an inflow area of the branch wellbore where the branch well tubular is perforated, the expandable clamps consist of a pair of expandable packers which seal off an annular space between the branch well tubular and sleeve near each end of the sleeve and wherein the sleeve is provided with one or more fluid inlet ports which can be opened and closed by one or more valves which are powered by the rechargeable battery. The triggering can be done via a downhole or surface actuated control system.

In many lengthy multilateral well systems it is also preferred that at least one of the primary and branch well tubulars is equipped with at least one electrical booster station which station spans an electrically non-conductive section of the well tubular and which station is electrically connected to the electrically conductive parts of the well tubular at both sides of the electrically non-conductive section thereof.

The electrical booster stations may be distributed at regular intervals along the length of the primary and branch wellbores. If an electrical booster station is required at a location where the ends of two adjacent expanded well tubulars co-axially overlap each other, an electrical sealing material may be arranged between the overlapping tubular sections and the booster may be installed as a sleeve within the outermost tubular adjacent to the innermost tubular such that one electrode of the booster station is electrically connected to the innermost and another electrode thereof is connected to the outermost tubular.

It is observed that in some instances the booster station may be installed at a well junction, in which case the electrodes of the booster station will make the electric connection between the primary and branch well tubulars.

It is also observed that when used in specification and the appended claims the term multilateral well system refers to a well system having a primary or mother wellbore which extends from a wellhead down into a surface earth formation and at least one branch wellbore which intersects the primary or mother wellbore at a subsurface location.

BRIEF DESCRIPTION OF THE DRAWINGS

Preferred embodiments of the system according to the invention will be described with reference to the accompanying drawings, in which

FIG. 1 is a schematic three-dimensional view of a multilateral well system according to the invention;

FIG. 2 shows how a well tubular is expanded using a conical expansion mandrel;

FIG. 3 shows a connection between two well tubulars where an electrical booster station is arranged;

FIG. 4 shows a branchpoint where a branch wellbore has been drilled through a window in the primary well casing;

FIG. 5 shows how an expandable well liner is expanded in the branch wellbore and electrically connected to the primary well casing;

FIG. 6 shows a branchpoint where the branch well casing and the primary casing underneath the branchpoint are expanded within a bifurcation element or splitter;

FIG. 7 shows a tubular equipment carrier sleeve in the open mode such that oil and/or gas flows via perforations in the sleeve into the wellbore; and

FIG. 8 shows the sleeve of FIG. 7 in the closed mode in which the perforations have been closed off.

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DETAILED DESCRIPTION OF PREFERRED EMBODIMENTS

Referring to FIG. 1 there is shown a multilateral well and electric transmission system 1, which comprises a primary wellbore 2 and two branch wellbores 3 and 4.

The system 1 extends from an underwater wellhead 4 into the bottom 5 of a body of water 6. Oil and/or gas processing equipment on an offshore platform 7 is connected to the wellhead 47 via an underwater flowline 8 and a power supply cable 9 extends from a first pole 10A of an electrical power generator 10 at the platform 7 to primary well casing 11 which has been expanded against the wall of the primary wellbore 2 such that a thin annular layer (not shown) of cement or another sealing material such as an addition curing silicone formulation is present between the expanded casing 11 and borehole wall.

In the lower branch wellbore 4 a branch well liner 12 has been expanded and cemented in place, whereas in the upper branch wellbore 3 a branch well liner 13 is being expanded by pumping or pushing an expansion mandrel 14 there-through towards the toe of the well.

As a result of the expansion process a surplus expansion is created in the expanded casing or liner which ensures that the expanded branch well liners 12 and 13 are firmly pressed against the inner wall of the primary well casing 11 at the branchpoints 15 and 16 so that an excellent electrical connection is established between the branch well liners 12 and 13 and the primary well casing 11.

In the primary well casing 11 an electrical booster station 17 is arranged at a location where an electric insulation sleeve is mounted within the casing 11 and the casing has been milled away over a selected distance. The booster station 17 has one electrode 18 which is electrically connected to the casing section above the gap and another electrode 19 which is electrically connected below the gap. Likewise a similar booster station 17 is arranged in the lower branch wellbore 4 and has electrodes 18,19 which are connected to sections of the branch well liner 12 which co-axially overlap but which are electrically insulated from each other by an electric insulation sleeve 22. Instead of using co-axial electrically insulated tubular sections the electrical insulation may be achieved also by using a pre-installed plastic section in the well tubular which plastic section is expanded in the same way as the steel parts of the tubular string.

For the sake of clarity the power booster stations 17 are shown outside the wellbore but in general these stations 17 will be mounted in an annular carrier sleeve within the well tubulars as is illustrated in FIG. 3. FIG. 1 also shows schematically that a second pole 10B of the electrical power generator 10 is connected to earth and that also the branch well liners 12 and 13 are connected to earth at one or more selected locations 21 and 23 so that the earth 5 forms an electrical return link, illustrated by phantom line 20, from the well liners 12 and 13 and said second pole 10B.

FIG. 2 shows how a lower well tubular, which is made of a formable steel grade 24, is expanded inside the lower end of an existing well tubular 25 using an expansion mandrel 26 having a conical ceramic outer surface having a semi top angle A which is 10° and 40°, and preferably between 20° and 30°. The upper well tubular 25 has been cemented within the wellbore 28 and as a result of the expansion process the lower well tubular obtains a surplus expansion so that its inner diameter becomes larger than the outer diameter of the mandrel 26 and the expanded lower tubular 24 is firmly pressed against the overlapping lower part 27 of

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the upper tubular 25 so that a reliable electrical connection is created between the lower and upper well tubulars 24 and 25.

FIG. 3 illustrates a location where a lower tubular 30 has been expanded within a widened lower end 31 of an upper well tubular 32 and an electrical insulation sleeve 33 is arranged between the co-axial tubular parts.

A ring-shaped electrical power booster station 34 is arranged within the widened lower end 31 of the upper tubular 32 just above the top of the lower tubular 30. The station 34 is equipped with electrodes 35 which establish an electrical connection between the tubulars 30 and 32.

FIG. 4 shows how a branch wellbore 40 is drilled away from a primary wellbore 41 through an opening 42 that has been milled in the primary well casing 43 and the surrounding cement annulus 44.

FIG. 5 shows how an expandable branch well liner 45 is expanded in the branch wellbore 40 of FIG. 4 by an expansion mandrel 46 which is similar to the mandrel 26 shown in FIG. 2.

As a result of the surplus expansion during the expansion process the branch well liner 45 is elastically pressed against the inner wall of the primary well casing 43 and to the rims of the opening 42 thereby establishing a firm electrical connection between the primary well casing 43 and the branch well liner 44 which connection remains reliable throughout the lifetime of the well.

FIG. 6 shows a branchpoint in a multilateral well system where a bifurcation element 50 or splitter is secured and electrically connected (optionally via an electric booster station as illustrated in FIG. 3) to an upper primary well casing 51.

A lower primary casing section 52 and a branch well liner 53 are each radially expanded by an expansion mandrel 54 inside the primary and branch wellbores such that the upper ends of the lower primary casing section 52 and said liner are firmly pressed against the lower branches of the bifurcation element 50 which serve as an electric contact and receptacle.

FIG. 7 shows an inflow section of a branch wellbore 60 where the branch well liner 61 has perforations 62 through which oil and/or gas is allowed to flow from the surrounding oil and/or gas bearing formation 63 into the wellbore 60 as illustrated by arrows 64.

An equipment carrier sleeve 65 is sealingly secured inside the liner 61 by means of a pair of expandable packers 66.

The sleeve 65 has perforations 67 and is surrounded by a movable sleeve-type valve body 68 which has perforations 69 which are, in the position shown in fig. 7, aligned with the perforations 67 of the sleeve 65. Because of the alignment of the perforations 67 and 69 oil and/or gas is permitted to flow into the wellbore 60.

FIG. 8 shows how the sleeve-type valve body 68 is moved such that the perforations 67 and 69 are unaligned and flow of oil and/or gas from the formation 63 into the wellbore 60 is interrupted.

The motion of the sleeve type valve body 68 is achieved by an electrical actuator 70 which is powered by a rechargeable lithium-ion high temperature battery 71, which has one electrode 72 which is electrically connected to the surrounding formation and another electrode 73 which is electrically connected to the liner 61.

The electrical direct current (DC) power which is transmitted via the primary casing (not shown) to the branch well liner 61 is used to trickle charge the battery 71. The battery

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71 powers the valve actuator 70 and optionally also flow, pressure, temperature, composition, reservoir imaging and/or seismic equipment (not shown) carried by the sleeve 65 and signals generated by the equipment are transmitted to surface monitoring equipment by transmission of VLC or ELC pulsed electromagnetic signals which involve voltage level oscillations around the DC voltage level of the branch well liner 61 via the electrode 72 and said liner 61 to the primary well casing (not shown) and an electrical cable connected to the upper end of said casing (as is shown in FIG. 1) to surface monitoring and/or control equipment.

In the example shown in FIG. 7 the battery 71 is a tubular ceramic lithium-ion high-temperature battery and a series of reservoir imaging sensors 75 are embedded in the formation 63 surrounding the wellbore 60. These sensors 75 transmit and/or receive signals via inductive couplers 76 which are connected to signal processing equipment (not shown) mounted on the sleeve 65. Said processing equipment is able to actuate the valve body 68 and/or to transmit electric reservoir imaging data acquired by the sensors 75 via the wall of the well liner 61 and well tubulars in the primary or mother wellbore to production monitoring equipment at the platform or other surface facilities as illustrated in FIG. 1.

We claim:

1. A multilateral well and electric transmission system, comprising:

a primary wellbore in which a primary well tubular is arranged; and

a branch wellbore in which a branch well tubular is arranged;

wherein the branch well tubular is connected in an electrically conductive manner to the primary well tubular such that the primary and branch well tubulars form a link for transmission of electrical power and/or signals between the primary and branch wellbore;

wherein the primary and branch well tubulars form a link for transmitting low voltage power from a first pole of an electrical power source which is electrically connected to the primary well tubular to electrically powered equipment within the branch wellbore which is electrically connected to the branch well tubular, and wherein a second pole of the electrical power source and the branch well tubulars are electrically connected to the earth;

wherein the electrically powered equipment comprises a re-chargeable battery which is trickle-charged by the low voltage electrical power transmitted via the well tubulars;

wherein the electrically powered equipment comprises measuring and/or control equipment which is powered by a rechargeable lithium-ion high-temperature battery and is mounted on an equipment carrier module which is removably secured within the branch well tubular such that one electrode of the battery is electrically connected to the branch well tubular and another electrode of the battery is electrically connected to the subsurface earth formation surrounding the branch wellbore;

wherein the equipment carrier module formed by a sleeve which is removably connected within the branch well tubular by means of a number of expandable clamps; and

wherein the sleeve spans an inflow area of the branch wellbore where the branch well tubular is perforated, the expandable clamps consist of a pair of expandable packers which seal off an annular space between the

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branch well tubular and sleeve near each end of the sleeve and wherein the sleeve is provided with one or more fluid inlet ports which can be opened and closed by one or more valves which are powered by the rechargeable battery.

2. The multilateral well and electric transmission system of claim 1, wherein the branch well tubular is a radially expandable tubular which is made of an electrically conductive material and which is radially expanded within the branch well during installation and wherein an electrically conductive receptacle is arranged at or near a branchpoint such that the expanded branch well tubular is pressed into electrical contact with the receptacle as a result of the expansion process.

3. The multilateral well and electric transmission system of claim 2, wherein the receptacle is formed by the primary well tubular itself and the branch tubular has a downstream end which is radially expanded against the inner wall of the primary well tubular and extends through a window in the primary well tubular into the branch wellbore.

4. The multilateral well and electric transmission system of claim 2, wherein the receptacle is formed by a tubular branch section of a bifurcation element, which bifurcation element has a primary section which is electrically connected to the primary well tubular and the tubular branch section extends from the primary wellbore into the branch wellbore.

5. The multilateral well and electric transmission system of claim 2, wherein the primary and branch well tubulars are made of a formable steel grade and the branch well tubular is expanded during installation such that the expanded branch well tubular has an inner diameter which is at least 0.9 times the inner diameter of the primary well tubular.

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6. The multilateral well and electric transmission system of claim 1, wherein at least one of the primary and branch well tubulars is equipped with at least one electrical booster station, which station spans an electrically non-conductive section of the well tubular and which station is electrically connected to an electrically conductive parts of the well tubular at both sides of the electrically non-conductive section thereof.

7. The multilateral well and electric transmission system of claim 6, wherein the electrically non-conductive section of the well tubular is formed by an electrically non-conductive annular seal which is arranged between overlapping co-axial sections of the well tubular and wherein the electrical booster station is arranged within the outermost section of the well tubular near the end of the innermost section of the well tubular such that one electrode of the electrical booster station is connected to said outermost section and another electrode of said station is electrically connected to said innermost section.

8. The multilateral well and electrical transmission system of claim 7, which comprises a plurality of branch wellbores and a plurality of electrical booster stations.

9. A sleeve-type equipment carrier module for use in a multilateral well and electric transmission system according to claim 1, which module is sealably securable in an inflow region of the well and comprises one or more fluid inlet ports which can be opened and closed by one or more valves which are powered by a rechargeable battery which is in use trickle charged by transmitting low voltage electrical power through tubulars in the primary and branch wellbore.

* * * * *

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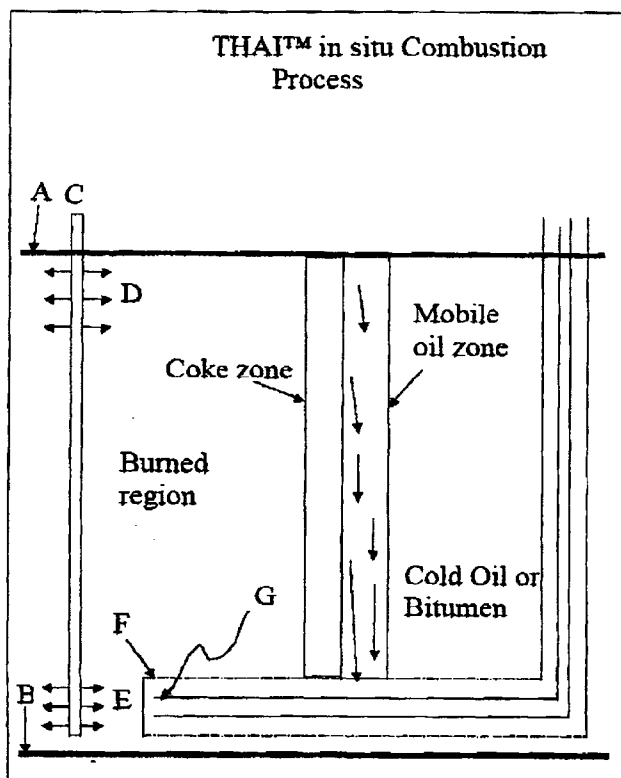
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(54) Title: **DILUENT-ENHANCED IN-SITU COMBUSTION HYDROCARBON RECOVERY PROCESS**



(57) Abstract: A modified process for recovering oil from an underground reservoir using the toe-to-heel in situ combustion process. A diluent, namely a hydrocarbon condensate, is injected within a horizontal wellbore portion, preferably proximate the toe, of a vertical-horizontal well pair, or alternatively into an adjacent injection well, or both, to increase mobility of oil.

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For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.

**DILUENT-ENHANCED IN-SITU COMBUSTION
HYDROCARBON RECOVERY PROCESS**

5 FIELD OF THE INVENTION

This invention relates to a process for improved productivity when undertaking oil recovery from an underground reservoir by the toe-to-heel in situ combustion process employing a horizontal production well, such as disclosed in U.S. Patent
10 Nos. 5,626,191 and 6,412,557. More particularly, it relates to an in situ combustion process in which a diluent, namely a hydrocarbon condensate, is injected at the toe of a vertical-horizontal well pair adapted for use in an in situ combustion process.

15 BACKGROUND OF THE INVENTION AND DESCRIPTION OF THE PRIOR ART

U.S. Patents 5,626,191 and 6,412,557, incorporated herein in their entirety, disclose in situ combustion processes for producing oil from an underground reservoir (100) utilizing an injection well (102) placed relatively high in an oil
20 reservoir (100) and a production well (103-106) completed relatively low in the reservoir (100). The production well has a horizontal leg (107) oriented generally perpendicularly to a generally linear and laterally extending upright combustion front propagated from the injection well (102). The leg (107) is positioned in the path of the advancing combustion front. Air, or other oxidizing gas, such as
25 oxygen-enriched air, is injected through wells 102, which may be vertical wells, horizontal wells or combinations of such wells.

The process of U.S. Patent 5,626,191 is called "THAI™", an acronym for "toe-to-heel air injection" and the process of U.S. Patent 6,412,557 is called "Capri™", the
30 Trademarks being held by Archon Technologies Ltd., a subsidiary of Petrobank Energy and Resources Ltd., Calgary, Alberta, Canada.

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What is needed is one or more methods to increase productivity when undertaking oil recovery from an underground reservoir by the toe-to-heel in situ combustion process employing horizontal production wells .

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SUMMARY OF THE INVENTION

10 The invention, in a broad embodiment, comprises injecting a diluent in the form of a hydrocarbon condensate via tubing at the toe of the toe-to-heel in situ combustion process employed a horizontal production well , which adds to well productivity and advantageously results in various production economies over the THAI and CAPRI processes to date employed.

15 A hydrocarbon condensate is typically a low-density, high-API gravity liquid hydrocarbon phase that generally occurs in association with natural gas. Its presence as a liquid phase depends on temperature and pressure conditions in the reservoir allowing condensation of liquid from vapor.

20 The production of condensate from reservoirs can be complicated because of the pressure sensitivity of some condensates. Specifically, during production, there is a risk of the condensate changing from gas to liquid if the reservoir pressure (and thus temperature) drops below the dew point during production. Reservoir pressure (and thus temperature) can be maintained by fluid injection if gas
25 production is preferable to liquid production. Gas produced in association with condensate is called wet gas. The API gravity of condensate is typically 50 degrees to 120 degrees.

30 The benefit of injection a high-API hydrocarbon condensate (40+ API Gravity) into the tubing in a THAI™ or CAPRI™ In situ hydrocarbon extraction method is that a

steam generator or water treatment facilities, as are typically required in THAI™ and CAPRI™ in situ hydrocarbon extraction methods, would not be required. This results in a significant expense savings, not only in avoiding the cost of having to divert a portion of the produced hydrocarbon to produce heated steam, but also in having to have the necessary steam generation equipment and pollution control equipment present to do so. Process operations costs would not be increased since the diluent in liquid form is purchased anyway, and typically in prior art methods involving THAI and CAPRI, mixed with the extracted hydrocarbon at the surface in order to better pump the hydrocarbon to storage facilities or refineries.

The diluent would dissolve in the liquid oil in the horizontal wellbore and reduce its viscosity, which would advantageously reduce pressure drop in the horizontal well. It would also reduce the density of the oil, facilitating its rise to the surface by gas-lift.

The addition of a diluent in the form of a hydrocarbon condensate, preferably a liquid, via tubing at the toe of a horizontal production well in a toe-to-heel in situ combustion hydrocarbon recovery process, may be done in combination with any of the steam, water, or oxidizing gas injection methods disclosed in any of US Provisional patent application 60/577,779 filed June 7, 2004 and/or Patent Cooperation Patent Application PCT/CA2005/000883 filed June 6, 2005, each of which are incorporated herein by reference in their respective entireties.

Accordingly, in one broad embodiment of the method of the present invention, the invention comprises a process for extracting liquid hydrocarbons from an underground reservoir comprising the steps of:

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- (a) providing at least one injection well for injecting an oxidizing gas into the underground reservoir;
- 5 (b) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is
- 10 closer to the injection well than the heel portion;
- (c) injecting an oxidizing gas through the Injection well to conduct in situ combustion, so that combustion gases are produced so as to cause the combustion gases to progressively advance as a front,
- 15 substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;
- (d) providing a tubing inside the production well for the purpose of injecting a hydrocarbon condensate into said horizontal leg portion of said production well;
- 20
- (e) injecting said hydrocarbon condensate into said tubing so that said condensate is conveyed proximate said toe portion of said
- 25 horizontal leg portion via said tubing ; and
- (f) recovering hydrocarbons in the horizontal leg of the production well from said production well.

In a further broad embodiment of the invention, the present invention comprises a process for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:

- 5 (a) providing at least one injection well for injecting an oxidizing gas into an upper part of an underground reservoir;
- (b) providing at least one injection well for a hydrocarbon condensate diluent into a lower part of an underground reservoir;
- 10 (c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of
- 15 its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;
- (d) injecting an oxidizing gas through the injection well for in situ
- 20 combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;
- 25 (e) injecting a hydrocarbon condensate diluent, into said injection well ;
and

(f) recovering hydrocarbons in the horizontal leg of the production well from said production well.

In a still further embodiment of the invention, the present invention comprises the combination of the above steps of injecting a hydrocarbon diluent to the formation via the injection well, and as well injecting a medium via tubing in the horizontal leg. Accordingly, in this further embodiment the present invention comprises a method for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:

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a) providing at least one injection well for injecting an oxidizing gas into an upper part of an underground reservoir;

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b) providing at least one injection well for a hydrocarbon diluent into a lower part of an underground reservoir;

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c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;

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d) providing a tubing inside the production well for the purpose of injecting a hydrocarbon condensate diluent into said horizontal leg portion of said production well;

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5 e) injecting an oxidizing gas through the injection well for in situ combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;

10 f) injecting a hydrocarbon condensate diluent into said injection well and into said tubing; and

(g) recovering hydrocarbons in the horizontal leg of the production well from said production well.

15 The hydrocarbon condensate contemplated is preferably a condensate selected from the group of condensates consisting of ethane, butanes, pentanes, heptanes, hexanes, octanes, and higher molecular weight hydrocarbons, or mixtures thereof, but may be any other hydrocarbon diluent, such as volatile hydrocarbons such as naphtha or gasoline.

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BRIEF DESCRIPTION OF THE DRAWINGS

Figure 1 is a schematic of the THAI™ in situ combustion process with labeling as follows:

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Item A represents the top level of a heavy oil or bitumen reservoir, and B represents the bottom level of such reservoir/formation. C represents a vertical well with D showing the general injection point of an oxidizing gas such as air.

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E represents a general location for the injection of steam or a non-oxidizing gas into the reservoir. This is part of the present invention.

5 F represents a partially perforated horizontal well casing. Fluids enter the casing and are typically conveyed directly to the surface by natural gas lift through another tubing located at the heel of the horizontal well (not shown).

10 G represents a tubing placed inside the horizontal leg. The open end of the tubing may be located near the end of the casing, as represented, or elsewhere. The tubing can be 'coiled tubing' that may be easily relocated inside the casing. This is part of the present invention.

15 The elements E and G are part of the present invention and steam or non-oxidizing gas may be injected at E and/or at G. E may be part of a separate well or may be part of the same well used to inject the oxidizing gas. These injection wells may be vertical, slanted or horizontal wells or otherwise and each may serve several horizontal wells.

20 For example, using an array of parallel horizontal leg as described in U.S. Patents 5,626,191 and 6,412,557, the steam, water or non-oxidizing gas may be injected at any position between the horizontal legs in the vicinity of the toe of the horizontal legs.

25 Figure 2 is a schematic diagram of the Model reservoir. The schematic is not to scale. Only an 'element of symmetry' is shown. The full spacing between horizontal legs is 50 meters but only the half-reservoir needs to be defined in the STARS™ computer software. This saves computing time. The overall dimensions of the Element of Symmetry are:

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length A-E is 250 m; width A-F is 25 m; height F-G is 20 m.

The positions of the wells are as follows:

- 5 Oxidizing gas injection well J is placed at B in the first grid block 50 meters (A-B) from a corner A. The toe of the horizontal well K is in the first grid block between A and F and is 15 m (B-C) offset along the reservoir length from the injector well J. The heel of the horizontal well K lies at D and is 50 m from the corner of the reservoir, E. The horizontal section of the horizontal well K is 135 m (C-D) in
10 length and is placed 2.5 m above the base of the reservoir (A-E) in the third grid block.

- The Injector well J is perforated in two (2) locations. The perforations at H are injection points for oxidizing gas, while the perforations at I are injection points for
15 steam or non-oxidizing gas. The horizontal leg (C-D) is perforated 50% and contains tubing open near the toe (not shown, see Figure 1).

Figure 3 is a graph plotting oil production rate vs. CO₂ rate in the produced gas, drawing on Example 7 discussed below.

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DESCRIPTION OF THE PREFERRED EMBODIMENT

- The operation of the THAI™ process has been described in U.S. Patents
25 5,626,191 and 6,412,557 and will be briefly reviewed. The oxidizing gas, typically air, oxygen or oxygen-enriched air, is injected into the upper part of the reservoir. Coke that was previously laid down consumes the oxygen so that only oxygen-free gases contact the oil ahead of the coke zone. Combustion gas temperatures of typically 600 °C. and as high as 1000 °C. are achieved from the high-temperature

oxidation of the coke fuel. In the Mobile Oil Zone (MOZ), these hot gases and steam heat the oil to over 400 °C, partially cracking the oil, vaporizing some components and greatly reducing the oil viscosity. The heaviest components of the oil, such as asphaltenes, remain on the rock and will constitute the coke fuel
5 later when the burning front arrives at that location. In the MOZ, gases and oil drain downward into the horizontal well, drawn by gravity and by the low- pressure sink of the well. The coke and MOZ zones move laterally from the direction from the toe towards the heel of the horizontal well. The section behind the combustion front is labeled the Burned Region. Ahead of the MOZ is cold oil.

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With the advancement of the combustion front, the Burned Zone of the reservoir is depleted of liquids (oil and water) and is filled with oxidizing gas. The section of the horizontal well opposite this Burned Zone is in jeopardy of receiving oxygen which will combust the oil present inside the well and create extremely high
15 wellbore temperatures that would damage the steel casing and especially the sand screens that are used to permit the entry of fluids but exclude sand. If the sand screens fail, unconsolidated reservoir sand will enter the wellbore and necessitate shutting in the well for cleaning-out and remediation with cement plugs. This operation is very difficult and dangerous since the wellbore can contain explosive
20 levels of oil and oxygen.

In order to quantify the effect of fluid injection into the horizontal wellbore, a number of computer numerical simulations of the process were conducted. Steam was injected at a variety of rates into the horizontal well by two methods: 1. via
25 tubing placed inside the horizontal well, and 2. via a separate well extending near the base of the reservoir in the vicinity of the toe of the horizontal well. Both of these methods reduced the predilection of oxygen to enter the wellbore but gave surprising and counterintuitive benefits: the oil recovery factor increased and build-

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up of coke in the wellbore decreased. Consequently, higher oxidizing gas injection rates could be used while maintaining safe operation.

It was found that both methods of adding steam to the reservoir provided
5 advantages regarding the safety of the THAI™ Process by reducing the tendency of oxygen to enter the horizontal wellbore. It also enabled higher oxidizing gas injection rates into the reservoir, and higher oil recovery.

Extensive computer simulation of the THAI™ Process was undertaken to evaluate
10 the consequences of reducing the pressure in the horizontal wellbore by injecting steam or non-oxidizing gas. The software was the STARS™ In Situ Combustion Simulator provided by the Computer Modelling Group, Calgary, Alberta, Canada.

Table 4. List of Model Parameters.

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Simulator: STARS™ 2003.13, Computer Modeling Group Limited

Model dimensions:

Length 250 m, 100 grid blocks, each

Width 25 m, 20 grid blocks

Height 20 m, 20 grid blocks

Grid Block dimensions: 2.5 m x 2.5 m x 1.0 m (LWH).

Horizontal Production Well:

A discrete well with a 135 m horizontal section extending from grid block 26,1, 3 to 80,1,3

The toe is offset by 15 m from the vertical air injector..

Vertical Injection Well:

Oxidizing gas(air) injection points: 20, 1, 1:4 (upper 4-grid blocks)

Oxidizing gas injection rates: 65,000 m3/d, 85,000 m3/d or 100,000 m3/d

Steam injection points: 20, 1, 19:20 (lower 2-grid blocks)

Rock/fluid Parameters:

Components: water, bitumen, upgrade, methane, CO₂, CO/ N₂, oxygen, coke

Heterogeneity: Homogeneous sand.

Permeability: 6.7 D (h), 3.4 D (v)

Porosity: 33 %

Saturations: Bitumen 80%, water 20%, gas Mole fraction 0.114

Bitumen viscosity: 340,000 cP at 10 °C.

Bitumen average molecular weight: 550 AMU

Upgrade viscosity: 664 cP at 10 °C.

Upgrade average molecular weight: 330 AMU

Physical Conditions:

Reservoir temperature: 20 °C.

Native reservoir pressure: 2600 kPa.

Bottomhole pressure: 4000 kPa.

Reactions:

1. 1.0 Bitumen $\longrightarrow$ 0.42 Upgrade + 1.3375 CH₄ + 20 Coke

2. 1.0 Bitumen + 16 O₂ + 0.05 $\longrightarrow$ 12.5 water + 5.0 CH₄ + 9.5 CO₂ + 0.5 CO/N₂ + 15 Coke

3. 1.0 Coke + 1.225 O₂ $\longrightarrow$ 0.5 water + 0.95 CO₂ + 0.05 CO/N₂

EXAMPLES5 **Example 1**

Table 1a shows the simulation results for an air injection rate of 65,000 m³/day (standard temperature and pressure) into a vertical injector (E in Figure 1). The case of zero steam injected at the base of the reservoir at point I in well J is not part of the present invention. At 65,000 m³/day air rate, there is no oxygen entry

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into the horizontal wellbore even with no steam injection and the maximum wellbore temperature never exceeds the target of 425 °C.

However, as may be seen from the data below, injection of low levels of steam at levels of 5 and 10 m³/day (water equivalent) at a point low in the reservoir (E in Figure 1) provides substantial benefits in higher oil recovery factors, contrary to intuitive expectations. Where the injected medium is steam, the data below provides the volume of the water equivalent of such steam, as it is difficult to otherwise determine the volume of steam supplied as such depends on the pressure at the formation to which the steam is subjected to. Of course, when water is injected into the formation and subsequently becomes steam during its travel to the formation, the amount of steam generated is simply the water equivalent given below, which typically is in the order of about 1000x (depending on the pressure) of the volume of the water supplied.

Table 1a: AIR RATE 65,000 m³/day- Steam injected at reservoir base.

Steam Injection Rate m ³ /day (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
0	410	90	0	35.1	28.3
5	407	79	0	38.0	29.0
10	380	76	0	43.1	29.8

* Not part of the present invention.

Example 2

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Table 1b shows the results of injecting steam into the horizontal well via the internal tubing, G, in the vicinity of the toe while simultaneously injecting air at 65,000 m³/day (standard temperature and pressure) into the upper part of the reservoir. The maximum wellbore temperature is reduced in relative proportion to the amount of steam injected and the oil recovery factor is increased relative to the base case of zero steam. Additionally, the maximum volume percent of coke deposited in the wellbore decreases with increasing amounts of injected steam. This is beneficial since pressure drop in the wellbore will be lower and fluids will flow more easily for the same pressure drop in comparison to wells without steam injection at the toe of the horizontal well.

Table 1b. AIR RATE 65,000 m³/day- Steam injected in well tubing.

Steam Injection Rate m ³ /day (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
0	410	90	0	35.1	28.6
5	366	80	0	43.4	30.0
10	360	45	0	43.4	29.8

* Not part of the present invention.

Example 3

In this example, the air injection rate was increased to 85,000 m³/day (standard temperature and pressure) and resulted in oxygen breakthrough as shown in Table 2a. An 8.8% oxygen concentration was indicated in the wellbore for the base case of zero steam injection. Maximum wellbore temperature reached 1074 °C and coke was deposited decreasing wellbore permeability by 97%. Operating with the simultaneous injection of 12 m³/day (water equivalent) of steam at the

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base of the reservoir via vertical injection well C (see Fig. 1) provided an excellent result of zero oxygen breakthrough, acceptable coke and good oil recovery.

Table 2a: AIR RATE 85,000 m³/day- Steam injected at reservoir base.

Steam Injection Rate m ³ /d (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
0	1074	97	8.8		
5	518	80	0		
12	414	43	0	36.1	33.4

* Not part of the present invention.

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Example 4.

Table 2b shows the combustion performance with 85,000 m³/day air (standard temperature and pressure) and simultaneous injection of steam into the wellbore via an internal tubing G (see Fig. 1) . Again 10 m³/day (water equivalent) of steam was needed to prevent oxygen breakthrough and an acceptable maximum wellbore temperature.

Table 2b AIR RATE 85,000 m³/d. Steam injected in well tubing.

Steam Injection Rate m ³ /d (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
0	1074	100	8.8		
5	500	96	1.8		

10 407 45 0 37.3 33.2

* Not part of the present invention.

Example 5

- 5 In order to further test the effects of high air injection rates, several runs were conducted with 100,000 m³/day air injection. Results in Table 3a indicate that with simultaneous steam injection at the base of the reservoir (ie at location B-E in vertical well C-ref. Fig. 1), 20 m³/day (water equivalent) of steam was required to stop oxygen breakthrough into the horizontal leg, in contrast to only 10 m³/day steam (water equivalent) at an air injection rate of 85,000 m³/day.
- 10

Table 3a: AIR RATE 100,000 m³/day-Steam injected at reservoir base.

Steam Injection Rate m ³ /day (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
0	1398	100	10.4		
5	1151	100	7.2		
10	1071	100	6.0		
20	425	78	0	34.5	35.6

* Not part of the present invention.

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Example 6

Table 3b shows the consequence of injecting steam into the well tubing G (ref. Fig. 1) while injecting 100,000 m³/day air into the reservoir. Identically with steam

injection at the reservoir base, a steam rate of 20 m³/day (water equivalent) was required in order to prevent oxygen entry into the horizontal leg.

Table 3b AIR RATE 100,000 m³/d. Steam injected in well tubing.

Steam Injection Rate m ³ /day (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
0	1398	100	10.4		
5	997	100	6.0		
10	745	100	3.8		
20	425	38	0	33.9	35.6

5

Example 7

Table 4 below shows comparisons between injecting oxygen and a combination of non-oxidizing gases, namely nitrogen and carbon dioxide, into a single vertical injection well in combination with a horizontal production well in the THAI™ process via which the oil is produced, as obtained by the STARS™ In Situ Combustion Simulator software provided by the Computer Modelling Group, Calgary, Alberta, Canada. The computer model used for this example was identical to that employed for the above six examples, with the exception that the modeled reservoir was 100 meters wide and 500 meters long. Steam was added at a rate of 10 m³/day via the tubing in the horizontal section of the production well for all runs.

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Test #	Injection Rate, km ³ /day			Mol % Oxygen	Mol % CO ₂	Total Injection Rate, km ³ /day	Production Rate, km ³ /day		Produced Gas Mol %	Oil Rate	Cumulative Oil Recovery
	O ₂	CO ₂	N ₂	Injected	Injected	km ³ /day	CO ₂	N ₂	CO ₂	m ³ /day (1-year)	m ³
1	17.85	0	67.15	21	0	85	13.1	67.2	16.3	41	9700
2	8.93	33.57	0	21	79	42.5	37.9	0.0	96.0	54	12780
3	25	0	0	100	0	25	21.3	0.0	96.0	47	10078
4	17.85	67.15	0	21	79	85	75.0	0.0	96.0	136	20000
5	42.5	0	0	100	0	42.5	38.1	0.0	96.0	57	12704
6	42.5	42.5	0	50	50	85	74.2	0.0	96.0	113	28104
7	8.93	42.5	33.57	11	50	85	47.2	33.6	57.4	70	12000

- As may be seen from above Table 4 comparing Run 1 and Run 2, when the oxygen and inert gas are reduced by 50% as in Run2, the oil recovery is nevertheless the same as in Run 1, providing that the inert gas is CO₂. This means that the gas compression costs are cut in half in Run 2, while oil is produced faster.
- 10 As may further be seen from above Table 4, Run #1 having 17.85 molar % of oxygen and 67.15% nitrogen injected into the injection well, estimated oil recovery rate was 41 m³/day. In comparison, using a similar 17.85 molar% oxygen injection with 67.15 molar % carbon dioxide as used in Run #4, a 3.3 times increase in oil production (136 m³/day) is estimated as being achieved.
- 15 As may be further seen from Table 4 above, when equal amounts of oxygen and CO₂ are injected as in Run 6, still with a total injected volume of 85,000 m³/day, oil recovery was increased 2.7-fold.
- 20 Run 7 shows the benefit of adding CO₂ to air as the injectant gas. Compared with Run 1, oil recovery was increased 1.7-fold without increasing compression costs.

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The benefit of this option is that oxygen separation equipment is not needed.

Referring now to Figure 3, which is a graph showing a plot of oil production rate versus CO₂ rate in the produced gas (drawing on Example 7 above), there is a strong correlation between these parameters for in situ combustion processes. CO₂ production rate depends upon two CO₂ sources: the injected CO₂ and the CO₂ produced in the reservoir from coke combustion, so there is a strong synergy between CO₂ flooding and in situ combustion even in reservoirs with immobile oils, which is the present case.

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SUMMARY

For a fixed amount of steam injection, the average daily oil recovery rate increased with air injection rate. This is not unexpected since the volume of the sweeping fluid is increased. However, it is surprising that the total oil recovered decreases as air rate is increased. This is during the life of the air injection period (time for the combustion front to reach the heel of the horizontal well). Moreover, with carbon dioxide injected in the vertical well, and/or in the horizontal production well, production rates improved production rates can be expected.

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Although the disclosure described and illustrates preferred embodiments of the invention, it is to be understood that the invention is not limited to these particular embodiments. Many variations and modifications will now occur to those skilled in the art. For definition of the invention, reference is to be made to the appended claims.

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The embodiments of the invention in which an exclusive property or privilege is claimed are defined as follows:

1. A process for extracting liquid hydrocarbons from an underground reservoir comprising the steps of:
 - (a) providing at least one injection well for injecting an oxidizing gas into the underground reservoir;
 - (b) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;
 - (c) injecting an oxidizing gas through the injection well to conduct in situ combustion, so that combustion gases are produced so as to cause the combustion gases to progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;
 - (d) providing a tubing inside the production well within said vertical leg and at least a portion of said horizontal leg for the purpose of injecting a hydrocarbon condensate, into said horizontal leg portion of said production well proximate a combustion front formed at a horizontal distance along said horizontal leg of said production well;

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(e) injecting a hydrocarbon condensate diluent into said tubing so that said condensate is conveyed proximate said toe portion of said horizontal leg portion via said tubing ; and

(f) recovering hydrocarbons in the horizontal leg of the production well from said production well.

2. The process of Claim 1 wherein said hydrocarbon condensate diluent is a condensate selected from the group of condensates consisting of ethane, butanes, pentanes, heptanes, hexanes, octanes, and higher molecular weight hydrocarbons, or mixtures thereof.
3. The process of Claim 1, wherein said hydrocarbon condensate is VAPEX.
4. The process of Claim 1 wherein the injection well is a vertical, slant or horizontal well.
5. The process of Claim 1, said step of injecting said hydrocarbon condensate further serves to pressurize said horizontal well to a pressure to permit injection of said medium into the underground reservoir.
6. The process of claim 1, said step of injecting said hydrocarbon condensate comprises injecting said condensate at a temperature and pressure at which said condensate exists in liquid form.
7. The process of claim 1, said step of injecting said hydrocarbon condensate comprises injecting said condensate at a temperature and pressure at which such condensate exists in gaseous form.

8. The process of claim 1 wherein said hydrocarbon condensate is injected into said tubing in combination with a medium selected from the group of mediums consisting of steam, water, or a non-oxidizing gas, or mixtures thereof.
9. The process of claim 1 wherein an open end of the tubing is in the vicinity of the toe of the horizontal section so as to permit delivery of said condensate to said toe.
10. The process of claim 1 or 9 wherein the tubing is partially pulled back or otherwise repositioned for the purpose of altering a point of injection of the condensate along the horizontal leg.
11. The process of Claim 1 wherein said condensate is injected continuously or periodically.
12. A process for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:
 - (a) providing at least one injection well for injecting an oxidizing gas into an upper part of an underground reservoir;
 - (b) said at least one injection well further adapted for injecting steam, a non-oxidizing gas, or water which is subsequently heated to steam, into a lower part of an underground reservoir;
 - (c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection

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well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;

(d) injecting an oxidizing gas through the injection well for in situ combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;

(e) injecting a hydrocarbon condensate into said injection well; and

(f) recovering hydrocarbons in the horizontal leg of the production well from said production well.

13. A process for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:

(a) providing at least one oxidizing gas injection well for injecting an oxidizing gas into an upper part of an underground reservoir;

(b) providing at least one other injection well for injecting a hydrocarbon condensate into a lower part of an underground reservoir;

(c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its

connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the oxidizing gas injection well than the heel portion;

(d) injecting an oxidizing gas through the oxidizing injection well for in situ combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;

(e) injecting a hydrocarbon condensate, into said other injection well; and

(f) recovering hydrocarbons in the horizontal leg of the production well from said production well.

14. The process of Claim 12 or 13 wherein said hydrocarbon condensate is a condensate selected from the group of condensates consisting of ethane, butanes, pentanes, heptanes, hexanes, octanes, and higher molecular weight hydrocarbons, or mixtures thereof.

15. A method for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:

(a) providing at least one injection well for injecting an oxidizing gas into an upper part of an underground reservoir;

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- (b) said at least one injection well further adapted for injecting steam, a non-oxidizing gas, or water which is subsequently heated to steam, into a lower part of an underground reservoir;
- (c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;
- (d) providing a tubing inside the production well within said vertical leg and at least a portion of said horizontal leg for the purpose of injecting hydrocarbon condensate into said horizontal leg portion of said production well;
- (e) injecting an oxidizing gas through the injection well for in situ combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;
- (f) injecting a hydrocarbon condensate into said injection well and into said tubing; and
- (g) recovering hydrocarbons in the horizontal leg of the production well from said production well.

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16. The method of claim 15 wherein said hydrocarbon condensate is a condensate selected from the group of condensates consisting of ethane, butanes, pentanes, heptanes, hexanes, octanes, and higher molecular weight hydrocarbons, or mixtures thereof.
17. The method of claim 15 wherein the injection well is a vertical, slant or horizontal well.
18. A method for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:
 - (a) providing at least one injection well for injecting an oxidizing gas into an upper part of an underground reservoir;
 - (b) providing at least one other injection well for injecting steam, a non-oxidizing gas, or water which is subsequently heated to steam, into a lower part of an underground reservoir;
 - (c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;
 - (d) providing a tubing inside the production well within said vertical leg and at least a portion of said horizontal leg for the purpose of injecting a hydrocarbon condensate into said horizontal leg portion of said production well;

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- (e) injecting an oxidizing gas through the injection well for in situ combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;
 - (f) injecting a hydrocarbon condensate into said other injection well and into said tubing; and
 - (g) recovering hydrocarbons in the horizontal leg of the production well from said production well.
19. The method of claim 18 wherein said hydrocarbon condensate is a condensate selected from the group of condensates consisting of ethane, butanes, pentanes, heptanes, hexanes, octanes, and higher molecular weight hydrocarbons, or mixtures thereof.
20. The method of claim 18 wherein the injection well is a vertical, slant or horizontal well.

Figure 1. THAI™ in situ Combustion Process

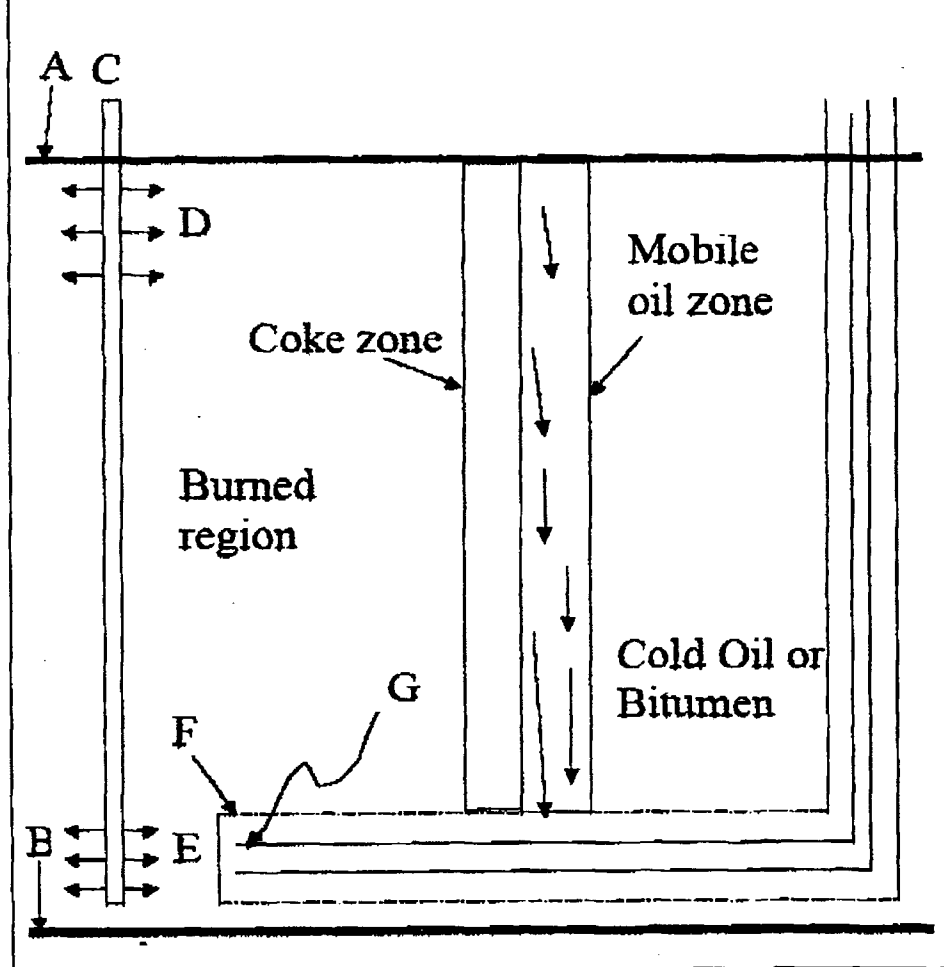


Figure 2. Reservoir Dimensions and Placement of Wells

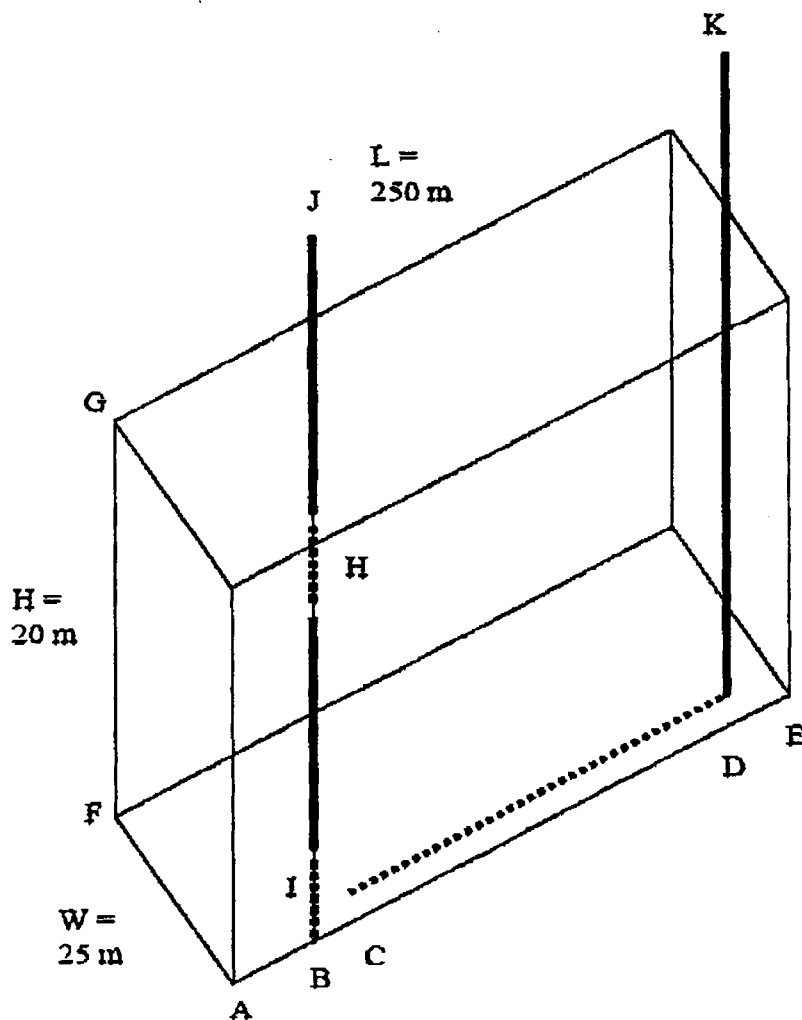
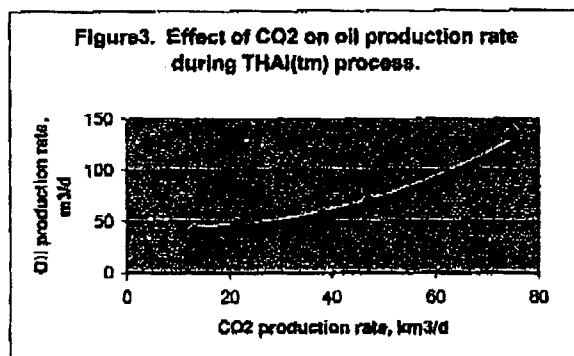


Figure 3. Graph Plotting Production Rate
versus CO₂ Rate in Produced Gas





US006412557B1

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(12) **United States Patent**
Ayasse et al.

(10) **Patent No.:** **US 6,412,557 B1**
(45) **Date of Patent:** **Jul. 2, 2002**

- (54) **OILFIELD IN SITU HYDROCARBON
UPGRADING PROCESS**
- (75) Inventors: **Conrad Ayasse**, Calgary (CA);
Malcolm Greaves, Bath (GB); **Alex
Turta**, Calgary (CA)
- (73) Assignee: **Alberta Research Council Inc.**,
Edmonton (CA)

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- (*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 0 days.

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(22) PCT Filed: **Dec. 4, 1998**
(86) PCT No.: **PCT/CA98/01127**

§ 371 (c)(1),
(2), (4) Date: **Aug. 25, 2000**

- (87) PCT Pub. No.: **WO99/30002**
PCT Pub. Date: **Jun. 17, 1999**

Related U.S. Application Data

- (60) Provisional application No. 60/069,182, filed on Dec. 11, 1997.
- (51) Int. Cl.⁷ **E21B 43/243**
(52) U.S. Cl. **166/261; 166/262; 166/272.3; 166/245**
(58) Field of Search **166/256, 261, 166/262, 272.3, 245**

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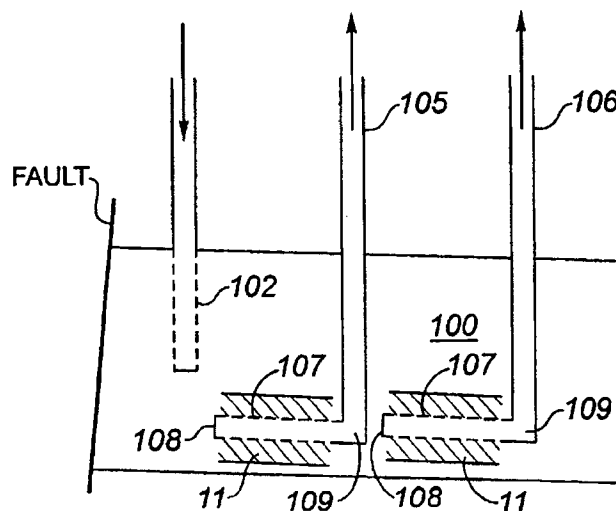
Primary Examiner—William Neuder

(74) *Attorney, Agent, or Firm*—Kurt D. Van Tassel;
Deborah G. VandenHoff; Van Tassel & Associates

(57) ABSTRACT

A well configuration is provided comprising an injection well (102) completed relatively high in an oil reservoir (100) and a production well (103-106) completed relatively low in the reservoir (100). The production well has a horizontal leg (107) oriented generally perpendicularly to a generally linear and laterally extending, upright combustion front propagated from the injection well (102). The leg (107) is positioned in the path of the advancing front. Oil upgrading catalyst has been emplaced along the horizontal leg. The production well (103-106) is maintained open, thereby providing a low pressure sink which induces the front to advance along the leg. The hot combustion gases react with the commingled oil over the catalyst to provide in situ upgrading.

16 Claims, 6 Drawing Sheets



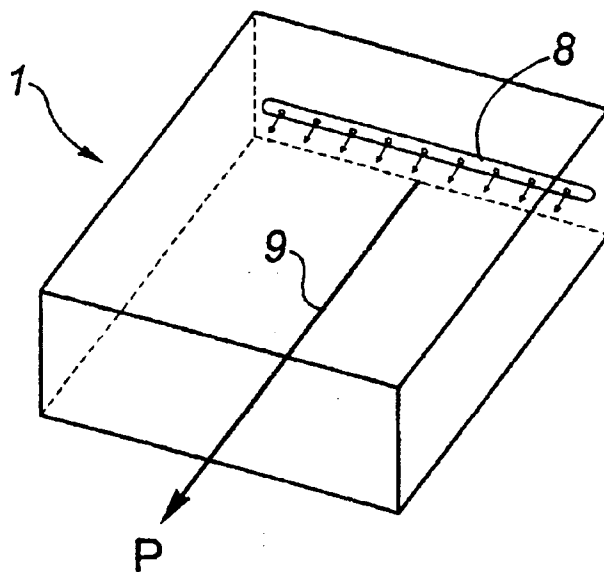


FIG. 1

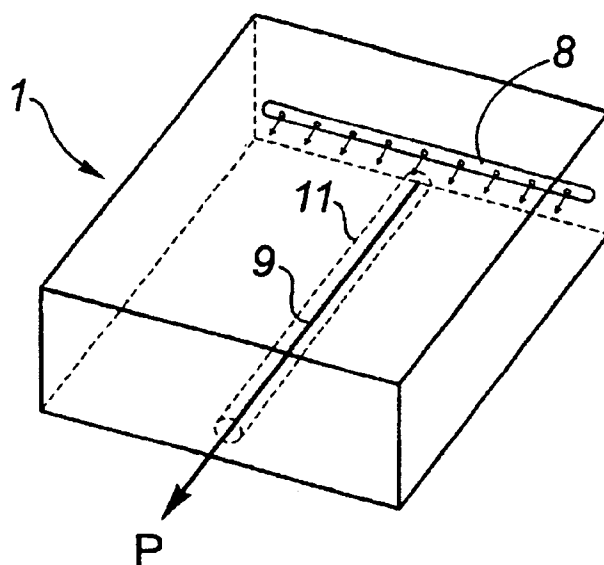


FIG. 2

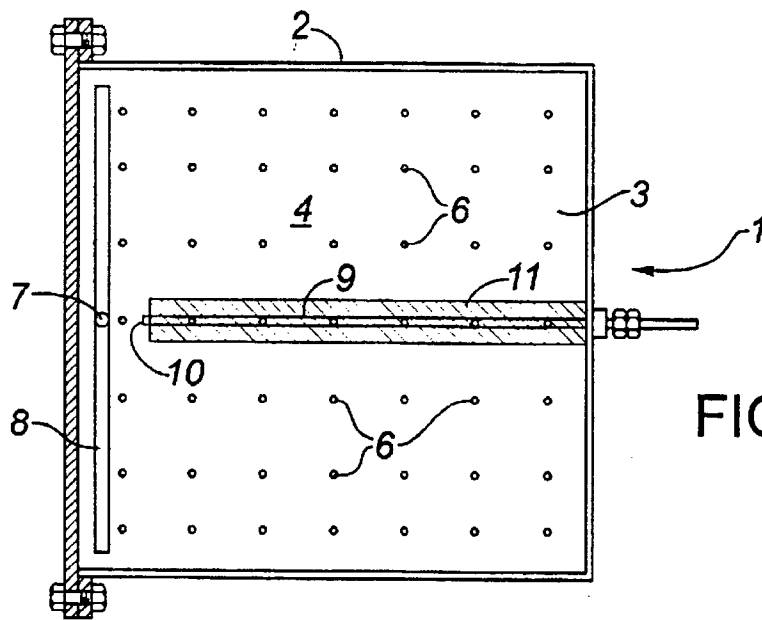


FIG. 3A

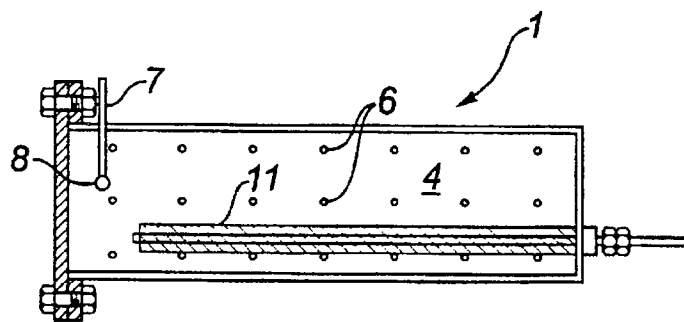


FIG. 3B

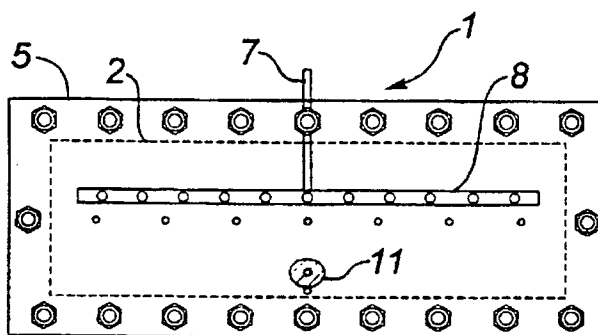


FIG. 3C

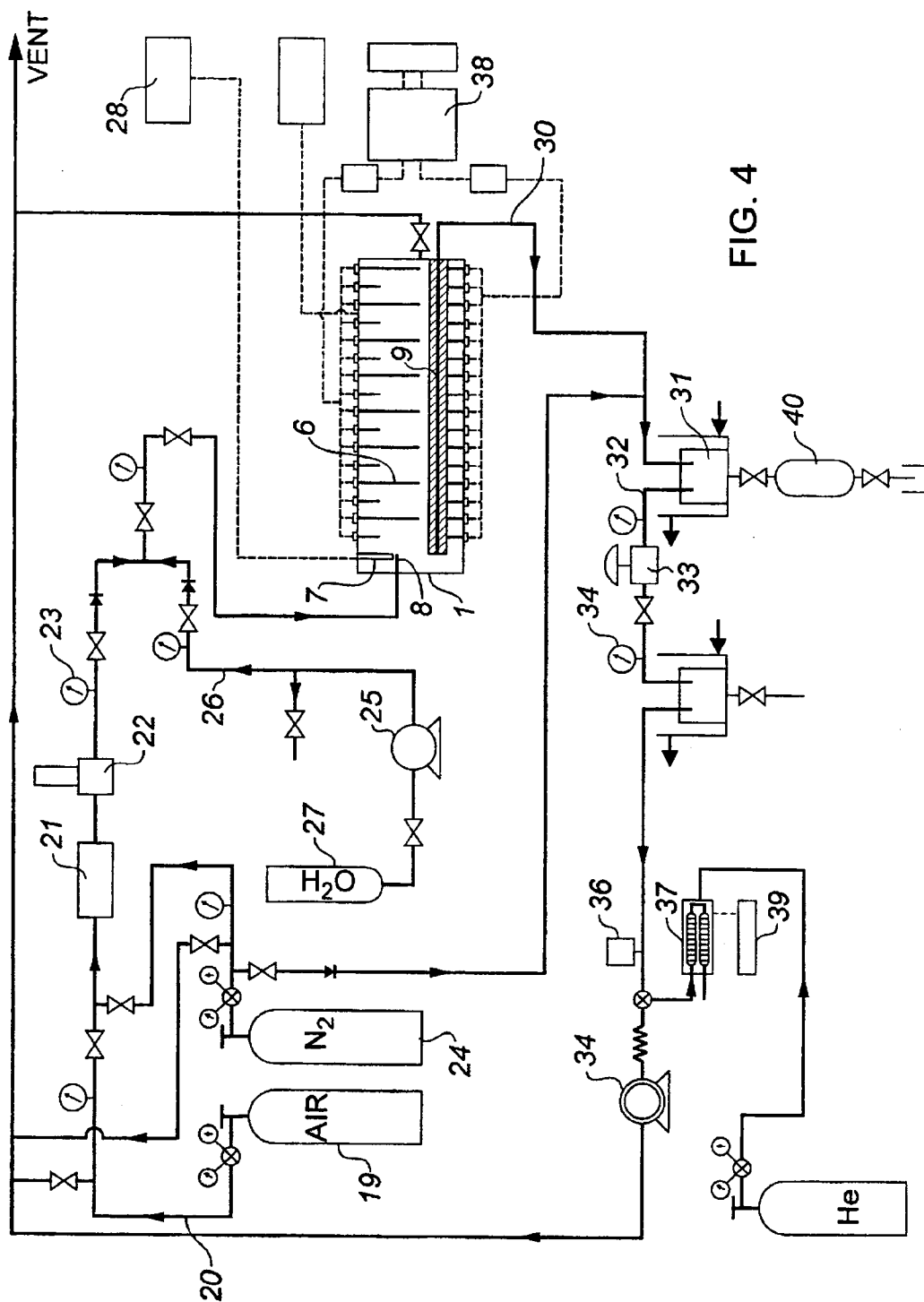


FIG. 4

FIG. 5A

BASE WOLF LAKE OIL

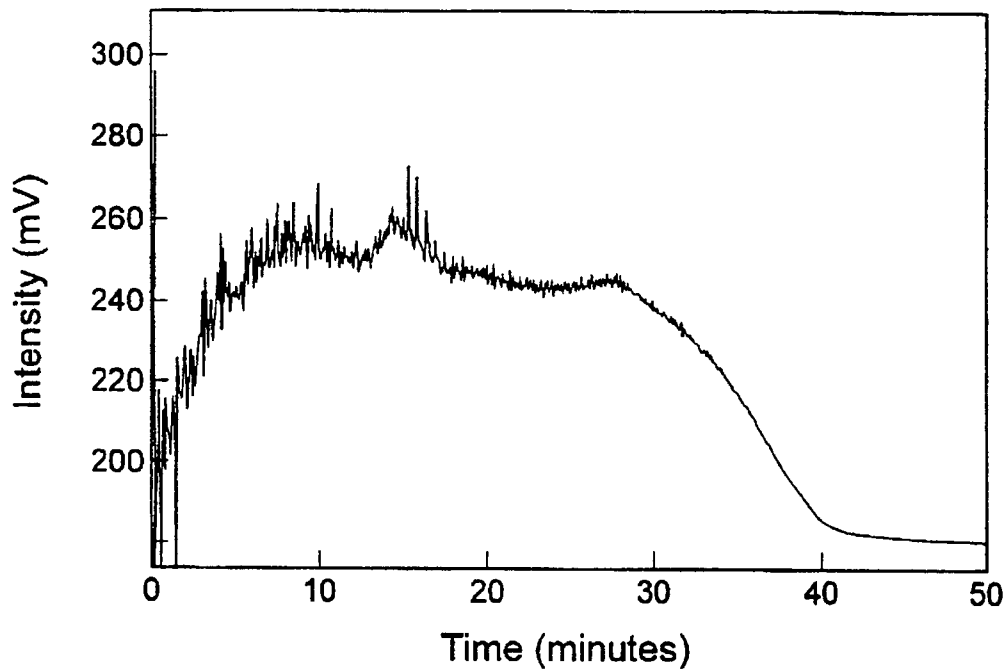
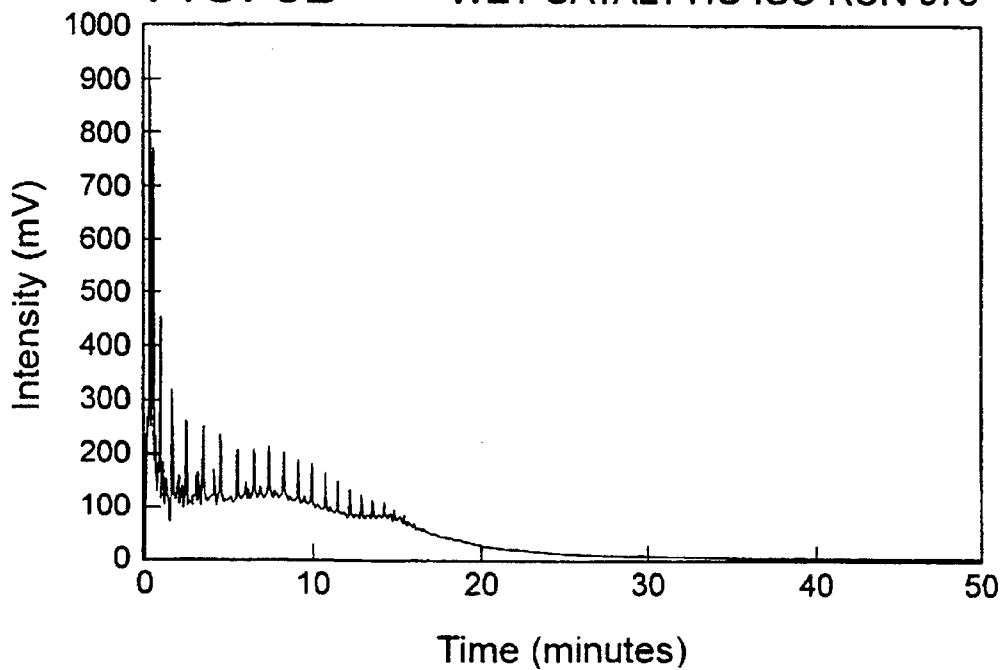


FIG. 5B

WET CATALYTIC ISC RUN 976



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FIG. 6

UPSTRUCTURE FAULT

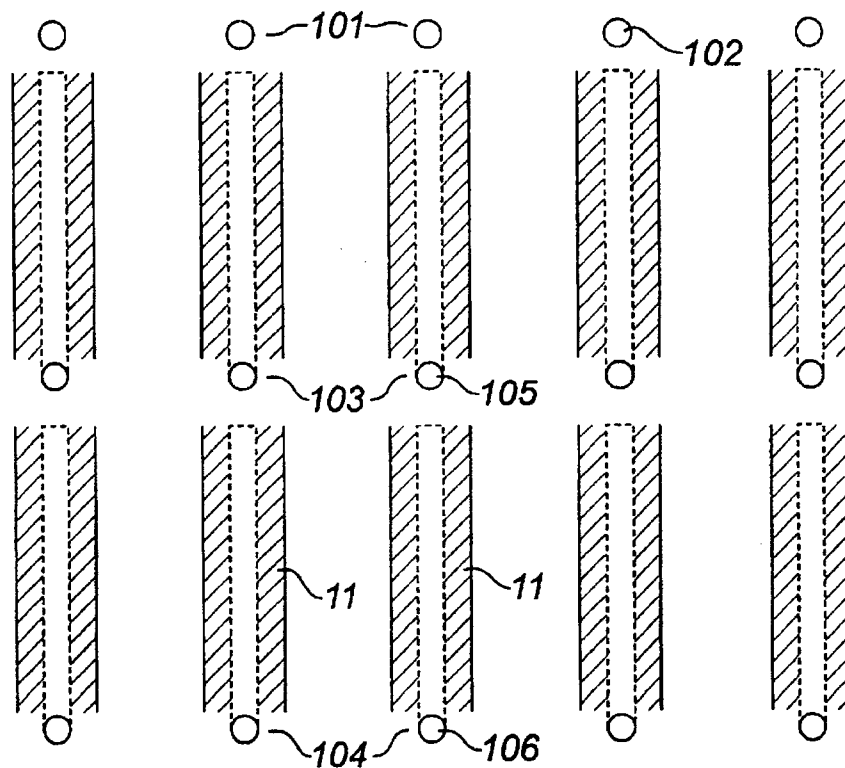


FIG. 7

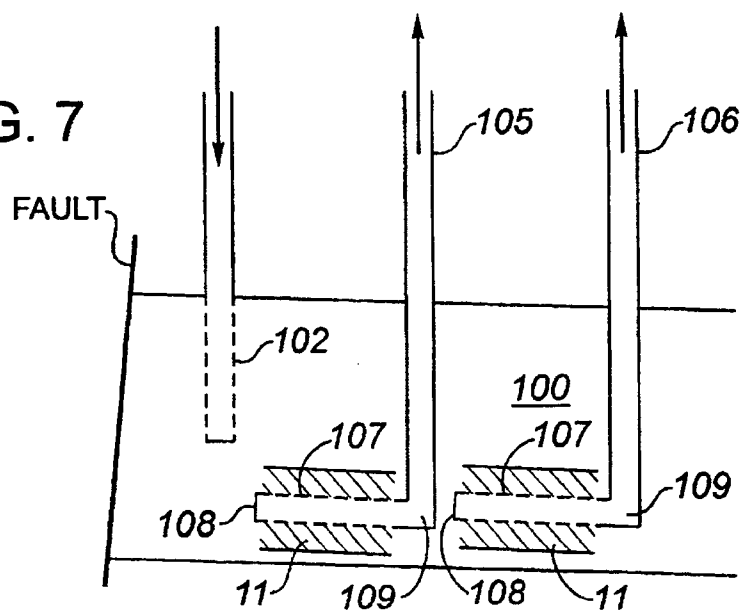


FIG. 8A

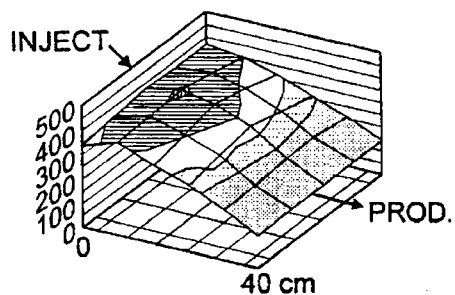


FIG. 8B

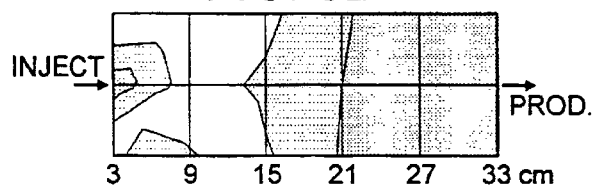


FIG. 8C

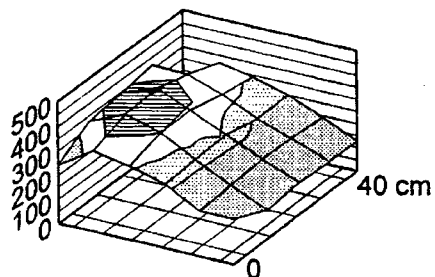


FIG. 8D

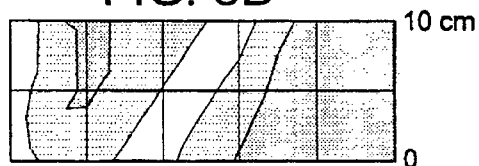


FIG. 8E

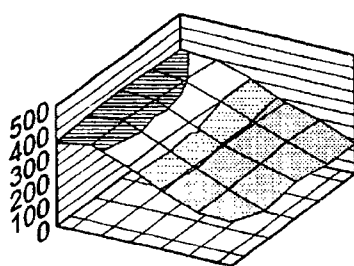
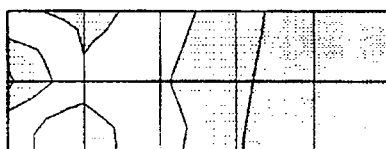


FIG. 8F



OILFIELD IN SITU HYDROCARBON UPGRADING PROCESS

This application claims benefit of provisional application No. 60/069,182 filed Dec. 11, '97

FIELD OF THE INVENTION

This invention relates to a catalytic in situ process for upgrading hydrocarbons in an underground reservoir. More particularly, it relates to a process in which a catalyst is placed along the horizontal segment of a horizontal production well operating in a toe-to-heel configuration, which enables carbon monoxide and/or hydrogen produced in the reservoir or injected into the reservoir with steam, to pass sequentially with reservoir oil over the catalyst, immediately prior to being produced.

BACKGROUND OF THE INVENTION

Large supplies of heavy oil (ca. 8 to 15 degrees API) and medium oil (ca. 15-25 API) exist throughout the world, most notably in Venezuela, Canada and the U.S.A. Significant deposits are also to be found in the North Sea, China and Romania. The composition of the crude oil barrel is inexorably moving towards this heavier material, but it is relatively uneconomic to produce. Without upgrading to produce an oil of lighter composition, i.e. containing more white oil distillates (gasoline, diesel, etc.), heavy oil has very limited potential, historically trading at around \$9.00 below the price of conventional oil. While surface upgrading technology (H-Oil, Vega-Combi or LC Fining processes) is possible, the payout time on the very large investment required is long (ca. ten years), which is discouraging to commercialization.

In situ oil upgrading has several advantages over conventional surface upgrading technologies. Because in situ upgrading (reaction occurring underground) can be implemented on a well-by-well basis, there is no need for large capital-intensive projects. Rather, the size of an in situ project for a particular field can be tailored to available production rates. Thus, in situ upgrading is practical even for those fields deemed too small to provide sufficient production for conventional surface upgrading processing. Additional advantages for in situ upgrading include the production of a more desirable and valuable product, ease in shipping and pipelining (minimum of 22 degree API gravity), and less demanding downstream processing (processable by a conventional refinery).

The requirements for an in situ upgrading process include: provision or a downhole bed of catalyst, achievement of appropriate high reaction temperatures and pressure at the catalyst bed, and mobilization of oil and co-reactants over the catalyst. Although the technologies to accomplish each of these tasks separately are known, their combination into a unified effective underground process has yet to be demonstrated in practice.

Because it is the most efficient method to achieve high temperatures in a reservoir without the direct application of heat, in situ combustion (ISC) is a promising oil recovery process to exploit in the development of an efficient and economical in situ upgrading process.

In-situ combustion processes are applied for the purpose of heating heavy or medium oil to mobilize it and drive it to an open production well for recovery. In general, the usual ISC technique used involves providing spaced apart vertical injection and production wells completed in a reservoir. Typically, an injection well will be located within a pattern

of surrounding production wells. Air, or other oxygen-containing gases are injected into the formation. The mixture of air or oxidizing gas and hydrocarbons is ignited, a combustion front is generated in the formation and the resulting combustion front is advanced outwardly toward the production wells. Or, alternately, a row of injection wells may feed air to a laterally extending combustion front which advances as a line drive toward a parallel row of production wells.

In both cases the operator seeks to establish an upright combustion front which provides good vertical sweep and advances generally horizontally through the reservoir with good lateral sweep. However the processes are not easy to operate and are characterized by various difficulties. One such difficulty arises from what is referred to as gravity segregation. The hot combustion gases tend to rise into the upper reaches of the reservoir. Being highly mobile, they tend to penetrate permeable streaks and rapidly advance preferentially through them. As a result they fail to uniformly carry out, over the cross-section of the reservoir, the functions of heating and driving oil towards the production wells. The resulting process efficiency therefore is often undesirably low. Typically the volumetric sweep efficiencies are less than 30%.

Weissman et al (Energy and Fuels. 1996, 10.883,889) have recently proposed a modified in situ combustion process using a vertical well production strategy, in which a catalyst bed is emplaced around the production well. They have reported the results of two ISC tests, from which they concluded that a heated bed of hydrocracker catalyst placed in the bottom section of an 1.8 m long, 0.1 m diameter combustion tube (a special thin-walled reactor to simulate reservoir conditions), was effective in converting carbon monoxide, produced at the combustion front, and water, into carbon dioxide and hydrogen, via the water gas shift reaction. Not only was 50% of the sulphur removed by hydrosulfurization ("HDS"), but there were also decreases in the oil density and viscosity obtained by the catalytic reaction. However, there were two main problems foreseen with this process: (1) the high retention of oil in the catalyst bed/gravel-pack (a large, one-place volume, with a vertical producer well), would lead to severe coking of the catalyst; and 2) the need to operate in either a cyclic mode (backflow on the injector well), or with a severe gas override condition to provide heat to the catalyst bed. Both processes possibly require supplementary downhole heating, which is both expensive and risky. Also, very importantly, the extremely acidic process gases (carbon dioxide and sulfur dioxide) entering the vertical production well, in combination with a temperature of over 300 degrees Celsius, will cause severe corrosion to the vertical well, through which all production fluids must pass. In the case of deliberate combustion-gas override (which is used to achieve high temperatures at the vertical well), very poor reservoir sweep will be achieved and the possibility of oxygen breakthrough is increased, which could cause a serious explosion hazard. In the case that the proposed cyclic combustion process is used (again to achieve high temperatures at the vertical production well), the production rates will be at least halved because of the required air injection time in the same well. In summary, the two proposed catalytic in situ processes appear expensive and difficult to operate, and so are not felt to be feasible.

A new viscous oil recovery process has recently been developed which provides a substantial increase in reservoir sweep efficiency over that of the traditional ISC process. A combination of wells is used wherein the toes of horizontal production wells are the first segments to provide hydrocar-

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bon production and to come into contact with the injected gases. Greaves and Turta, in U.S. Pat. No. 5,626,191, disclose such a well configuration, which they call the "toe-to-heel" oil displacement process. The patent applies to any process where gases are injected to reduce the viscosity of oil in an underground reservoir, and includes oxidizing gases for in situ combustion, steam injection, steam injection along with other gases, and hydrocarbon solvent gases.

Many oilfield operators are reluctant to apply the in situ combustion process because of historically poor performance when used in a traditional vertical well drive mode, and so an in situ upgrading process that uses steam would be more appealing. Since some heavy or medium gravity oil reserves are found in relatively deep and hot reservoirs, for example in the Orinoco Belt in Venezuela, high temperature steam can be utilized to provide the heat for an in situ upgrading process in some cases.

In summary of the prior art, it has been recognized as very desirable to achieve oil upgrading in an underground reservoir and the ISC process has been proposed as a possible heat source, but an effective process for implementing these steps has not yet been developed. The work underlying the present invention was undertaken to reach this objective. The present invention will now be described.

SUMMARY OF THE INVENTION

Considering the disclosure of U.S. Pat. No. 5,626,191 of Greaves and Turta that:

1. if a generally linear and laterally extending, upright combustion front is established and propagated high in an oil-containing reservoir; and
2. if an open production well is provided having a horizontal leg positioned low in the reservoir so that the well extends generally perpendicularly to and lies in the path of the front and has its furthest extremity ("toe") spaced from but adjacent to the injection sources; then
3. the production well will provide a low pressure sink and outlet that functions to induce the lateral sweep front to advance in a guided and controlled fashion, first intersecting the toe and then proceeding along the length of the horizontal leg - under these circumstances, the oil displacement front will remain generally stable and upright and be characterized by a relatively high reservoir sweep efficiency; and
4. the unreacted injectant gases and reaction gases will flow through the swept portion of the reservoir and through the vertical reaction front and react with the oil at the front. Streamlines of the gases will bend towards the horizontal leg, due to the downward flow gradient created by the action of the production well as a sink, but will also rise due to gravity phase segregation, resulting in a net vertical front advancing laterally without significant over-riding. In the case of steam injection, the condensed water and heated oil will, along with any gases present, likewise flow down to the low pressure sink. In the case of in situ combustion the gases will be combustion gases: carbon monoxide, carbon dioxide, sulphur dioxide and water vapor.

Now, in accordance with the present invention:

if an appropriate oil upgrading catalyst is placed along the horizontal leg of a production well arranged in toe-to-heel configuration, including any of within the leg, on the leg or in the reservoir around the leg; then

hot combustion gases from an ISC process, or steam from a steam injection process combined with injected

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reducing gases, such as carbon monoxide or hydrogen, will react with the commingled oil over the catalyst at appropriate temperature and pressure and the oil will be substantially upgraded.

When compared in experimental runs with a conventional toe-to-heel ("TTH") in situ combustion process in accordance with the Greaves and Turta patent, without catalyst in the vicinity of the horizontal leg of the oil producing well, the present invention was found to be relatively characterized by:

- increased average API gravity of produced oil;
- reduced oil viscosity;
- reduced oxygen and carbon monoxide and increased carbon dioxide levels in the produced gas stream;
- extensive hydrodesulfurization of the oil; and
- extensive hydrodemetallization of the oil.

Additionally, the present process benefits from being a single pass catalytic process so that the reactant oil and gases continuously access fresh catalyst. The distributed catalyst along the horizontal well maintains high conversion activity by virtue of sequential catalyst exposure caused by the advancing movement of the combustion front from the toe to the heel of the horizontal well.

Therefore, in broad terms, the invention is a process for upgrading oil in an underground reservoir while the oil is recovered through a production well, comprising: providing an injection well for injecting a gaseous fluid into the reservoir to form an advancing, laterally extending displacement front operative to reduce the viscosity of reservoir oil; providing at least one open production well having a horizontal leg completed relatively low in the reservoir and positioned substantially perpendicular to and in the path of the advancing front; emplacing oil upgrading catalyst along the leg's length; injecting the gaseous fluid into the injection well and advancing the displacement front along the leg; and producing the production well to recover upgraded oil from the reservoir.

DESCRIPTION OF THE DRAWINGS

FIG. 1 is a perspective view schematically showing a sand pack with simulated vertical injection wells and a perpendicularly arranged, horizontal production well, said injection wells and production well being completed relatively high and low in the pack, respectively, as in the base case of the Greaves and Turta prior art, and reported below for Runs 971 and 972;

FIG. 2 is a perspective view schematically showing a sand pack with simulated vertical injection wells and a perpendicularly arranged, horizontal production well, said injection wells and production well being completed relatively high and low in the pack, respectively, as in FIG. 1, but with the placement of upgrading catalyst around the horizontal segment of the horizontal well, and reported below for Runs 975 and 976;

FIGS. 3a, 3b, 3c are top, side and end views of the test cell employed in demonstration of the present invention for the toe-to-heel process when operated in the catalytic upgrading mode in Runs 975 and 976;

FIG. 4 is a flow diagram showing the laboratory set-up, including the test cell of FIGS. 3a-3c, used to conduct the experimental runs reported on below;

FIGS. 5a and 5b show gas chromatographic spectra for Wolf Lake crude oil used in the test runs, and produced oil from the catalytic wet ISC Run 976 of the present invention, respectively;

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FIG. 6 is a plan view showing a preferred field embodiment of the well layout;

FIG. 7 is a side cross-section taken along the line XII—XII of the well arrangement of FIG. 6; and

FIGS. 8a, 8c and 8e are horizontal thermal contour plots for three layers in the sand pack after 6 hours of operation during Run 7—FIGS. 8b, 8d and 8f are vertical cross-section thermal contour plots.

DESCRIPTION OF THE PREFERRED EMBODIMENT

The invention was developed in the course of carrying out an experimental investigation involving test runs carried out in a test cell or three dimensional physical model.

More particularly, a test cell 1, shown in FIGS. 3a, 3b and 3c was provided. The cell comprised a rectangular, closed, thin-walled stainless steel box 2. Dimension-wise, the box 2 formed a chamber 3 having dimensions 40×40×10 cm (total volume 16,000 c.c.). The thickness of each box wall was 4 millimeters. The chamber 3 was filled with a sand pack 4 consisting of a mixture of sand, clay, oil and water. The composition of the uniform mixture charged into the chamber 3 and other bed properties shown below in Table 1.

The porosity of the sand pack 4 was about 38.5% and the permeability was about 1.042 darcys.

The loaded cell box 2 was placed inside a larger aluminum box 5 and the space between them was filled with vermiculite powder insulation.

Sixty type K thermocouples 6, positioned at 6 cm intervals as shown in FIGS. 3a, 3b, 3c and 4, extended through the wall of the cell 1 into the sand pack 4, for measuring the three dimensional temperature distribution in the sand pack 4.

To compensate for heat losses, the cell 1 was wound with heating tape (not shown). This heat source was controlled manually, on demand, in response to the observed combustion peak temperature and adjacent well temperature values. The temperature at the wall of the cell was kept a few degrees Celsius less than the temperature inside the sand, close to the wall. In this way, the quasi-adiabatic character of the run was assured.

A cell heater 7 was embedded in the top section of the sand pack 4 at the air injection end, for raising the temperature in the region of the injection well 8 to ignition temperature.

Simulated air injection wells 8 were provided at the injection end of the cell 1. A simulated production well 9 was provided at the opposite or production end of the cell 1.

For Runs 975 and 976, a 0.25 inch diameter cylindrical catalyst bed was placed around the horizontal leg, whereas, for Runs 971 and 972, which constitute demonstrations of prior art for comparison purposes, the catalyst bed was omitted.

The positioning and vertical or horizontal disposition of the wells 8, 9 are shown schematically in FIGS. 1, 2 and 3a–3c for the four test runs reported on below. This well configuration is referred to as the direct line drive configuration. However, other well configurations are also contemplated, such as staggered line drive where the vertical injection wells are placed between the horizontal legs, or a horizontal injection well is placed relatively high in the reservoir to simulate the effect of a number of vertical injectors by having periodic perforations as a means to distribute the injectant gas. In the case that the reservoir heating is accomplished by injection of steam, the appropriate

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location of the steam injectors will be reservoir-specific and may not be high in the reservoir.

As shown in FIG. 1 for non-catalytic Runs 971 and 972, a horizontal injection well 8 was placed relatively high in the cell, while the production well 9 was horizontal and placed relatively low in the test cell with its toe slightly displaced from the injection well. Non-catalytic Runs 971 and 972 were a demonstration of prior art (Greaves and Turta) and were conducted for comparison purposes only. Run 971 was a dry ISC process, and Run 972 was a wet ISC process. There was no catalyst present for these Runs.

As shown in FIGS. 2 and 3a–3c, for catalytic Runs 975 and 976, a horizontal injection well 8, positioned laterally across the sand pack 4, was provided. The injection well was located relatively high in the sand pack. The production well 9 was horizontal, elongated, positioned low in the sand pack and had its toe adjacent to but spaced from the injection well. The horizontal production well 9 was arranged to be generally perpendicular to a laterally extending combustion front developed at the injection source. However, the toe 10 of the production well was spaced horizontally away from a vertical projection of the injection well. An elongated ring of catalyst, 11, was placed around the horizontal well 9.

The oil upgrading catalyst employed in Runs 975 and 976 was a standard hydrotreating/HDS catalyst manufactured by Akzo Chemie Nederland bv. Amsterdam, and identified as Ketjenfine 742-1, 3AQ.

Each of the injection and production wells 8, 9 were formed of perforated stainless steel tubing having a bore 4 mm in diameter. The tubing was covered with 100 gauge wire mesh (not shown) to exclude sand from entering the tubing bore.

The combustion cell 1 was integrated into a conventional laboratory system shown in FIG. 4. The major components of this system are now shortly described.

Air was supplied to the injection well 18 from a tank 19 through a line 20. The line 20 was sequentially connected with a gas dryer 21, mass flowmeter 22 and pressure gauge 23 before reaching the injection well 8. Nitrogen could be supplied to the injection well 8 from a tank 24 connected to line 20. Water could be supplied to the injection well 8 from a tank 27 by a pump 25 through line 26. Line 26 was connected with line 20 downstream of the pressure gauge 23. A temperature controller 28 controlled the ignition heater 7. The produced fluids passed through a line 30 connected with a separator 31. Gases separated from the produced fluid and passed out of the separator 31 through an overhead line 32 controlled by a back pressure regulator 33. The regulator 33 maintained a constant pressure in the test cell 1. The volume of the produced gas was measured by a wet test meter 34 connected to line 32. The liquid leaving the separator was collected in a cylinder 40.

Part of the produced gas was passed through an oxygen analyzer 36 and gas chromatograph 37. Temperature data from the thermocouples 6 was collected by a computer 38 and gas composition data was collected from the analyzer 36 and gas chromatograph 37 by an integrator 39.

TABLE 1

Run Code	BED PROPERTIES			
	971	973	975	976
Bed Type	Uncon	Uncon	Uncon	Uncon
Sand Type	Silica. W50	Silica. W50	Silica. W50	Silica. W50

TABLE 1-continued

BED PROPERTIES				
Run Code	971	973	975	976
Sand wt %	97	97	97	97
Clay wt %	3	3	3	3
kaolinite				
Porosity %	38.5	38.5	38.5	38.5
Permeability (md)	1042	1042	1042	1042
S _{oi} %	76	76	76	76
S _{wi} %	17	17	17	17
S _{gi} %	7	7	7	7
Initial Temperature (Deg C.)	18	17	18	17

Air was injected at a rate of approximately 6.0 l/m. and ignition was initiated using the heater 7. The tests were typically continued for up to 11 hours for the dry ISC Runs 971, 975 and for 7.5 hours for the wet ISC Runs 972, 976. In the runs where water was added, its rate was 0.025 l/m. Details of the operating conditions are provided in Table 2.

TABLE 2

OPERATING CONDITIONS				
Run Code	971	972	975	976
Combustion Mode	Dry	Wet	Dry	Wet
Catalyst	no	no	yes	yes
Air flux (m ³ /m ² · hr)	9	9	9	9
Oxygen flux (m ³ /m ² · hr)	1.89	1.89	1.89	1.89
Air Injection Rate (l/min)	6	6	6	6
Water Air Ratio (m ³ /m ³)	0	0.0042	0	0.0042
Water injection rate (l/min)	0	0.025	0	0.025
Initial Temperature (Deg C.)	18	17	18	17
Operating pressure (psig)	25	25	25	25
Well Type	HI-HP	HI-HP	HI-HP	HI-HP
Well Configuration	Line Drive	Line Drive	Line Drive	Line Drive
Back pressure set point (psig)	24.4	24.3	24.5	24.4

Legend

HI=Horizontal Injector

HP=Horizontal Producer

Following completion of each run, an analysis of the cell sand pack 4 was undertaken to determine the volumetric sweep efficiency. The analysis comprised a physical removal of successive vertical layers of the sandpack at 3 cm intervals and determining the extent of the burned zone by measuring the oil and coke content. In this way the volumetric sweep of the burning front was determined postmortem and compared with that obtained from the peak temperature profiles during the run. The results of the four Runs are set forth in Table 3.

TABLE 3

SUMMARY OF RESULTS				
Run Code	971	972	975	976
Combustion Mode	Dry	Wet	Dry	Wet
Catalyst?	no	no	yes	yes
Overall period (hrs)	12.7	7.5	12.5	7.3
Pre-ignition period (hrs)	1.98	2.00	2.30	1.98
Air injection period (hrs)	10.7	5.5	10.2	5.3
Dry phase period (hrs)	10.7	2.4	10.2	2.6
Wet phase period (hrs)	0	3.1	0	2.7
Peak temp (dry phase) (deg C.)	621	625	629	627
Stabilized temp (dry phase) (deg C.)	452	455	455	451
Peak temp (wet phase) (deg C.)	N/A	477	N/A	468
Stabilized temp (wet phase) (deg C.)	N/A	393	N/A	402
CO ₂ % (dry stabilized)	14.3	14.2	16.5	16.5
CO % (dry stabilized)	4.0	4.0	2.4	2.3
O ₂ % (dry stabilized)	1.10	1.18	0.85	0.93
CO ₂ % (wet stabilized)	N/A	13.9	N/A	17.1
CO % (wet stabilized)	N/A	3.5	N/A	0.3
O ₂ % (wet stabilized)	N/A	2.3	N/A	1.6
H ₂ % (calculated for 975 & 976)	N/A	N/A	1.9	5.8
CO/CO + CO ₂	0.220	0.200	0.130	0.017
H/C	0.73	0.71	0.44	0.33
Air to Fuel requirements (Sm 3/kg)	9.485	9.544	9.457	9.810
O ₂ to fuel requirements (Sm 3/kg)	2.00	2.00	2.00	2.06
Fuel burned (kg)	0.384	0.186	0.371	0.181
Fuel burned (% of OOIP)	9.10	4.40	8.74	4.27
Oxygen utilization % (Average)	94.8	89.0	96.0	92.3
Volumetric sweep efficiency %	40.7	43.0	39.0	38.7
Fuel combustion (kg/m ³)	65	30	65	32
Air Oil ratio (m ³ /m ³)	1328	744	1428	738
Water Air ratio (m ³ /m ³)	0	0.0042	0	0.0042
Oil recovery % of OOIP	67.9	62.3	60.4	53.2
Water recovery % of OOIP	91.3	80.4	71.1	69.8
Combustion front velocity (m/hr)	0.016	0.024	0.015	0.022

The produced gas analyses provide support for occurrence of the water gas shift reaction in the catalyst zone. The reaction is: $\text{CO} + \text{H}_2\text{O} = \text{CO}_2 + \text{H}_2$. Comparing the non-catalytic and catalytic dry ISC Runs, 971 and 975 respectively, the CO produced gas is 40% lower for the catalytic case (2.4% vs 4.0%).

Comparing the produced CO for the wet combustion cases, Runs 972 and 976, the CO level is 91% lower when catalyst is present (0.31% vs 3.50%).

The CO₂ levels are higher in the two catalyst Runs 975 and 976, compared with the corresponding non-catalytic Runs 971 and 972, which provides further support for the water gas shift reaction as a primary source of hydrogen in catalytic in situ upgrading.

The differences in recovery of the original water in place can be used to calculate the amount of hydrogen produced and consumed during in situ upgrading reactions; the result is 1.91% of the total produced gas phase for Run 975 dry catalytic ISC, and 5.8% for wet catalytic ISC Run 976.

The results described above make it clear that any catalyst that has water gas shift activity would be beneficial and could be employed by itself or in any proportion in admixture with the hydrotreating/HDS catalyst used in Runs 975 and 976 or other such catalyst.

Since the water gas shift reaction produces the hydrogen required for oil upgrading, the process can be carried out by injecting high temperature steam and carbon monoxide. A carbon monoxide source, for example, oxygen-starved combustion of natural gas, will produce a gas elevated in CO which can be injected into the reservoir. In this way the key ingredients for effective in situ upgrading will be provided: these are heat, hydrogen and active catalysts.

Also to be noted as a benefit of catalytic ISC is the lower level of produced oxygen. Since each pair of non-catalytic and catalytic Runs were conducted under the same conditions, the oxygen reduction can be attributed to the presence of catalyst.

The analyses of produced oil are presented in Tables 4 and 5 for API gravity, density and viscosity at each half-hour interval.

The prior art toe-to-heel ISC process of Greaves and Turta provides considerable thermal upgrading as measured by the three aforementioned parameters (Runs 971 and 972), but still fall very short of the performance of the catalytic Runs 975 and 976 of the present invention. The average results are summarized in Table 6. Wet catalytic ISC improved the oil gravity from 11.0 API to 20.7 API and reduced the viscosity from 100,000 cps to 46 cps. Therefore the upgraded oil at a viscosity of 46 cps will be easily pipelined without the need for a diluent. Since diluent light hydrocarbons are expensive and in short supply this is a valuable benefit of the present invention.

TABLE 4

DRY NORMAL AND CATALYTIC						
Run 971 (Dry Normal)				Run 975 (Dry Catalytic)		
Time	API	Density	Viscosity	API	Density	Viscosity
0.5	11.0	0.993	100000	11.0	0.993	100000
1	11.0	0.993	100000	11.3	0.991	97780
1.5	11.0	0.993	100000	14.2	0.971	8220
2	11.1	0.992	98873	14.6	0.969	7830
2.5	12.4	0.983	20234	20.6	0.930	40
3	12.8	0.981	14060	20.5	0.931	43
3.5	15.3	0.964	7435	19.8	0.935	62
4	14.8	0.967	7675	19.5	0.937	68

TABLE 4-continued

DRY NORMAL AND CATALYTIC						
Run 971 (Dry Normal)				Run 975 (Dry Catalytic)		
Time	API	Density	Viscosity	API	Density	Viscosity
4.5	14.5	0.969	8020	19.3	0.938	74
5	14.1	0.972	8430	19.2	0.939	82
5.5	14.3	0.971	8160	18.9	0.941	97
6	14.0	0.973	8570	18.6	0.943	104
6.5	13.8	0.974	9010	18.4	0.944	111
7	13.7	0.945	9035	18.3	0.945	117
7.5	13.9	0.973	8660	18.2	0.945	123
8	14.0	0.973	8550	18.5	0.943	106
8.5	13.8	0.974	8990	18.0	0.946	133
9	13.6	0.975	9050	18.3	0.945	118
9.5	13.2	0.978	9780	18.4	0.944	110
10	13.4	0.977	9580	18.2	0.945	123
10.5	13.5	0.976	9440	18.3	0.945	118
11	13.3	0.977	9630	18.1	0.946	129
11.5	13.4	0.977	9560	18.0	0.946	132
12	13.1	0.979	9820	18.3	0.945	118
12.5	13.2	0.978	9770	18.4	0.944	109
Average (3.5-12.5 hrs)	13.8	0.972	8903	18.7	0.948	101

TABLE 5

WET NORMAL AND CATALYTIC						
Run 971 (Dry Normal)				Run 975 (Dry Catalytic)		
Time	API	Density	Viscosity	API	Density	Viscosity
0.5	11.0	0.993	100000	11.0	0.993	100000
1	11.0	0.993	100000	11.7	0.988	95760
1.5	11.0	0.993	100000	13.4	0.977	10043
2	11.2	0.967	99020	15.1	0.965	6320
2.5	14.8	0.971	7690	19.8	0.935	65
3	14.2	0.975	8210	20.4	0.932	46
3.5	13.7	0.976	9015	19.7	0.936	63
4	13.5	0.974	9460	19.6	0.936	65
4.5	13.8	0.977	9000	19.4	0.938	72
5	13.4	0.977	9560	22.2	0.930	24
5.5	13.2	0.978	9760	20.7	0.921	37
6	12.5	0.983	10170	21.4	0.925	31
6.5	13.0	0.979	9900	20.7	0.930	37
7	12.9	0.980	9960	21.0	0.928	33
7.5	12.8	0.981	10040	21.3	0.926	32
Average (2.5-7.5 hrs)	13.4	0.980	9342	20.6	0.931	46

TABLE 6

SUMMARY OF UPGRADING RESULTS (AVERAGES)				
Run #	Condition	API Gravity	Density g/cc	Viscosity mPa · s
Base	no ISC	11.0	0.993	100,000
971	Dry Normal	13.8	0.972	8,903
975	Dry Catalytic	18.7	0.948	101
972	Wet Normal	13.4	0.980	9,342
976	Wet Catalytic	20.7	0.931	46

Further important upgrading benefits are demonstrated in Table 7, where XT004466 is clean dry Wolf Lake crude oil which was used in the four test Runs 971, 972, 975 and 976, and XT004467 is produced oil from the wet catalytic Run 976 of the present invention.

An extensive desulfurization and demetalization of the base oil was achieved in the catalytic Run 976 of the present invention. Sulfur was reduced 88% from 43,400 ppm to

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5,100 ppm; nickel 96% from 73 ppm to 3 ppm and vanadium 96% from 195 ppm to 8 ppm. Other metals, such as iron and molybdenum were also partially removed in the catalytic process. It should be noted that the increase in silicon is not a consequence of the presence of catalyst: all high temperature steam processes give rise to elevated silicon levels.

TABLE 7

OIL SULFUR AND METAL ANALYSIS (by ICP, mg/kg)		
Sample ID	XT004466 (10 API)	XT004467 (20.7 API)
Customer ref:	Base Wolf Lake oil	Run 976 product
Silver	<1	<1
Aluminum	<1	<1
Boron	2	3
Barium	<1	<1
Calcium	2	2
Chromium	<1	<1
Copper	<1	<1
Iron	5	<1
Potassium	<8	<8
Magnesium	1	<1
Manganese	<1	<1
Molybdenum	7	3
Sodium	<6	<6
Nickel	73	3
Phosphorus	<2	<2
Lead	<2	<2
Sulphur	43400	5100
Silicon	1	69
Tin	<2	<2
Titanium	1	<1
Vanadium	195	8
Zinc	2	5

FIG. 5 shows gas chromatographic analyses of samples XT 004466 Wolf Lake crude oil and Run 976 wet catalytic ISC product. Very extensive oil upgrading is apparent from the large decrease in heavy components observed in the catalytic Run.

The wet combustion test of Run 976 demonstrated the preferred form of the invention. Either moderate wet combustion or superwet combustion may be applied. However, in oil reservoirs where water injectivity is too low, the catalytic dry combustion process may be applied as well. Test of NCC Type Catalyst

Run 986 was conducted using NCC catalyst placed around the horizontal leg of the producer for the purpose of comparison with an otherwise identical non-catalytic Run 985.

The original test cell was modified to have 6-band heaters and computer control to provide a better approach to adiabatic conditions.

The catalytic Run 986 used the catalyst FCC-RESOC-1 BU, a rare earth alumino silicate supplied by Grace Davison, and having the following physical characteristics.

Composition	42% Al ₂ O ₃ , 1.0% Rare Earth oxide, 0.2% Na ₂ O
Surface area (square meters/gm)	300
Bulk density (g/ml)	0.7
Average particle size (microns)	72

Results showed that the Run 986 with NCC catalyst produced Wolf Lake oil (11 API) of 21.0 degrees API, which was 7 degrees API higher than the thermally cracked oil in the absence of catalyst in Run 985.

The effect of vertical heterogeneity of the reservoir on fluid channeling was tested in a specially-packed cell in Run

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7. Three layers of sand were packed sequentially using fine, coarse and fine-grained sands to see whether air would advance ahead of the vertical combustion front in the high-permeability central layer. Table 8 gives the details of the stratified model. FIGS. 8a-8f shows the results in terms of thermal contours. The vertical axis represents temperature in all cases. Lowest temperatures are shown in dark color. The combustion front remained substantially vertical, with no preferred advancement into the central zone. The explanation may be that the vertical drainage of the hot cracked oil provides a "self-healing" phenomenon where air advancement into the central high permeability streak is blocked by draining oil. This demonstrates that the process of the present invention has a major advantage over processes of the prior art in which both the injected air and produced fluids flow substantially horizontally between vertical wells and fingering of air into high permeability layers causes early oxygen breakthrough and safety hazards. Layers of varying permeability are a very common feature of clastic reservoirs and often prohibits the use of traditional in situ combustion as an oil recovery process. The present invention removes this limitation.

TABLE 8

RUN 7 DRY IN SITU COMBUSTION IN A STRATIFIED MODEL; CLAIR OIL, 19.8 API, 200 CPS AMBIENT		
Layer	Sand Grain Size	Permeability MD
Top	fine	616
Middle	coarse	3000
Bottom	fine	616

In the preferred field embodiment of the invention, the direct line-drive application illustrated in FIGS. 6 and 7, a reservoir 100 is characterized by a downward dip and lateral strike. A row 101 of vertical air-water injection wells 102 is completed high in the reservoir 100 along the strike. At least two rows 103, 104 of production wells 105, 106 having generally horizontal legs 107, are completed low in the reservoir and down dip from the injection wells, with their toes 108 closest to the injection wells 102. The toes 108 of the row 103 of production wells 105 are spaced down dip from a vertical projection of the injection wells 102. Catalyst particles are emplaced along the horizontal well by a well-known operation called "gravel packing". The second row 104 of production wells 106 is spaced down dip from the first row 103, and is similarly gravel packed. Generally, the distance between wells, within a row, is considerably lower than the distance between adjacent rows. In the first phase of the process, a generally linear combustion front is generated in the reservoir 100 by injecting air or air-water through every second well 102. Preferably a generally linear lateral combustion front is developed by initiating combustion at every second well and advancing these fronts laterally until the other wells are intercepted by the combustion front and by keeping the horizontal production wells closed. Then, air is injected through all the wells 102 in order to link these separate fronts to form a single front. Only during this initiation phase of the field exploitation process, and only once in the lifetime of a producing reservoir, is non-upgraded oil produced. The front is then propagated by injecting air and water down dip toward the first row 103 of production wells 105. The horizontal legs of the production wells 105 are generally perpendicular to the front. The production wells 105 are open during this step, to create a

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low pressure sink to induce the front to advance along their horizontal legs 107 and to provide an outlet for the heated oil. When the front approaches the heel 109 of each production well 105, the well is closed in. The horizontal legs 106 (107) of the closed-in wells 105 are then filled with cement. The wells 105 are then perforated high in the reservoir 100 and converted to air-water injection, thereby continuing the propagation of a combustion front toward the second row 104 of production wells 106. Preferably, the first row 101 of injection wells is converted to water injection for scavenging heat in the burnt out zone and bringing it ahead of the combustion zone. This process is repeated as the front progresses through the various rows of production wells. By the practice of this process, a guided combustion front is caused to move through the reservoir with good volumetric sweep efficiency, and the production of upgraded oil.

The embodiments of the invention in which an exclusive property or privilege is claimed are defined as follows:

1. A process for upgrading hydrocarbons in-situ in an underground reservoir having hydrocarbons, comprising the steps of:

- (a) providing at least one injection well for injecting an oxidizing gas into the underground reservoir;
- (b) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;
- (c) providing an oil upgrading catalyst between the toe portion and the heel portion substantially coextensive with at least a portion of the horizontal leg;
- (d) injecting the oxidizing gas through the injection well for in-situ combustion, so that combustion gases are produced;
- (e) thermally upgrading the hydrocarbons in a first in-situ upgrading phase of the process, wherein the combustion gases initially contact the hydrocarbons in the vicinity of the toe portion of the horizontal leg;
- (f) catalytically upgrading at least a portion of the hydrocarbon thermally upgraded in step (e) in a second in-situ upgrading phase of the process, wherein at least a portion of the hydrocarbons thermally upgraded in step (e) and at least a portion of the combustion gases initially contact the oil upgrading catalyst in the vicinity of the toe portion of the horizontal leg; and
- (g) progressively thermally and catalytically upgrading hydrocarbons, wherein
 - (i) the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in a direction from the toe portion to the heel portion and
 - (ii) the oil upgrading catalyst is progressively consumed substantially in a direction from the toe portion to the heel portion of the horizontal leg.

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2. The process of claim 1 wherein the oil upgrading catalyst is provided in packing around the horizontal leg of the production well.

3. The process of claim 1 wherein the horizontal leg of the production well is coated with the oil upgrading catalyst.

4. The process of claim 1 wherein the oil upgrading catalyst is provided in packing inside the horizontal leg of the production well.

5. The process of claim 1 wherein the oil upgrading catalyst comprises a hydrodesulfurizing catalyst.

6. The process of claim 1 wherein a water-gas shift catalyst is used in combination with the oil upgrading catalyst.

7. The process of claim 1 wherein the oxidizing gas comprises air.

8. The process of claim 1 wherein a reducing gas is injected through the injection well.

9. The process of claim 8 wherein the reducing gas is selected from carbon monoxide, hydrogen and a combination thereof.

10. The process of claim 1 wherein a substantially linear array of substantially vertical injection wells is used for injecting oxidizing gas.

11. The process of claim 10 wherein the reservoir extends downwardly at an angle to have a dip and a strike, the injection wells extend generally along the strike and the horizontal leg of the production well extends generally along the dip.

12. The process of claim 10 wherein the reservoir extends downwardly at an angle to have a dip and a strike, a plurality of production wells, each connected to horizontal legs, are provided in at least two spaced apart rows parallel with the array of injection wells, and the rows of injection wells and production wells extend generally along the strike and the horizontal legs of the production wells extend generally along the dip.

13. The process of claim 12 wherein the wells are arranged in a staggered line.

14. The process of claim 12 wherein the wells are arranged in a direct line drive configuration.

15. The process of claim 12, further comprising the steps of:

- (h) closing each production well in the first row as the combustion front approaches the heel of its respective horizontal leg;
- (i) filling the horizontal legs of the closed production wells in the first row with cement;
- (j) re-completing the wells relatively high in the reservoir and converting them to injection wells for injecting oxidizing gas; and
- (k) repeating steps (d) through (g).

16. The process of claim 1 wherein the injection well is a horizontal well having a horizontal portion perpendicular to the horizontal leg of the production well.

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United States Patent [19]

Shu

[11] 4,410,042

[45] Oct. 18, 1983

[54] IN-SITU COMBUSTION METHOD FOR
RECOVERY OF HEAVY OIL UTILIZING
OXYGEN AND CARBON DIOXIDE AS
INITIAL OXIDANT

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[51] Int. Cl.³ F21B 43/243

[52] U.S. Cl. 166/261

[58] Field of Search 166/256, 261, 272, 274

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[57] ABSTRACT

An in-situ combustion method for recovering viscous oil from a subterranean, viscous oil-containing formation comprising injecting a mixture of essentially pure oxygen and carbon dioxide into the formation to initiate an in-situ combustion operation followed by injecting essentially pure oxygen.

5 Claims, No Drawings

IN-SITU COMBUSTION METHOD FOR RECOVERY OF HEAVY OIL UTILIZING OXYGEN AND CARBON DIOXIDE AS INITIAL OXIDANT

BACKGROUND OF THE INVENTION

1. Field of the Invention

This invention pertains to the recovery of oil from a subterranean, viscous oil-containing formation utilizing an improved in-situ combustion process.

2. Background of the Invention

In-situ combustion is a common method for recovering viscous crudes or tar sands. The use of high purity oxygen in place of air significantly improves the performance of the in-situ combustion process. The injection of oxygen into a wellbore, however, presents significant hazards and requires safety precautions. Previous work in this regard includes the injection of O_2 through a bottom water zone, as disclosed in U.S. Pat. No. 3,208,519, and the initiation of combustion with air followed by oxygen as disclosed in an article by G. Pusch, Erdol und Kohle-Erdgas-Petrochemie combined with Brennstoff-Chemie, Vol. 30, No. 1, Jan. 1977, pp. 13-25. All these methods use air to establish gas flow. However, it has been found that injection of air increases the viscosity of the oil by 100 times when the oil is contacted by air for two days at 210° F. This increase in viscosity is detrimental to the recovery process. In addition, the inert gaseous nitrogen in the air injected tends to reduce the effective permeability for oil in the reservoir.

My invention proposes a method to initiate the in-situ combustion operation initially using a combustion supporting gas comprising a mixture of essentially pure oxygen and carbon dioxide followed by the use of essentially pure oxygen that eliminates the problem of increasing the viscosity of the oil in the formation using conventional combustion supporting gases such as air, air enriched with oxygen, or oxygen.

SUMMARY OF THE INVENTION

The invention is a method for recovering oil from a subterranean, viscous oil-containing formation penetrated by at least one injection well and a spaced apart production well comprising initiating in-situ combustion by injecting a mixture of essentially pure oxygen and carbon dioxide into the injection well followed by injecting essentially pure oxygen into the formation to support in-situ combustion either immediately after the initiation of combustion or after the combustion front has advanced away from the injection well a distance of at least 30 feet. The amount of carbon dioxide mixed with oxygen for initiation of in-situ combustion is not more than 80%. The use of an oxygen/carbon dioxide mixture to initiate in-situ combustion does not promote degradation in oil viscosity due to oxidation.

DESCRIPTION OF THE PREFERRED EMBODIMENT

In one embodiment of my invention, an in-situ combustion front is established in a subterranean, viscous oil-containing formation such as tar sand deposits by injecting a combustion-supporting gas comprising essentially pure oxygen and carbon dioxide. The oxygen/carbon dioxide mixture is introduced into the formation via at least one injection well to establish an in-situ combustion front and oil is produced from the formation via a spaced apart production well. The amount of

carbon dioxide mixed with the oxygen must not be more than 80% so as not to interfere with the in-situ combustion process. The amount of carbon dioxide may be substantially less than 80%, depending upon the experience of operating personnel in handling high purity oxygen. Once an in-situ combustion front is initiated, or preferably after the combustion front has advanced away from the injection well a distance of at least 30 feet, the mixture of O_2/CO_2 is terminated and essentially pure oxygen is injected into the injection well to support combustion. In a preferred embodiment, after in-situ combustion has been initiated, or preferably after the combustion front has advanced away from the injection well a distance of at least 30 feet, the amount of carbon dioxide injected into the formation along with oxygen is gradually decreased at a controlled rate until the combustion-supporting gas comprises essentially pure oxygen.

The use of a mixture of oxygen and carbon dioxide as the combustion-supporting gas to initiate in-situ combustion does not promote degradation in oil viscosity due to oxidation as is the case with mixtures of oxygen and nitrogen in conventional in-situ combustion processes. In the present process, any increase in oil viscosity due to oxidation is more than offset by a reduction in viscosity due to carbon dioxide dissolution. For example, an Athabasca bitumen with a viscosity of 50,000 cp at 104° F. will have a reduction in viscosity by 100 times, when saturated with carbon dioxide at 600 psia (see Jacobs, F. A., et al., J. Can. Pet. Tech., Oct.-Dec., 1980, pages 46-50). In the latter example, it is disclosed that it requires only 200 scf of carbon dioxide to saturate a barrel of oil at 600 psia. Assuming the oil saturation is 1000 bbls/ac-ft, it requires only 0.2×10^6 scf/ac-ft of carbon dioxide to saturate the oil. After in-situ combustion has been initiated, there is a sufficient amount of carbon dioxide generated in-situ to saturate the oil in the formation so there is no need to continuously inject carbon dioxide during the combustion process. It is noted that the dissolution of the carbon dioxide in the oil reduces the free gas in the reservoir and increases effective oil permeability. In addition, carbon dioxide has a nice fire-extinguishing characteristic which can be conveniently applied in the case of an accidental well-bore ignition.

The oxygen and carbon dioxide may both be stored in liquid form near the injection well or wells. Both materials may be more conveniently pumped in liquid form from separate storage tanks into a vaporizer and then injected into the injection well. The composition of the oxygen/carbon dioxide mixture supplied to the injection well is controlled by sensing and controlling the flow rates of the individual oxygen and carbon dioxide streams by means of a flow controller.

What is claimed is:

1. A method for recovering oil from a subterranean, viscous oil-containing formation penetrated by at least one injection well and a spaced apart production well comprising:
 - (a) initiating an in-situ combustion front in the formation by injecting a combustion-supporting gas comprising a mixture of essentially pure oxygen and carbon dioxide into the injection well and continuing injection of said combustion-supporting gas until said combustion front has advanced a predetermined distance from the injection well, said injected carbon dioxide dissolving

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- in the in place oil thereby reducing its viscosity and increasing effective oil permeability;
- (b) thereafter terminating injection of the mixture of essentially pure oxygen and carbon dioxide and injecting essentially pure oxygen into the injection well to support in-situ combustion; and
- (c) producing oil from the formation via said production well.

2. The method of claim 1 wherein the combustion-supporting gas in step (a) comprises not more than 80% carbon dioxide.

3. The method of claim 1 wherein injection of the mixture of essentially pure oxygen and carbon dioxide is

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continued during step (a) until the combustion front has advanced away from the injection well a distance of at least 30 feet.

4. The method of claim 1 further comprising gradually decreasing the amount of carbon dioxide in said combustion-supporting gas following step (a) until the gas injected comprises essentially pure oxygen.

5. The method of claim 4 wherein the amount of carbon dioxide is gradually decreased when the combustion front has advanced away from the injection well a distance of at least 30 feet.

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United States Patent [19]

Pusch et al.

[11] 4,042,026

[45] Aug. 16, 1977

[54] METHOD FOR INITIATING AN IN-SITU RECOVERY PROCESS BY THE INTRODUCTION OF OXYGEN

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[52] U.S. Cl. 166/258; 166/251; 166/261; 166/262

[58] Field of Search 166/261, 256, 302, 258, 166/303, 251, 262

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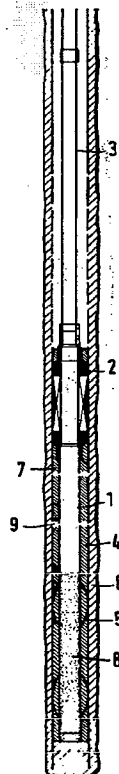
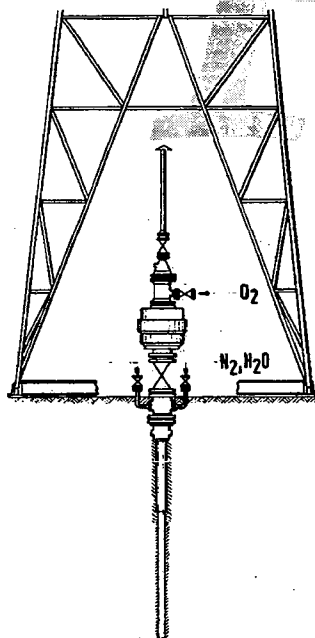
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[57] ABSTRACT

A method for starting a process to recover energy raw materials from a subterranean formation whereby igniters are injected into the upper region of the formation and inert gas is injected into the lower region of the formation, and thereafter an oxygen-containing gas is injected at a predetermined oxygen concentration and rate to initiate combustion, followed by increasing the oxygen concentration and/or rate of the injected gas to a maximum value.

15 Claims, 1 Drawing Figure

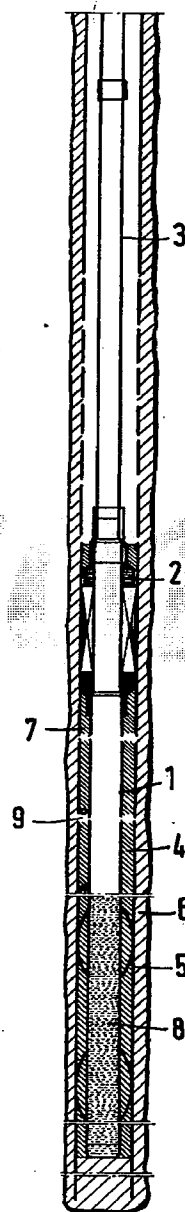
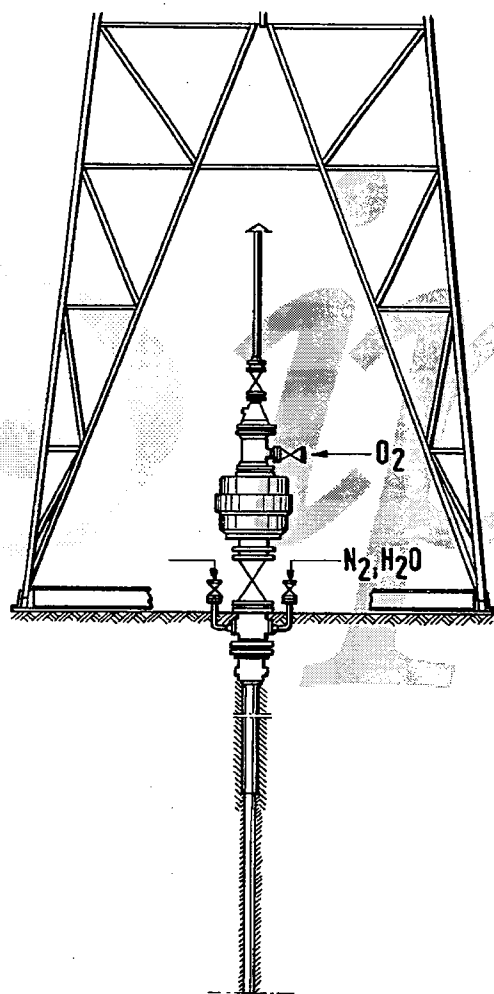


U.S. Patent

Aug. 16, 1977

4,042,026

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4,042,026

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METHOD FOR INITIATING AN IN-SITU RECOVERY PROCESS BY THE INTRODUCTION OF OXYGEN

BACKGROUND OF THE INVENTION

This invention relates to a method for initiating an in-situ recovery process or for starting the operation of the process to recover energy raw materials from a subterranean formation by the introduction of oxygen into the formation.

Since the invention of the underground combustion method for petroleum recovery by F. A. Howard in 1923, a number of methods have been developed, the object of which is the production of heat within the reservoir, especially of sufficient heat, by means of partial combustion of oil residues in a petroleum reservoir to enable recovery of the remaining oil. The most important processes contributing to petroleum displacement are viscosity reduction by means of heat, distillation and cracking of the oil and of the higher boiling components, sweeping out of the oil with hot water and extraction of the oil by means of miscible products. Such a method is specified, for example, in U.S. Pat. No. 3,026,935. Specific modifications of this method require a high oxygen partial pressure in order to bring about miscibility of the carbon dioxide formed during combustion. A high oxygen partial pressure can generally only be obtained by enriching the combustion-supporting gas with oxygen. Oxygen is known to be a gas which reacts readily with almost all substances. The amount of combustion heat released for example in a reaction between oxygen and organic fuels is considerable. On average it amounts to 3000 kcal per kg oxygen.

One of the disadvantages of the use of oxygen is its hazardous nature that could lead to uncontrolled reactions or explosions. Because of the hazardous nature of pure oxygen in reacting with other materials much work has been done to reduce this danger. In addition to the question of reaction of oxygen with various materials the dynamics of compressible fluids is also an important factor in determining what hazard exists when a material is reacted with oxygen.

Great importance is accordingly attached to the structure of the spaces in which the oxygen is flowing. Should said spaces possess a large inner surface in relation to the volume then the danger of an explosion when a fuel and oxygen are reacted is greatly reduced. Consequently the reaction of oxygen with oil contained in the pores of the reservoir rocks poses relatively few problems. However, given certain geometric proportions of the spaces through which the oxygen flows, local temperature peaks can occur, which, although not in accordance with the laws of the dynamics of compressible fluid, cause ignition of the material (steel, plastic, wood etc.).

Finally it is known from experience in autogenous gas cutting that not only the nature of the material but also the composition of the gas used has an influence on the material's cutting quality. With an oxygen content of less than 95%, steel can still be ignited but combustion is not self-sustaining. These ratios apply to atmospheric pressure. However there exists no practical experience with regard to high pressures as found in deep petroleum reservoirs.

If one proceeds from the assumption that the operation of oxygen plants above ground can be considered relatively safe and that the reaction of the oxygen with

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the oil in the reservoir can be controlled, then it follows that the most dangerous point along the oxygen's flow-path is the borehole. The operating conditions in a petroleum borehole are such that when high percentage oxygen is introduced there is a great danger of an explosion in the borehole. Neither is the borehole equipment made from deflagration-proof material (copper, Inconel) nor is the condition of the equipment, due to contact with corrosive, erosive and organic agents, such that the danger is lessened.

It is therefore the objective of this invention to eliminate these risks or at least reduce them to an acceptable level within the framework of conventional equipment used in boreholes for the recovery of energy raw materials such as petroleum hydrocarbons.

BRIEF DESCRIPTION OF THE DRAWING

The accompanying drawing illustrates the method used in the invention.

DESCRIPTION OF THE PREFERRED EMBODIMENT

In order to achieve this objective, a method for starting the operation of a process for subterranean recovery of energy raw materials by introducing oxygen into the penetrated reservoir was developed, characterized in that, igniters known per se are injected into the upper region of the reservoir, that simultaneously an inert gas is injected into the lower region of the reservoir to prevent the igniters penetrating into this region, that subsequently a gas with a predetermined oxygen concentration and a rate of injection is introduced until a corresponding increase in temperature indicates that ignition has taken place and a combustion front is formed, that injection of the gas is continued at the same rate until the combustion front is at a predetermined distance from the injection borehole, whereafter the rate of injection and/or oxygen concentration is increased to a predetermined maximum rate or end concentration, that the oxygen is injected into the reservoir through at least one radially arranged outlet opening with a pressure ratio of flow-in pressure to discharge pressure at the outlet opening of from 1.2 to 2.5 and that simultaneously water is injected into the upper region of the reservoir.

An advantage of this method is that the injection of the igniters and the gases into the reservoir by means of two vertically unconnected regions avoids oxygen and residual oil from the reservoir coming into contact with igniters in the borehole, thereby eliminating the dangerous phase during the injection of oxygen.

A more complete understanding of the performance and advantages of the invention may be had by referring to the drawing. The drawing illustrates a cross-sectional view of a borehole traversing the subterranean reservoir containing the energy raw material.

Packer 2 with Liner 1, made of high-grade steel, is set in the casing and cemented in the borehole. Prepared cement 4, mixed with suitable setting inhibitors, is previously pumped into the borehole up to a specific level. Once packer 2 has been set at the correct height the superfluous cement 4 is circulated off. An injection pipe 3 is screwed into packer 2. This string has a flexible part to equalize tensions resulting from changes in temperature and pressure. Only dry gases are injected through pipe 3. The injection gas is passed from the borehole into the reservoir via openings 9 which have been subsequently perforated through liner 1, the first cement

using 4, casing 5 and the second cement casing 6. The number of openings and their cross-sectional area is such that, at given specific injection rates and injection pressures, "critical flow conditions" exist within the outlet openings.

It was found, surprisingly, that given said flow conditions and conditions similar to them, neither combustion of the metal nor an explosion due to organic residues occurred. The critical flow conditions are defined such that at the appropriate temperature the gas is expelled at the velocity of sound. At this point it draws heat from the surrounding area to such an amount that rapid cooling occurs, thus preventing the ignition temperature of steel ($\sim 1100^\circ \text{C}$) and of organic residues ($> 150^\circ \text{C}$) being reached. The velocity of sound of the gas is reached with the pressure ratio prior to, and behind the outlet opening reaches 1.89. The pressure gradient of the borehole wall is generally determined by means of the injection pressure, the injection rate, the number of perforation openings plus their cross-sectional area and form, and the back pressure in the rock (reservoir pressure and friction loss in the rock). Only two of said characteristic magnitudes are independently variable, the remainder being fixed.

If one of the two pressures is given and the other is variable, and in addition the maximum injection rate is fixed, then the outlet cross-sectional area required to obtain critical flow conditions can be calculated.

$$F = \frac{q}{v [1 - (\gamma - 1)/2]^{1/\gamma - 1}}$$

$$v_{\max} = a_s = \{[2 \gamma / (\gamma + 1)] g R' T\}^{1/2}$$

F = outflow cross-sectional area (m^2)

q = gas flow rate in the pipe (m^3/s)

v = flow velocity in outlet opening (m/s)

T = temperature of gas in the pipe (K)

a_s = Laval velocity (velocity of sound in gas which cools during expansion (m/s))

γ = adiabatic exponent; for oxygen = 1.4

g = acceleration due to gravity; $9.81 \text{ (m/sec.}^2\text{)}$

R' = individual gas constants.

In these formulae flow conditions are assumed to be unrestricted. Experience has shown that this simplification can be used to the first approximation.

The following formula is used to calculate cooling at the outlet opening:

$$T/T_s = 1 - \frac{(\gamma - 1)(v^2 - a_s^2)}{2a_s^2}$$

T_2 = temperature of the expanding gas at Laval velocity (K)

Upon obtaining the sonic flow T_s , becomes = $0.829 T$. It has been shown that even given rapid compression of the gas in the pipe, no ignition of the metal parts or of the organic residue occurs since the perforated pipe forms in addition a "pressure rarefaction zone" and thereby cooling takes place, whereas the compression wave is clearly only formed on the most extreme peak of the pressure wave.

If residual oil is present in the borehole, or collects during the process, or if irremovable bituminous residues foul the wall of the pipe, there is an increased danger of explosion in the presence of oxygen. It has now been found that this danger can be eliminated if high grade grit or sand or Raschig rings is introduced

and packed into the cavities of the reservoir in which there is a danger of explosion. Grit packing 8 is therefore introduced into the extended liner 1, here having the form of a "sump", in order to render any residual oil present harmless in the presence of oxygen.

Obviously, in place of high-grade steel, cooper, brass, Inconel or Monel or other nickel alloys can be used as material for the liner. It is of particular advantage to maintain the oxygen concentration below 96% as this then rules out the possibility of autothermal (self-sustaining) combustion spreading. According to the subject method it is not essential that the oxygen be of the highest purity.

Occasionally admixture of inert gases, such as nitrogen, carbon dioxide or steam, is recommended in order to desensitize the oxygen. The oxygen should then be between about 80% and 96% pure.

The method for starting the operation of underground combustion (as described for example in German Auslegeschrift 2,263,960 and in German Patent No. 2,132,679) is performed in the following sequence of steps.

Phase I

The pressure in the petroleum reservoir is reduced as far as is possible and is necessary.

Since it is known that in an explosion the pressure can increase to 5 to 10 times the initial pressure, it is considered expedient for safety reasons to reduce the pressure in the reservoir, in a manner known per se, to slightly above the bubble-point of the reservoir liquid.

The igniters are injected into the upper region of the reservoir via the annulus, in the approximate sequence diesel oil, chemical igniters, water. The dimensions and composition of the chemical igniters can be determined for example in the manner described in German Auslegeschrift 2,263,960. The diesel oil slug should be of the same magnitude (volume) as the chemical igniters slug.

By means of nitrogen all the igniters are injected into the formation via the annulus. Simultaneously nitrogen is injected at a low rate (low excess pressure) into the reservoir via injection pipe 3, in order to prevent the igniters circulating back into the high-grade steel linear and injection pipe. When the chemical igniters are injected into the formation the ignition gas (20% - 80% volume oxygen concentration) is injected at the specific rate of approx. 10 - 50 m^3/m^2 rock surface per hour (gas volumes under normal conditions) until thermocouples set into the cement casing 4 of liner 1 indicate by an increase in temperature that ignition has taken place. The preferred specific injection rate of the gas is about 30 $\text{m}^3/\text{m}^2\text{h}$. The gas is subsequently injected at the same rate until the combustion front is at a distance of approx. 3 - 30 m from the injection borehole. The preferred distance from the combustion front to the injection borehole is about 5 to 15 m. There are then no more liquid hydrocarbons present in this zone, only solid oxidation residues.

Phase II

The oxygen concentration in the injection gas is increased in stages and the injection rate is increased to the maximum oxygen rate as set down in the process. The cross-sectional area of the perforations is calculated from this rate, in order to achieve critical flow conditions. The maximum oxygen rate depends on the process to be performed. It is pointed out here that even in

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subcritical flow conditions, an adequate cooling effect can be achieved in the borehole region.

Water is simultaneously injected via the annulus. The water/oxygen ratio should be within the range of from 1 - 15 m³ water per 1000 m³ oxygen (gas volumes under normal conditions). The oxygen concentration should be increased in stages, e.g. in three stages, from 30% - 50%, from 50% - 70% and from 70% - 90%. The reservoir pressure is increased until it lies within the range of from 80 bar to, for example, 150 bar.

Provision must be made that, in the event of the process being interrupted, nitrogen can be injected at any time into the injection pipe and into the annulus (Phase I) via a by-pass from the surface. This is to ensure that adequate control over the borehole is maintained (prevention of reflux, cooling down the borehole).

We claim:

1. A method for starting the operation of a process for the recovery of energy raw materials from a subterranean formation penetrated by a borehole comprising the steps of:

- a. introducing into the upper region of said formation igniters known per se,
- b. simultaneously introducing into the lower region of said formation an inert gas thereby preventing intrusion of said igniters into said lower region,
- c. subsequently introducing a gas with a predetermined oxygen concentration and injection rate into the lower region until ignition occurs and a combustion front is formed as indicated by a corresponding increases in temperature,
- d. continuing injection of said gas at said injection rate until the combustion front has been moved a predetermined distance into said formation,
- e. increasing said injection rate of said gas and/or oxygen concentration in said gas to a maximum rate and/or concentration respectively,
- f. injecting the said gas with the final oxygen concentration through at least one radially arranged outlet opening into the formation with a pressure ratio of flow-in pressure to discharge pressure at the outlet opening of 1.2 to 2.5, and
- g. simultaneously injecting water into the upper region of said formation.

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2. The method according to claim 1, characterized by injecting the oxygen at a pressure at which it flows into the reservoir at the velocity of sound.

3. The method according to claim 1, characterized in that, at the beginning of the injection processes, the reservoir pressure is lowered to slightly above the bubble-point of the reservoir liquid.

4. The method according to claim 1, characterized in that the injection processes are carried out via an injection borehole which, in the region of the reservoir, is divided into an upper and a lower injection region with no direct connection between these two regions.

5. The method according to claim 1, characterized by the oxygen concentration of the gas to be injected amounting to from 20 to 80 vol. %.

6. The method according to claim 1, characterized by increasing the injection rate and/or oxygen concentration in steps.

7. The method of claim 1, characterized by admixing with the process oxygen an inert gas.

8. The method of claim 7, wherein said inert gas is nitrogen, carbon dioxide, steam and mixtures thereof.

9. The method of claim 1, wherein said inert gas is present in amounts of from 4 to 20 vol. %.

10. The method according to claim 1, characterized by the specific injection rate of the gas amounting to from 10 to 50 m³/m²h.

11. The method of claim 10 wherein the specific injection rate is about 30 m³/m²h.

12. The method according to claim 1, characterized in that the distance from the combustion front to the injection borehole amounts to from 3 to 30 m, before the injection rate and/or oxygen concentration are stepwise increased to their final value.

13. The method of claim 12 wherein the distance from the combustion front to the injection borehole is 5 to 15 m.

14. The method according to claim 1, characterized by selecting a H₂O/O₂ ratio of 1 to 15 m³/1000 m³ O₂ (gas volumes at normal conditions).

15. The method according to claim 1, characterized in that all cavities in the reservoir region of the injection borehole in which a contact between oxygen and combustible materials is possible, are filled with porous filling material (e.g. sand, grit packing, Raschig rings).

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US007581587B2

(12) **United States Patent**
Pfefferle

(10) **Patent No.:** **US 7,581,587 B2**
(45) **Date of Patent:** **Sep. 1, 2009**

(54) **METHOD FOR IN-SITU COMBUSTION OF IN-PLACE OILS**

(75) **Inventor:** **William C. Pfefferle**, Madison, CT (US)

(73) **Assignee:** **Precision Combustion, Inc.**, North Haven, CT (US)

(*) **Notice:** Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 251 days.

(21) **Appl. No.:** **11/646,002**

(22) **Filed:** **Dec. 27, 2006**

(65) **Prior Publication Data**

US 2007/0256833 A1 Nov. 8, 2007

Related U.S. Application Data

(60) **Provisional application No.** 60/756,020, filed on Jan. 3, 2006.

(51) **Int. Cl.**
E21B 43/243 (2006.01)
E21B 43/30 (2006.01)

(52) **U.S. Cl.** 166/245; 166/256; 166/257;
166/272.1; 166/272.7; 166/306

(58) **Field of Classification Search** 166/272.7;
166/306

See application file for complete search history.

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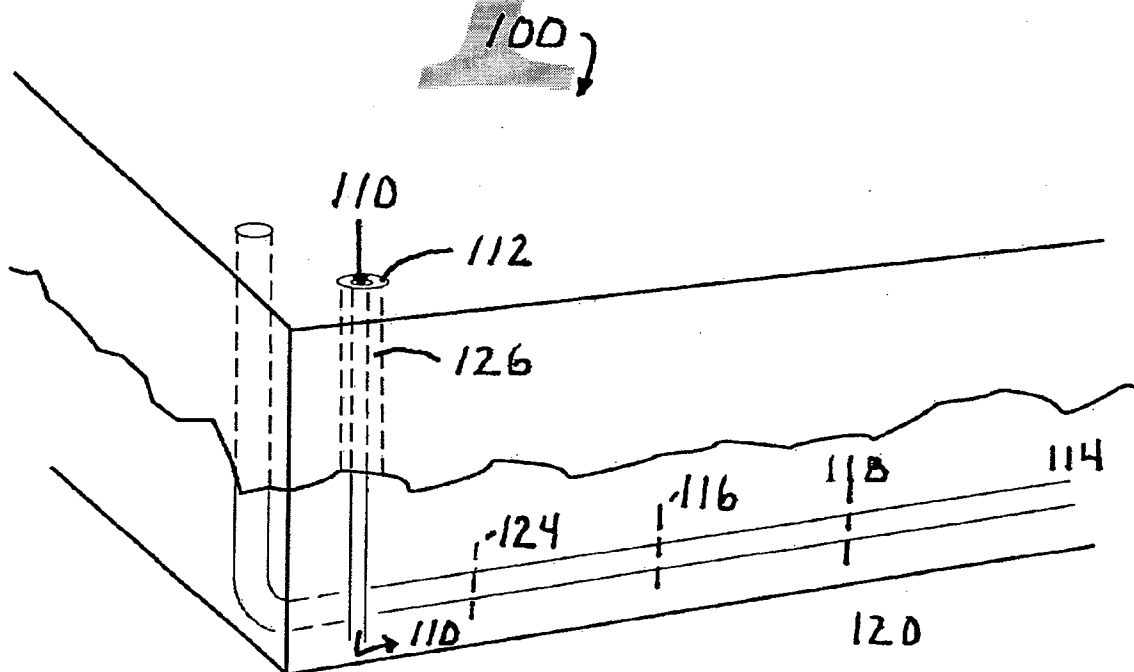
Primary Examiner—George Suchfield

(74) **Attorney, Agent, or Firm**—Robert L. Rispoli

(57) **ABSTRACT**

A novel method is provided for in situ combustion and recovery of oil from underground reservoirs including injecting air into the reservoir at a region near the reservoir floor, withdrawing combustion products from a region near the reservoir ceiling, and collecting oil from a horizontal production well near the reservoir floor.

9 Claims, 2 Drawing Sheets



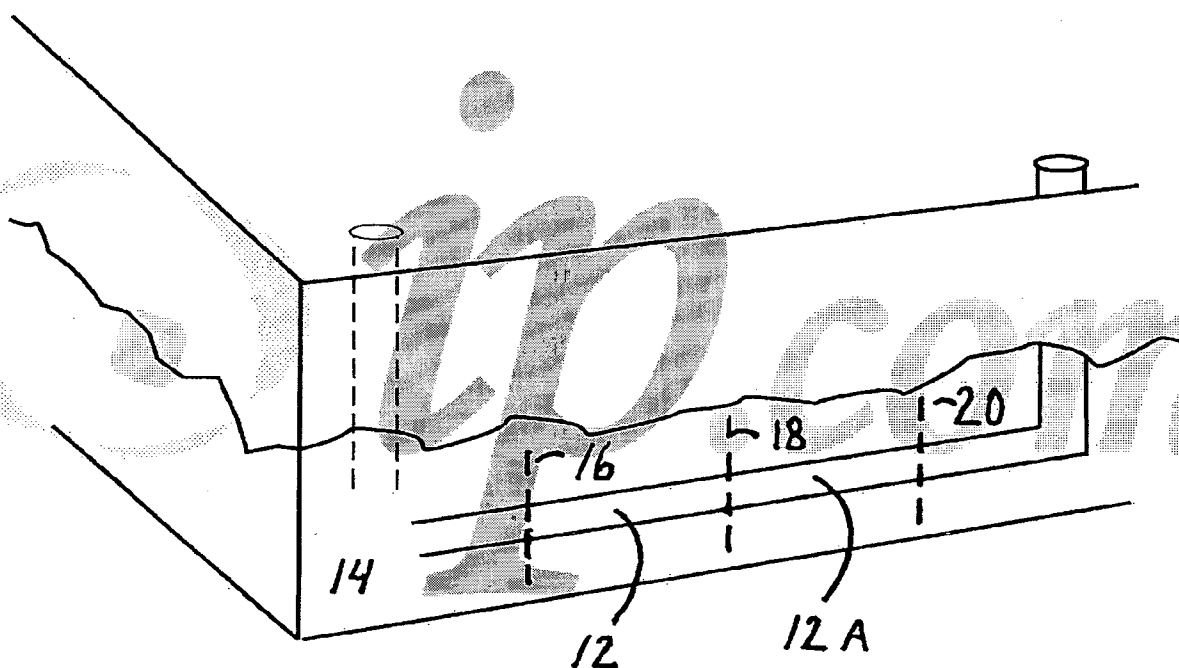


FIGURE 1 - PRIOR ART

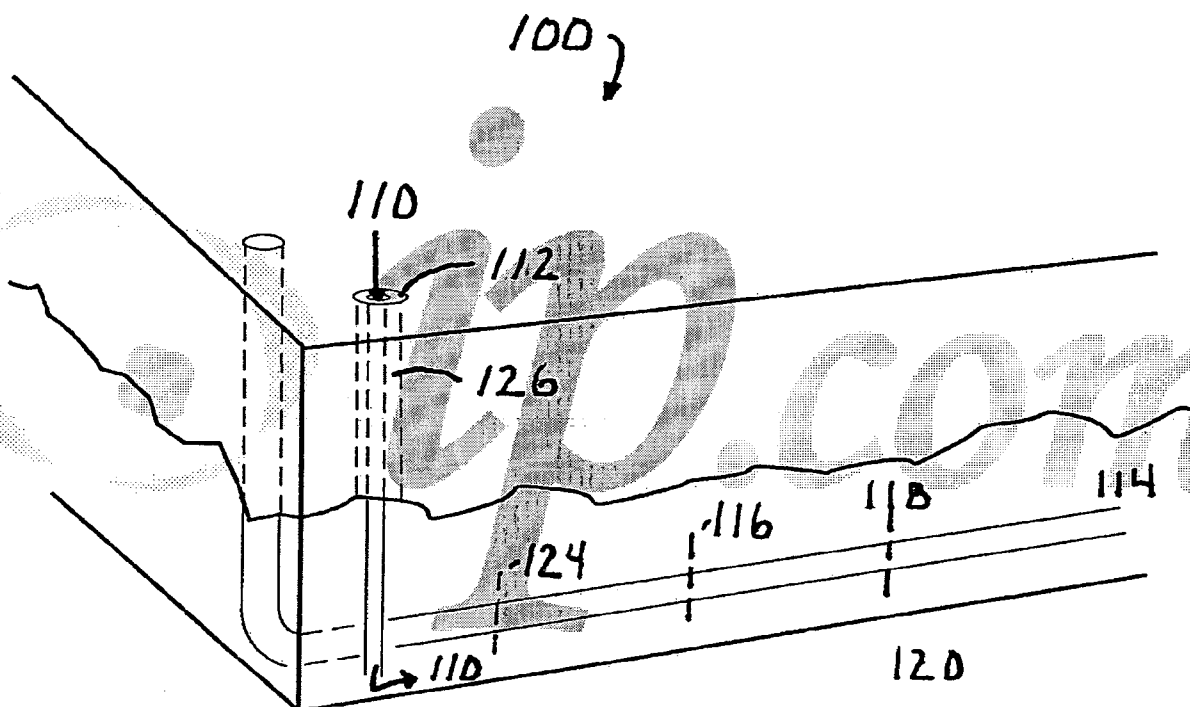


FIGURE 2

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METHOD FOR IN-SITU COMBUSTION OF IN-PLACE OILS

CROSS-REFERENCE

This application claims the benefit of U.S. Provisional Application No. 60/756,020 filed Jan. 3, 2006.

FIELD OF THE INVENTION

This invention relates to a method for contacting carbonaceous deposits in a sub-surface formation with a reactive fluid whereby such deposits may be mobilized thus allowing for recovery. More specifically, the invention relates to a method for efficient recovery and upgrading of heavy oils.

BACKGROUND OF THE INVENTION

In-situ combustion is an established method for enhanced oil recovery. In a typical application, air is injected into a vertical well resulting in combustion and increased oil mobility. Product oil is then recovered via either the injection well by a process known as huff-and-puff or via a second vertical well. The process is not widely used because it has been difficult to control. Thus attempts have been made to improve the process.

To reduce the problem of gravity segregation, for example, air is injected at a high point of the reservoir. U.S. Pat. No. 5,211,230 teaches injecting air at a high point of the reservoir via a vertical well along with a lower horizontal production well. U.S. Pat. No. 5,626,191 teaches placing the low horizontal well perpendicular to the vertical well to draw the combustion front along the horizontal well and away from the injection well. Although this is an improvement, combustion products are intended to be removed with the heated oil and thus injected fresh air also has ready access to the horizontal well between the toe and the combustion front. A further disadvantage is that the injection well and the horizontal well vertical leg must be located far apart. Accordingly, there is still a need for a process which is controllable and provides efficient use of injected air.

SUMMARY OF THE INVENTION

It is an object of the present invention to provide an improved method of contacting an injected fluid with a reaction front whereby oil may be recovered economically. More specifically, it is a further object of the present invention to enable more efficient in-situ combustion of in-place heavy oil whereby combustion products are more efficiently removed from the combustion zone and thermal cracking is promoted.

In the present invention, air is injected near the reservoir floor allowing the hot combustion products to over-ride the cooler fresh air. The cooler air is thus drawn to the combustion front aided by withdrawal of combustion products via a bleed well located at a point well above the reservoir floor. Use of a horizontal bleed well permits steering of combustion front travel. Advantageously, oil is recovered via a horizontal production well having its heel (the transition from horizontal to vertical rise to the surface) near the injection well. This means that the production well can be maintained liquid full throughout the air rich burned out zone blocking loss of injected air.

Combustion product gases may be withdrawn from a region near the top of the reservoir, preferably at an elevated pressure near the reservoir pressure. Passage of the withdrawn gases through a power turbine allows recovery of a

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portion of the energy required for compression of the injection air. Combustion of fuel to utilize oxidant in the withdrawn gases increases power output of the power turbine. Fresh air may be added as necessary to combust fuel values present in the combustion products.

An advantage of the present invention is that the oil recovery well(s) may be drilled from the same platform as the injection and bleed wells thereby reducing the environmental impact. Multiple production wells may be utilized depending upon the reservoir geometry. Typically, it will be advantageous to place the injection well at a low point in the reservoir. In addition, the required wells need not terminate directly under the production platform. If desired, injection and production wells may be drilled from separate platforms located some distance apart with the production well toe (i.e., horizontal terminus) located near the injection well.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a schematic representation of the state of the art system of U.S. Pat. No. 5,626,191.

FIG. 2 is a schematic representation of the present invention.

DESCRIPTION OF THE INVENTION

FIG. 1 depicts an advanced design in-situ combustion system of the prior art. Unlike the system of the present invention, excess combustion gases are withdrawn via the horizontal production well 12. Thus the horizontal section 12A of well 12 that lies within burned out zone 14 cannot withdraw combustion gases without preferentially bleeding off fresh air. As the combustion front progresses from location 16 through representative locations 18, 20, etc., loss of fresh combustion air worsens. To minimize fresh air loss, the toe section may be at a lower elevation than the heel so that the leg between the toe and the combustion front remains liquid full. This also allows oil to drain out of the toe into the reservoir. Even so, this is only a partial solution since hot gases will still tend to over-ride the cooler fresh air at the withdrawal point. The result is energy loss.

Referring to the drawings, FIG. 2 depicts a well pattern 100 for in-situ combustion according to the present invention. Air 110 is injected via well 112 at the bottom of reservoir 114 flowing to combustion front 116. Heated oil 118 drains to the reservoir floor on rock bed 120 and is withdrawn at a controlled rate such that horizontal well 122 is liquid full throughout burned out zone 124. Hot combustion gases rise at combustion front 116 and are withdrawn via concentric well 126 for energy recovery in a turbine (not shown). Well 126 need not be concentric with injection well 112 and may be located as the reservoir structure dictates or may be a horizontal well. Regardless, it is typically advantageous to drill all wells from a common platform.

While the present invention has been described in considerable detail, other configurations exhibiting the characteristics taught herein for a method for in-situ combustion of in-place oils are contemplated. Therefore, the spirit and scope of the invention should not be limited to the description of the preferred embodiments described herein.

The invention claimed is:

1. A method of in-situ combustion for recovery of oil from an underground oil reservoir comprising:
 - a) injecting air into the reservoir via an injection well in a region near the reservoir floor;

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- b) establishing a combustion front wherein hot combustion gases rise at the combustion front with combustion progressing from heel to toe;
 - c) withdrawing combustion products from a region near the reservoir ceiling whereby heated oil drains to the reservoir floor; and
 - d) collecting oil from a horizontal production well near the reservoir floor whereby the horizontal production well defines a heel proximate to the injection well.
2. The method of claim 1 wherein combustion products are withdrawn through a bleed well located above an air injection well flow exit.
3. The method of claim 2 wherein the bleed well includes a horizontal section perpendicular to a vertical injection well.

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4. The method of claim 1 wherein withdrawn combustion products are passed to an expansion turbine for energy recovery.
5. The method of claim 4 wherein fuel is combusted to heat the combustion products before expansion.
6. The method of claim 1 wherein the production well is drilled from the same platform as an air injection well.
7. The method of claim 1 wherein the toe of the production well is at a higher elevation than the heel.
8. The method of claim 1 wherein the production well is a horizontal well perpendicular to an injection well.
9. The method of claim 1 wherein combustion products are withdrawn through multiple bleed wells.

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- [54] METHOD FOR OPERATING A
PRODUCTION WELL IN AN OXYGEN
DRIVEN IN-SITU COMBUSTION OIL
RECOVERY PROCESS
- [75] Inventor: Billy G. Holmes, Lancaster, Tex.
- [73] Assignee: Mobil Oil Corporation, New York,
N.Y.
- [21] Appl. No.: 566,373
- [22] Filed: Dec. 28, 1983
- [51] Int. Cl.⁴ E21B 43/243; E21B 47/06
- [52] U.S. Cl. 166/251; 166/53;
166/64; 166/261
- [58] Field of Search 166/53, 57, 64, 251,
166/256, 261, 263, 302

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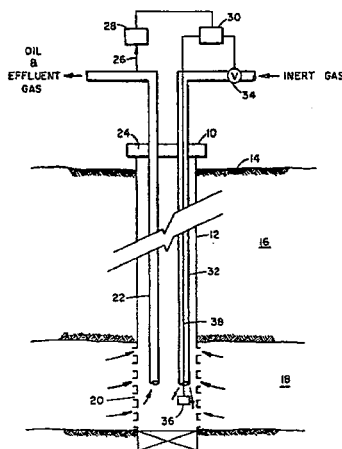
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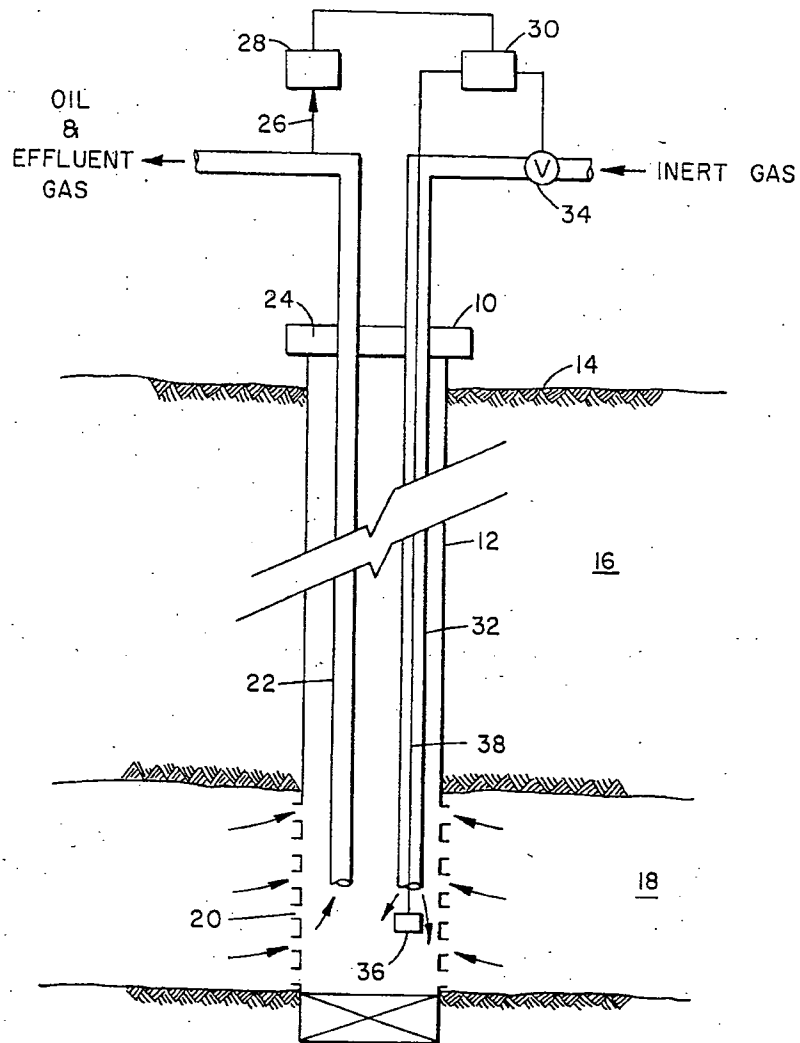
Primary Examiner—George A. Suchfield
Attorney, Agent, or Firm—Alexander J. McKillop;
Michael G. Gilman; Charles J. Speciale

[57] ABSTRACT

A method for operating a production well during an oxygen driven in-situ combustion oil recovery process comprising continuously injecting an inert gas such as nitrogen or carbon dioxide into the bottom of the production well at a predetermined low injection rate, preferably 0.1 to 2 MSCF/day, and continuously monitoring the oxygen concentration of the produced effluent gas and the bottomhole temperature of the production well. In the event that the oxygen content of the effluent gas increases to a value within the range of 5 to 20 volume percent or the bottomhole temperature of the production well increases to a value within the range of 200° to 300° F., the injection rate of the inert gas into the bottom of the production well is increased to a maximum rate until the oxygen concentration of the effluent gas and the bottomhole temperature are reduced to a safe level.

8 Claims, 1 Drawing Figure





METHOD FOR OPERATING A PRODUCTION WELL IN AN OXYGEN DRIVEN IN-SITU COMBUSTION OIL RECOVERY PROCESS

BACKGROUND OF THE INVENTION

This invention relates to an in-situ combustion recovery process within a subterranean, oil-containing formation using high concentrations of oxygen and more particularly to a method for operating a production well in such processes wherein a small amount of an inert gas is continuously injected into the bottom of the well which may be increased to a maximum rate if either the bottomhole temperature of the well or the oxygen content of the effluent gas from the well reach an unsafe level indicating a hazardous condition in the well.

Thermal recovery techniques, in which hydrocarbons are produced from carbonaceous strata such as oil sands, tar sands, oil shales, and the like by the application of heat thereto, are becoming increasingly prevalent in the oil industry. Perhaps the most widely used thermal recovery technique involves in-situ combustion or "fire flooding". In a typical fire flood, a combustion zone is established in a carbonaceous stratum and propagated within the stratum by the injection of air, oxygen-enriched air or pure oxygen through a suitable injection well. As the combustion supporting gas is injected, products of combustion and other heated fluids in the stratum are forced away from the point of injection toward production zones where they are recovered from the stratum and withdrawn to the surface through suitable production wells. U.S. Pat. Nos. 3,240,270-Marx, 4,031,956-Terry, and 4,042,026-Pusch et al are examples of the recovery of oil by in-situ combustion.

In such processes, the prevention of unintended ignition due to the hazardous nature of using pure oxygen is of primary concern. For example, as the combustion zone moves away from the injection well, a large volume of unreacted oxygen sometimes accumulates near the well. If this travels upwardly in the well, a catastrophic fire possibly destroying the well, can be ignited. U.S. Pat. No. 3,125,324-Marx discusses the ignition problem. In addition, U.S. Pat. No. 4,042,026 to Pusch et al disclosed above also discusses the hazardous nature of using pure oxygen in in-situ combustion operations that could lead to uncontrolled reactions or explosions.

U.S. Pat. No. 3,240,270 to Marx discloses an in-situ combustion process for the recovery of oil wherein an inert cooling fluid such as water, nitrogen, or carbon dioxide is injected into the production boreholes so as to maintain the temperature therein below combustion supporting temperature at the oxygen concentration therein and prevent borehole fires.

U.S. Pat. No. 3,135,324 to Marx discloses an in-situ combustion process for recovery of oil wherein a fine dispersion of water is injected with the combustion supporting gas in a sufficient amount to maintain the temperature of the stratum around the injection well below ignition temperature.

It is an object of the present invention to provide a method for safely operating a production well in an in-situ combustion oil recovery operation using high concentrations of oxygen.

SUMMARY OF THE INVENTION

The present invention relates to a method for recovering viscous oil from a subterranean, viscous oil-containing formation penetrated by at least one injection well and one production well and having fluid communication therebetween comprising establishing an in-situ combustion operation in the formation by injecting substantially pure oxygen into the formation via the injection well and recovering fluids including oil and an effluent gas from the formation via the production well, continuously injecting an inert gas such as nitrogen or carbon dioxide at a predetermined low injection rate, preferably 0.1 to 2 MSCF/day, into the lower portion of the the production well, continuously analyzing the effluent gas for oxygen concentration and monitoring the bottomhole temperature of the production well, and increasing the injection rate of said inert gas to a maximum rate if the oxygen concentration of said effluent gas increases to a predetermined concentration, preferably 5 to 20 volume percent, or if the bottomhole temperature of the production well increases to a predetermined temperature, preferably within the range of 200° to 300° F.

BRIEF DESCRIPTION OF THE DRAWING

The drawing shows a completion for a production well in accordance with the present invention.

DESCRIPTION OF THE PREFERRED EMBODIMENT

The present invention provides a method for operating a production well in an oxygen driven in-situ combustion oil recovery process to prevent production well fires or downhole explosions due to the presence of an unsafe amount of oxygen in the fluids produced from the production well or a high temperature in the bottom of the well. In a conventional forward in-situ combustion operation, an oxygen-containing gas such as air, oxygen-enriched air or essentially pure oxygen is introduced into the formation via an injection well and combustion of the in-place crude adjacent the injection well is initiated by one of many known means, such as the use of a downhole gas-fired heater or a downhole electric heater or chemical means. Thereafter, the injection of the oxygen-containing gas or pure oxygen is continued so as to maintain a combustion front which is formed, and to drive the front through the formation, heating and displacing crude petroleum ahead of it toward the production well from which fluids including oil and effluent gas are recovered. If oxygen by-passes the combustion and appears in the production well, uncontrolled borehole fires or explosions could occur, especially in the case where essentially pure oxygen is utilized to support the in-situ combustion operation.

Referring to the drawing, there is shown a production well 10 provided with a casing 12 extending from the surface 14 of the earth through the overburden 16 and into an oil-containing formation 18 from which oil is recovered by an oxygen driven in-situ combustion process. The production well 10 is in fluid communication with a substantial portion of the formation 18 by means of perforations 20. A production tubing 22 extends from the bottom portion of production well 10 adjacent the formation 18 through well head 24 for recovering fluids including oil and effluent gas from the formation. A portion of the effluent gas is withdrawn from tubing 22 through line 26 and passed into a gas

analysis means 28 to continuously analyze the oxygen content of the effluent gas recovered from the well. The oxygen analyzer sends signals to controller 30 in response to the oxygen content of the effluent gas.

An inert gas conduit 32 extends to a level in the bottom of the production well 10 adjacent the lower end of tubing 22. Conduit 32 passes through well head 24 and connects with a supply source of an inert gas such as nitrogen or carbon dioxide. A motor valve 34 is positioned in line 32 to control the fluid flow therein. Thermocouple 36, positioned in the bottom of production well 10 below conduit 32, sends signals via a suitable communication channel such as cable 38 to controller 30 in response to certain temperature conditions within the bottom of the well. Controller 30 functions to regulate motor valve 34 to control the amount of nitrogen or carbon dioxide injected into the bottom of the well via conduit 32 in response to the bottomhole production well temperature or the oxygen content of the effluent gas removed from tubing 22. Suspending the temperature sensing element 36 on cable 38 disposed within conduit 32 enables the sensing element to be easily replaced if it becomes inoperative.

During the in-situ combustion process, the oxygen content of the effluent gas in tubing 22 is constantly analyzed by analyzer 28 and the bottom hole temperature of the well is constantly monitored by thermocouple 36. In addition, during production, a stream of inert gas such as nitrogen or carbon dioxide is continuously injected at a predetermined low injection rate, preferably 0.1 to 2 MSCF/day, into the lower portion of the production well 10 via conduit 32. The rate of injection of inert gas through conduit 32 is controlled by motor valve 34. When the gas analysis means 28 indicates that the oxygen content of the effluent gas from production tubing 22 is within the range of 5 to 20 volume percent or when the bottomhole temperature sensed by thermocouple 36 is within the range of 200° to 300° F., controller 30 opens motor valve 34 and increases the flow rate of the inert gas to a maximum rate consistent with the pressure limitations of the formation. Production and injection of the inert gas is continued at the maximum rate until the oxygen content of the effluent gas is reduced to a safe level, preferably below 5 volume percent, and the bottomhole temperature is below 200° F. In addition, when the injection rate of the inert gas is increased to a maximum rate, the production well 10 may be shut-in and injection of oxygen into the formation via the injection well to support in-situ combustion may be terminated or reduced. Once the bottomhole temperature is below 200° F. and the oxygen content of the effluent gas from the production well is below 5 volume percent oxygen, injection of the inert gas is reduced to the predetermined low injection rate and production is continued.

Continuous injection of a small amount of inert gas into the bottom of the production well during production ensures instant availability of the gas in the event of a hazardous condition in the well.

While a particular embodiment of this invention has been shown and described, various modifications are within the true spirit and scope of the invention. The appended claims are, therefore, intended to cover all modifications.

What is claimed is:

1. A method for recovering viscous oil from a subterranean, viscous oil-containing formation penetrated by at least one injection well and one production well and having fluid communication therebetween comprising:

a. establishing an in-situ combustion operation in the formation by injecting substantially pure oxygen into the formation via the injection well and recovering fluids including oil and an effluent gas from the formation via the production well;

b. continuously injecting nitrogen at a predetermined low injection rate into the lower portion of the production well;

c. continuously analyzing the effluent gas for oxygen concentration and monitoring the bottomhole temperature of the production well;

d. increasing said injection rate of said nitrogen gas to a maximum rate in the event the oxygen concentration of said effluent gas increases to a predetermined concentration or the bottomhole temperature increases to a predetermined temperature indicating a hazardous condition; and

e. continuing injection of said nitrogen at a maximum rate until the oxygen concentration of the effluent gas and the bottomhole temperature are reduced to a safe level.

2. The method of claim 1 wherein the injection rate of the nitrogen is increased to a maximum rate when the oxygen content of the effluent gas is within the range of 5 to 20 volume percent or the bottomhole temperature of the production well is within the range of 200° to 300° F.

3. The method of claim 1 further including shutting-in the production well when the injection rate of the nitrogen is increased to a maximum rate.

4. The method of claim 1 wherein the injection rate of the nitrogen during step (b) is 0.1 to 2 MSCF/day.

5. A method for recovering viscous oil from a subterranean, viscous oil-containing formation penetrated by at least one injection well and one production well and having fluid communication therebetween comprising:

a. establishing an in-situ combustion operation in the formation by injecting substantially pure oxygen into the formation via the injection well and recovering fluids including oil and an effluent gas from the formation via the production well;

b. continuously injecting carbon dioxide at a predetermined low injection rate into the lower portion of the production well;

c. continuously analyzing the effluent gas for oxygen concentration and monitoring the bottomhole temperature of the production well;

d. increasing said injection rate of said carbon dioxide to a maximum rate in the event the oxygen concentration of said effluent gas increases to a predetermined concentration or the bottomhole temperature increases to a predetermined temperature indicating a hazardous condition; and

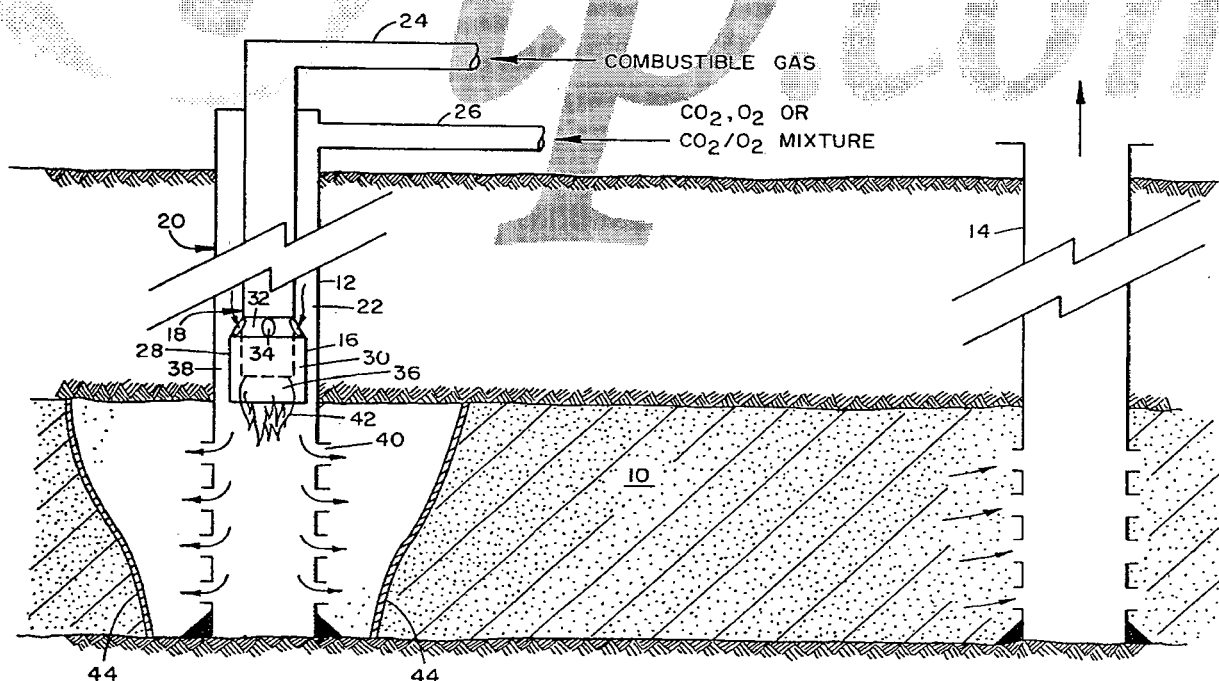
e. continuing injection of said carbon dioxide at a maximum rate until the oxygen concentration of the effluent gas and the bottomhole temperature are reduced to a safe level.

6. The method of claim 5 wherein the injection rate of the carbon dioxide is increased to a maximum rate when the oxygen content of the effluent gas is within the range of 5 to 20 volume percent or the bottomhole temperature of the production well is within the range of 200° to 300° F.

7. The method of claim 5 further including shutting-in the production well when the injection rate of the carbon dioxide is increased to a maximum rate.

8. The method of claim 5 wherein the injection rate of the carbon dioxide during step (b) is 0.1 to 2 MSCF/day.

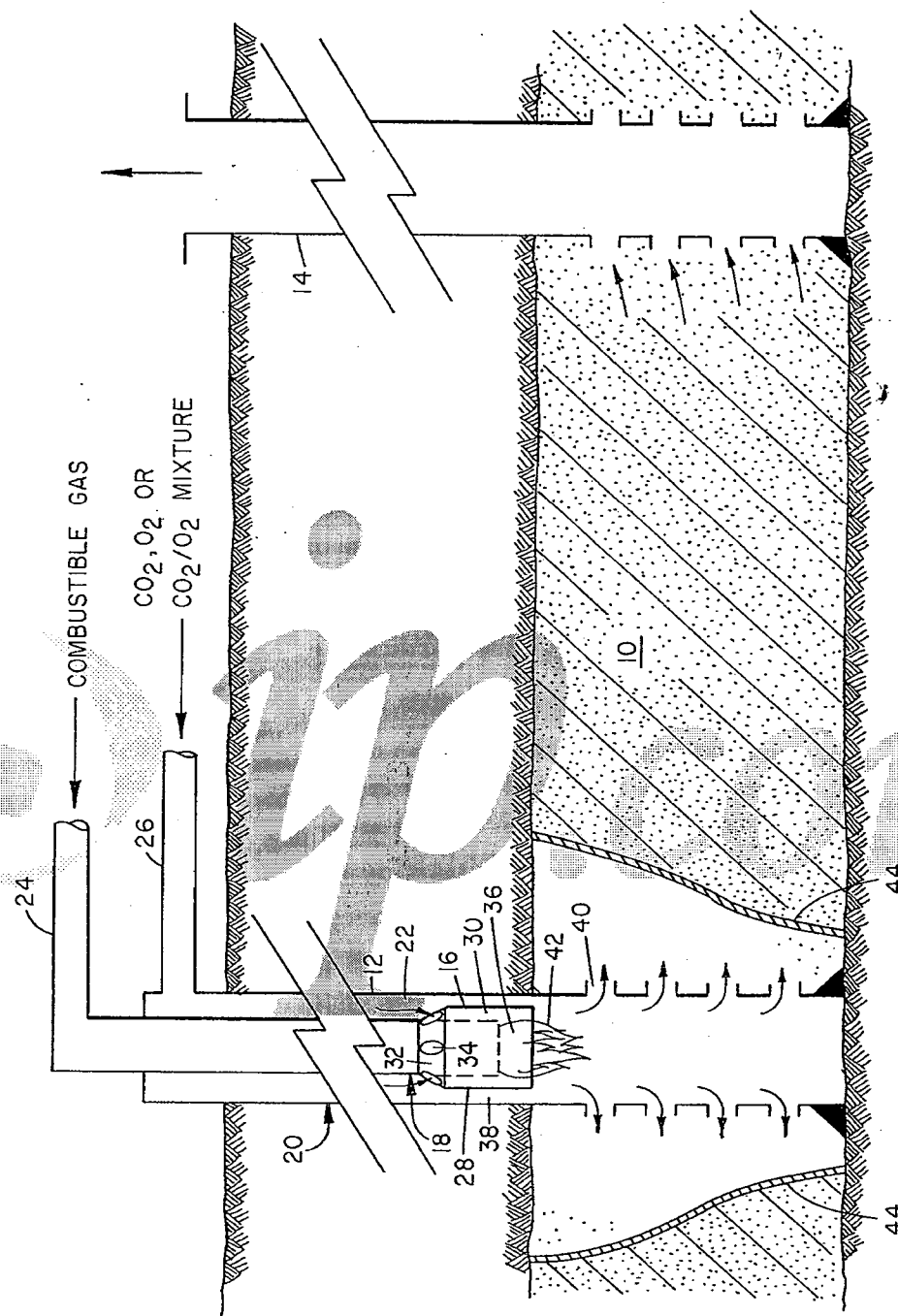
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U.S. Patent

Oct. 2, 1984

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METHOD FOR INITIATING AN OXYGEN DRIVEN IN-SITU COMBUSTION PROCESS

BACKGROUND OF THE INVENTION

This invention relates to a method for initiating an in-situ combustion process to recover energy raw materials such as petroleum hydrocarbons from a subterranean formation by the introduction of oxygen into the formation.

Since the invention of the in-situ combustion method for petroleum recovery by F. A. Howard in 1923, a number of methods have been developed, the object of which is the production of heat within the reservoir, especially of sufficient heat, by means of partial combustion of oil residues in a petroleum reservoir to enable recovery of the remaining oil. The most important mechanisms contributing to enhanced recovery are viscosity reduction by means of heat, distillation and cracking of the oil and of the higher boiling components, sweeping out of the oil with hot water and extraction of the oil by means of miscible products.

The use of high purity oxygen in place of air significantly improves the performance of the in-situ combustion process. One of the disadvantages of the use of oxygen is its hazardous nature that could lead to uncontrolled reactions or explosions. Because of the hazardous nature of pure oxygen in reacting with other materials much work has been done to reduce this danger. In addition to the question of reaction of oxygen with various materials, the dynamics of compressible fluids is also an important factor in determining what hazard exists when a material is reacted with oxygen.

It is known from experience in autogenous gas cutting that not only the nature of the material but also the composition of the gas used has an influence of the material's cutting quality. With an oxygen content of less than 95%, steel can still be ignited but combustion is not self-sustaining. These ratios apply to atmospheric pressure. In one series of tests, Hvizdos et al, (*Journal of Petroleum Technology*, June 1983, pp. 1061-1070), reported that samples of carbon steel with a geometry similar to the tubing used in injection wells were tested. The results of Hvizdos et al show that oxygen concentration and pressure have a dramatic effect on flame propagation. For instance, it was found that the tubing, once ignited, would not continue to burn if the oxygen concentration was below a critical level but that the flame would propagate if the oxygen concentration was over that level. The critical level of oxygen concentration is a function of pressure, illustrating that data at low pressure should not be used to plan projects which will operate at high pressure. For safety, a low limit of 45% oxygen should be used for a wide-range of pressures.

Great importance is accordingly attached to the structure of the spaces in which the oxygen is flowing. Should said spaces possess a large inner surface in relation to the volume, then the danger of an explosion when a fuel and oxygen are reacted is greatly reduced. Consequently the reaction of oxygen with oil contained in the pores of the reservoir rocks poses relatively few problems. However, given certain geometric proportions of the spaces through which the oxygen flows, local temperature peaks can occur and cause ignition of the material (steel, plastic, wood, etc.). It follows that the most dangerous point along the oxygen's flow path is the borehole. The operating conditions in a petroleum borehole are such that when high percentage oxygen is

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introduced there is a great danger of an explosion in the borehole. Neither is the borehole equipment made from deflagration-proof material (copper, Inconel) nor is the condition of the equipment, due to contact with corrosive, erosive and organic agents, such that the danger is lessened.

The injection of oxygen into a wellbore presents significant hazards and requires safety precautions. Previous work in this regard includes the injection of O₂ through a bottom water zone, as disclosed in U.S. Pat. No. 3,208,519 by T. V. Moore, and the initiation of combustion with air followed by oxygen as disclosed in U.S. Pat. No. 4,042,026 by G. Pusch et al. All these methods use air to establish gas flow. However, it has been found that injection of air increases the viscosity of the oil by 100 times when the oil is contacted by air for two days. This increase in viscosity is detrimental to the recovery process.

U.S. Pat. No. 1,410,042 to Shu discloses an in-situ combustion operation wherein a mixture of oxygen and carbon dioxide is injected into the formation to initiate combustion followed by injection of oxygen.

It is therefore the objective of this invention to eliminate these risks or at least reduce them to an acceptable level within the framework of conventional equipment used in boreholes for the recovery of energy raw materials such as petroleum hydrocarbons.

SUMMARY

The present invention relates to a method for initiating an in-situ combustion operation in a process for the recovery of oil from a subterranean, viscous oil-containing formation penetrated by an injection well and a spaced-apart production well comprising the steps of assembling a downhole burner in the injection well near the top of the formation, introducing a combustible gas such as methane or natural gas and a mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide into said downhole burner to produce a combustible mixture therein, igniting said combustible mixture to produce hot combustion gases containing heat energy that passes into the formation adjacent said injection well, continuing injection of said combustible gas and said mixture of oxygen and carbon dioxide until the temperature of the area of the formation surrounding the injection well is within the range of 500° to 800° F. Thereafter injection of the combustible gas is terminated and injection of the mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide into the formation via the injection well is continued to initiate in-situ combustion in the formation and form a combustion front therein. After formation of the combustion front or after the combustion front has advanced at least 30 feet into the formation, injection of the mixture of oxygen and carbon dioxide is terminated and thereafter essentially pure oxygen is injected into the formation via the injection well to support in-situ combustion.

BRIEF DESCRIPTION OF THE DRAWING

The accompanying drawing illustrates the method used in the invention for initiation of an in-situ combustion operation to recover oil from a subterranean formation.

DESCRIPTION OF THE PREFERRED EMBODIMENT

Referring to the drawing, there is shown a subterranean, viscous oil-containing formation 10 such as a heavy oil or tar sand deposit penetrated by an injection well 12 and at least one spaced-apart production well 14. Injection well 12 and production well 14 are perforated or other fluid flow communication is established between the wells and a substantial portion of the vertical thickness of the formation 10. While recovery of the type contemplated by the present invention may be carried out by employing only two wells, it is to be understood that the invention is not limited to any particular number of wells. The invention may be practiced using a variety of well patterns as is well known in the art of oil recovery, such as an inverted five spot pattern in which an injection well is surrounded with four production wells, or in a line drive arrangement in which a series of aligned injection wells and a series of aligned production wells are utilized. Any number of wells which may be arranged according to any pattern may be applied in using the present method as illustrated in U.S. Pat. No. 3,927,716 to Burdyn et al, the disclosure of which is hereby incorporated by reference. Either naturally occurring or artificially induced fluid communication should exist between the injection well 12 and the production well 14. Fluid communication can be induced by injection of carbon dioxide, a solvent or steam. Fracturing may also be employed to improve the transmissibility of the formation using procedures well known in the art.

A gas fired burner, denoted generally by the reference numeral 16 is contained within injection well 12 and positioned just above the oil-containing formation 10. Referring to the drawing, the burner 16 which takes the general shape of an inverted Bunsen burner comprises tubing 18 disposed and centered within well casing 20 to form annular chamber 22 between said tubing and said casing, said tubing 18 being open at its downstream end. The upstream or upper end of tubing 18 located on the surface is in communication with conduit 24 connected to a source of a combustible gas such as natural gas or methane. Conduit 26 located on the surface is connected to a source of oxygen and carbon dioxide and is in communication with annular space 22. Said burner 16 comprises a flame tube 28 disposed concentrically around tubing 18 to form an annular chamber 30 around said tubing and between said tubing and said flame tube. Said flame tube 28 is open at its downstream end which extends beyond the downstream end of tubing 18 to a position near the upper portion of the formation 10. An annular connecting section 32 tapers in increasing cross-sectional area from a point above the lower end of tubing 18 to the upstream end of flame tube 28. A plurality of openings 34 are provided in the wall of said connecting section 32 for admitting a portion of the combustion-supporting gas from annular chamber 22 into annular chamber 30 and is then mixed with fuel emerging from the end of tubing 18 to form a combustible mixture in combustion zone 36. Flame tube 28 centered in well casing 20 forms an annular chamber 38 around said flame tube, and between said flame tube and said well casing. Both the well casing 20, tubing 18 and flame tube 28 of the injection well 12 are made of carbon steel commonly used in oil fields.

If it is determined that the formation 10 does not possess naturally occurring permeability to fluids, car-

bon dioxide is injected into the formation via conduit 26, annulus 22, and through perforations 40 of injection well 12 for a period of time sufficient to establish fluid communication between the injection well 12 and the production well 14.

Thereafter, a combustible gas such as methane or natural gas is supplied to combustion zone 36 via conduit 24 and tubing 18. A mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide is passed via conduit 26 down through annular chamber 22. A portion of the mixture of oxygen and carbon dioxide in annulus 22 passes into combustion zone 36 via openings 34 and annulus 30 to form a combustible mixture with the gas emerging from the end of tubing 18. A small amount of a pyrophoric material is lowered down tubing 18 to ignite the combustible mixture in combustion zone 36 and produce hot combustion gases 42 containing heat energy. A thermocouple (not shown) is positioned in burner 16 for detecting ignition of the combustible mixture. That portion of the oxygen and carbon dioxide that does not pass through openings 34 from annulus 22 passes through annulus 38 and mixes with combustion gases emerging from the end of flame tube 28 thereby becoming hot. The hot combustion gases and heated excess mixture of oxygen and carbon dioxide from annulus 38 pass into the formation 10 via perforations 40 to heat the formation, and combustion in burner 16 is continued until the temperature of the area of the formation surrounding the injection well 12 is within the range of 500° to 800° F. Thereafter injection of the combustion gas is terminated and injection of the mixture of oxygen and carbon dioxide containing 55 to 80 volume percentage carbon dioxide is continued to spontaneously initiate in-situ combustion in the formation 10 and form a combustion front 44. The use of a gaseous mixture containing not more than 80 volume percent carbon dioxide does not interfere with initiation of in-situ combustion while using not less than 55 volume percent carbon dioxide (or no more than 45 volume percent oxygen) prevents flame propagation in the case of a downhole tubing fire.

Once the combustion front 44 is formed in the formation 10, or after sufficient oxygen and carbon dioxide have been injected to advance the combustion front away from the injection well 12 a predetermined distance, preferably at least 30 feet, injection of the mixture of O₂/CO₂ is terminated and thereafter essentially pure oxygen is injected into the formation via the injection well to support combustion, and fluids including oil are recovered from the formation via the production well 14. In another embodiment, after in-situ combustion has been initiated or after the combustion front has advanced away from the injection well a distance of at least 30 feet, the oxygen concentration of the injected O₂/CO₂ mixture is gradually increased at a controlled rate until the gas being injected is essentially pure oxygen. Advancing the combustion front 44 away from the injection well 12 before injecting essentially pure oxygen into the formation 10 ensures that there is no hydrocarbon residue near the injection well to come into contact with a gas containing more than 45 volume percent oxygen that could cause a downhole fire or explosion.

The use of a mixture of oxygen and carbon dioxide as the combustion-supporting gas to initiate in-situ combustion does not promote degradation in oil viscosity due to oxidation as is the case with mixture of oxygen and nitrogen as disclosed in prior arts. In the present

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process, any increase in oil viscosity due to oxidation is more than offset by a reduction in viscosity due to carbon dioxide dissolution. For example, an Athabasca bitumen with a viscosity of 50,000 cp at 104° F. will have a reduction in viscosity by 1000 times, when saturated with carbon dioxide at 600 psia (see Jacobs, F.A., et al, *J. Can. Pet. Tech.*, Oct.-Dec., 1980, pp. 46-50). In the latter example, it is disclosed that it requires only 200 scf of carbon dioxide to saturate a barrel of oil at 600 psia. Assuming the oil saturation is 100 bbls/ac-ft, it requires only 0.2×10^6 scf/ac-ft of carbon dioxide to saturate the oil. After in-situ combustion has been initiated, there is a sufficient amount of carbon dioxide generated in-situ to saturate the oil in the formation so there is no need to continuously inject carbon dioxide during the combustion process. It is noted that the dissolution of the carbon dioxide in the oil reduces the free gas in the reservoir and increases effective oil permeability. In addition, carbon dioxide has a nice fire-extinguishing characteristic which can be conveniently applied in the case of an accidental wellbore ignition.

The oxygen and carbon dioxide may both be stored in liquid form near the injection well or wells. Both materials may be more conveniently pumped in liquid form from separate storage tanks into a vaporizer and then injected into the injection well. The composition of the oxygen/carbon dioxide mixture supplied to the injection well is controlled by sensing and controlling the flow rates of the individual oxygen and carbon dioxide streams by means of a flow controller.

What is claimed is:

1. A method for initiating an in-situ combustion operation in a process for the recovery of oil from a subterranean, viscous oil-containing formation penetrated by an injection well and a spaced-apart production well comprising the steps of:

- (a) assembling a downhole burner having a combustion section in the injection well located near the formation;
- (b) introducing a combustible gas and a mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide into the combustion section of said downhole burner to produce a combustible mixture therein;

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(c) igniting said combustible mixture to produce hot combustion gases containing heat energy that passes into the formation adjacent said injection well;

(d) continuing injection of said combustible gas and mixture of oxygen and carbon dioxide until the temperature of the area of the formation surrounding the injection well is within the range of 500° to 800° F.;

(e) thereafter terminating the injection of the combustible gas and continuing to inject the mixture of oxygen and carbon dioxide containing 55 to 80 volume percent carbon dioxide into the formation via the injection well to initiate in-situ combustion in the formation and form a combustion front; and

(f) terminating injection of the mixture of oxygen and carbon dioxide and thereafter injecting essentially pure oxygen into the formation via the injection to support in-situ combustion in the formation.

2. The method of claim 1 wherein said combustible gas is natural gas.

3. The method of claim 1 wherein said combustible gas is methane.

4. The method of claim 1 further including the step of continuing injection of said mixture of oxygen and carbon dioxide during step (e) until the combustion front has moved a predetermined distance into said formation.

5. The method of claim 4 wherein the combustion front has moved a distance of at least 30 feet into the formation from the injection well.

6. The method of claim 1 further including increasing the oxygen concentration of the injected mixture of oxygen and carbon dioxide following step (e) until the injected gas comprises essentially pure oxygen.

7. The method of claim 1 wherein said downhole burner is formed from an elongated vertical combustion chamber means open at both ends, having both combustible gas supply and oxygen/carbon dioxide mixture supply conduits connected thereto for mixing the combustible gas and mixture of oxygen and carbon dioxide in the combustion chamber.

8. The method of claim 1 wherein the tubing and casing of the injection well comprises carbon steel.

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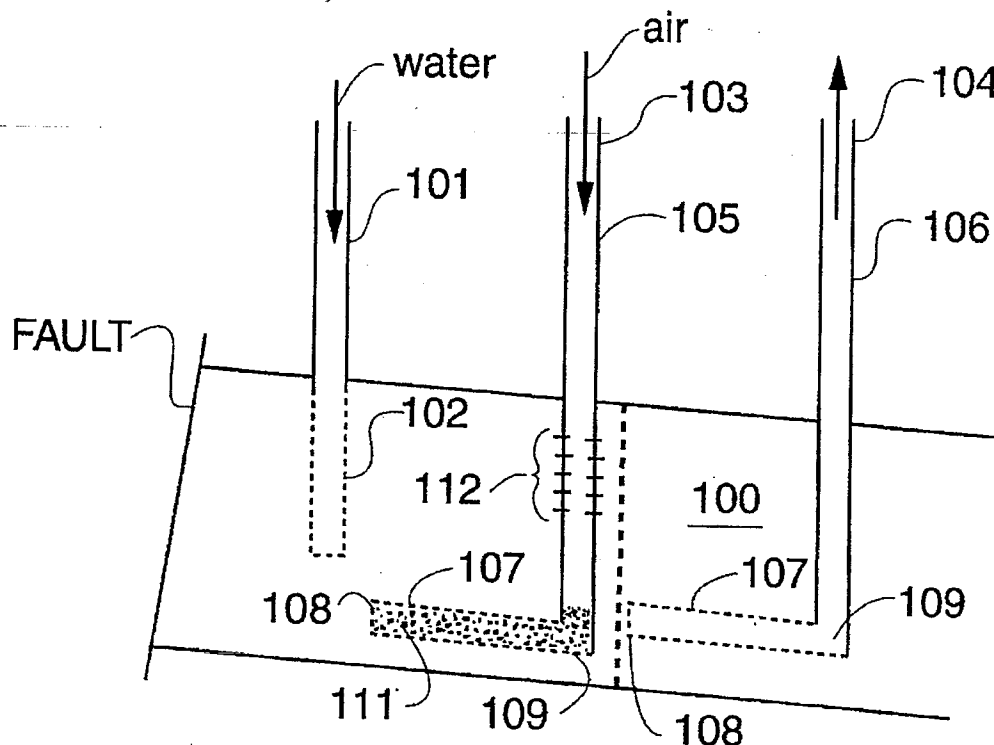
US005626191A

United States Patent [19]

Greaves et al.

[11] Patent Number: **5,626,191**[45] Date of Patent: **May 6, 1997**[54] **OILFIELD IN-SITU COMBUSTION PROCESS**[75] Inventors: **Malcolm Greaves**, Avon, United Kingdom; **Alexandru T. Turta**, Calgary, Canada[73] Assignee: **Petroleum Recovery Institute**, Calgary, Canada[21] Appl. No.: **494,300**[22] Filed: **Jun. 23, 1995**[51] Int. Cl.⁶ **E21B 43/24; E21B 43/243; E21B 43/30**[52] U.S. Cl. **166/245; 166/50; 166/261; 166/263**[58] Field of Search **166/50, 245, 256, 166/261, 263, 272**[56] **References Cited****U.S. PATENT DOCUMENTS**3,017,168 1/1962 Carr 166/256 X
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5,456,315 10/1995 Kisman et al. 166/50 X*Primary Examiner*—George A. Suchfield*Attorney, Agent, or Firm*—Sheridan Ross P.C.[57] **ABSTRACT**

A well arrangement is used wherein the production wells are generally horizontal, positioned low in the reservoir and arranged generally perpendicularly to a laterally extending combustion front. The combustion front is propagated by a row of vertical air injection wells completed high in the reservoir. The open production wells function to cause the combustion front to advance along their lengths. The process is characterized by a generally upright combustion front having good vertical and lateral sweep.

7 Claims, 14 Drawing Sheets

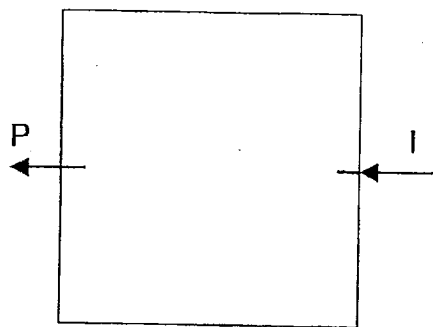


FIG. 1A.

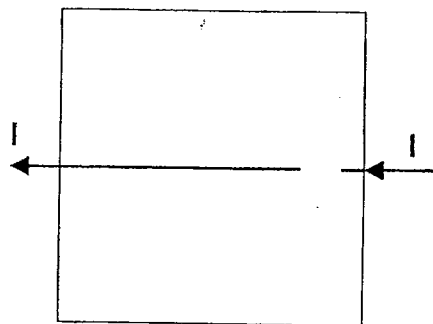


FIG. 2A.

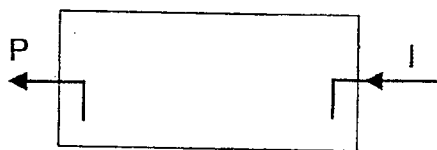


FIG. 1B.

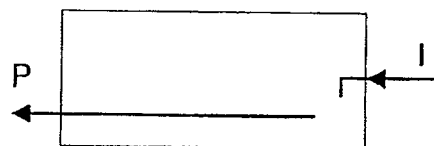


FIG. 2B.

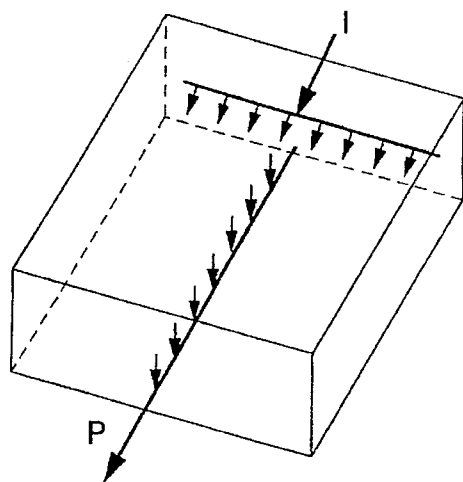


FIG. 3.

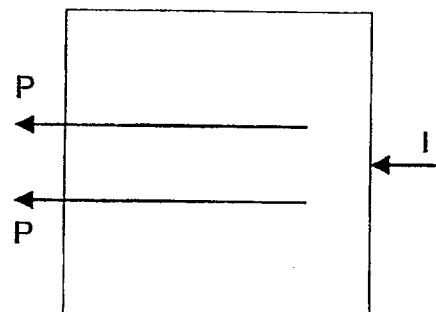


FIG. 4A.

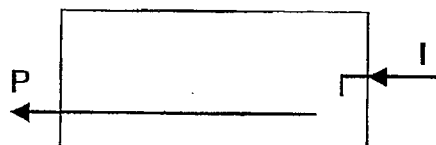


FIG. 4B.

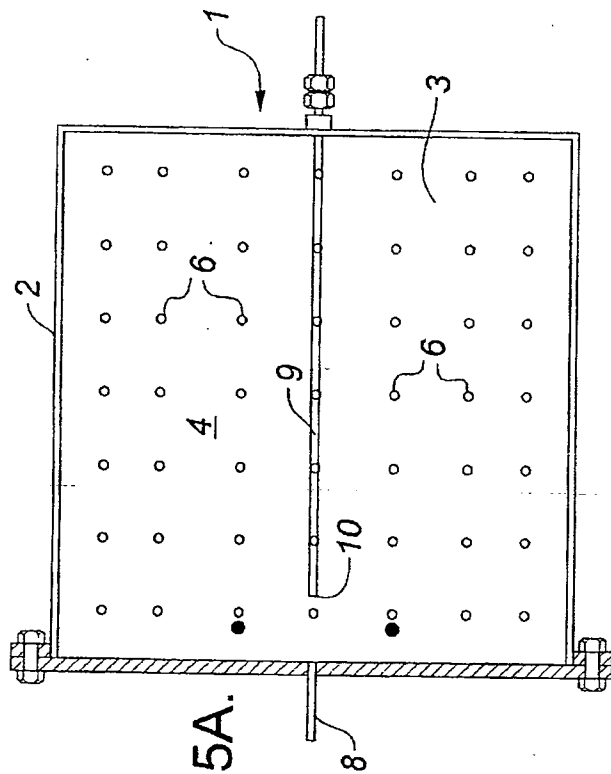


FIG. 5A.

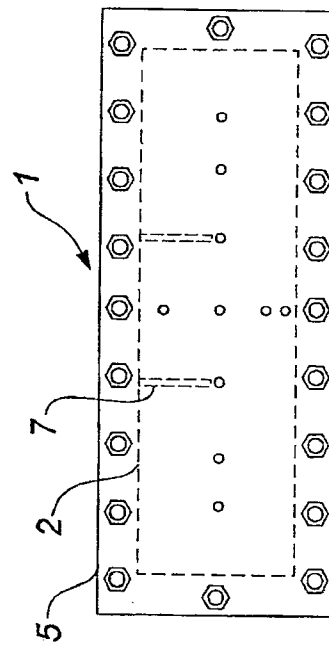


FIG. 5C.

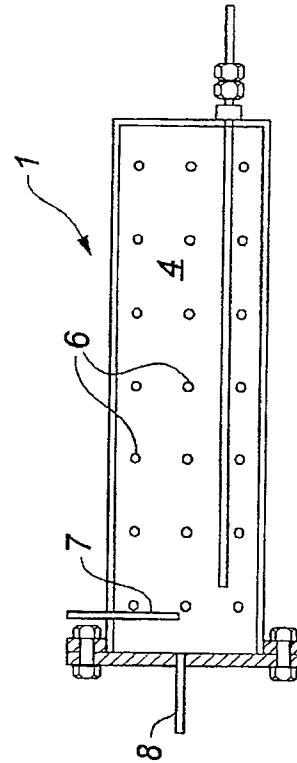


FIG. 5B.

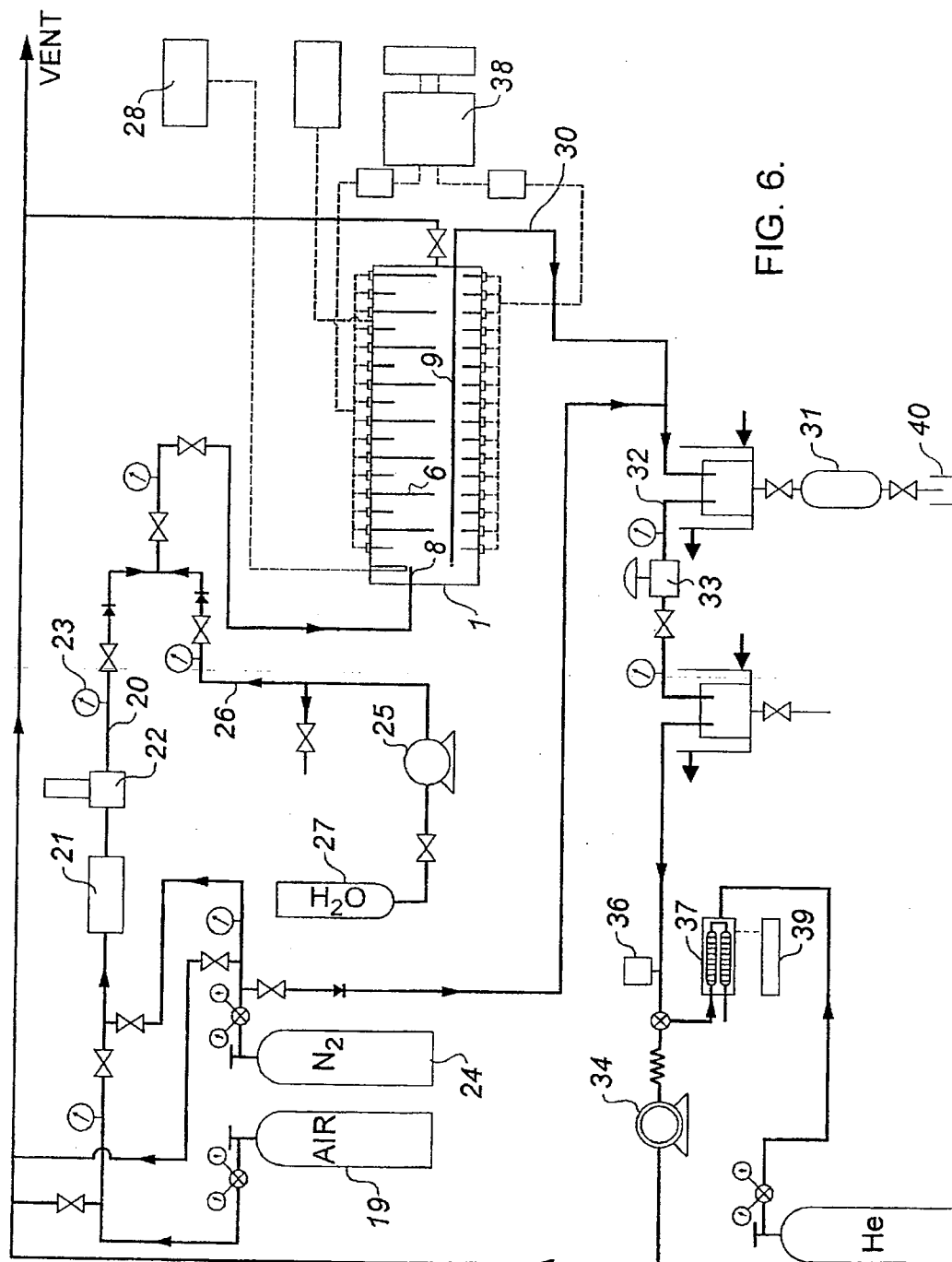
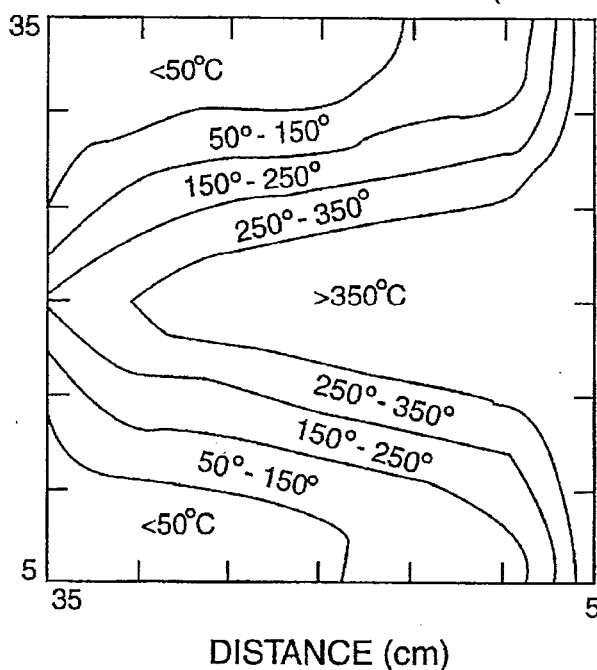


FIG. 6.

Fig. 7A (PRIOR ART)

VOLUME SWEEPED BY THE COMBUSTION FRONT
ALONG THE HORIZONTAL MIDPLANE (Time = 930 min.)

**Fig. 7B** (PRIOR ART)

VOLUME SWEEPED BY THE COMBUSTION FRONT
ALONG THE VERTICAL MIDPLANE (Time = 930 min.)

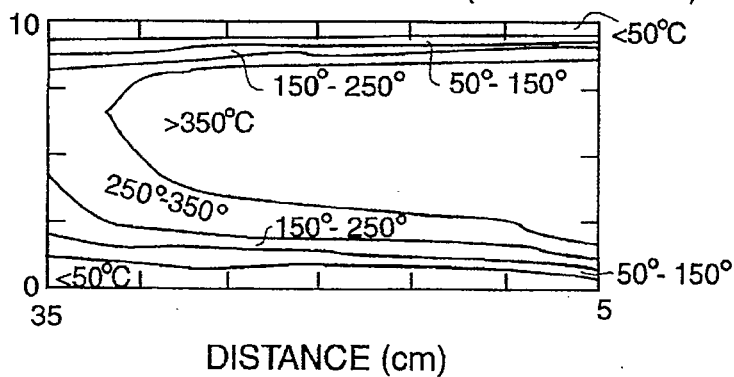
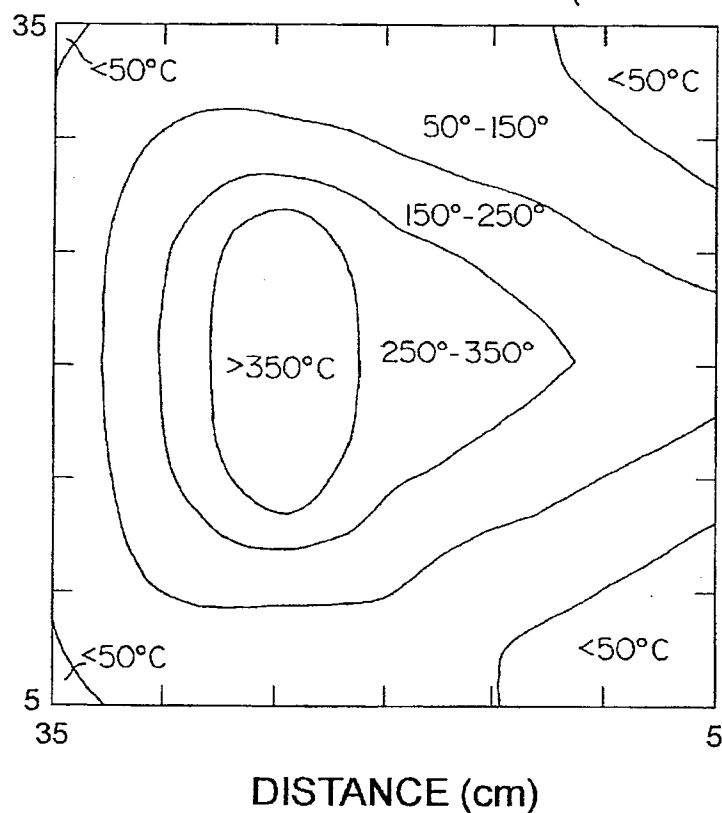


FIG. 8A.

VOLUME SWEEPED BY THE COMBUSTION FRONT
ALONG THE HORIZONTAL MIDPLANE (Time = 999 min.)

**FIG. 8B.**

VOLUME SWEEPED BY THE COMBUSTION FRONT
ALONG THE VERTICAL MIDPLANE (Time = 999 min.)

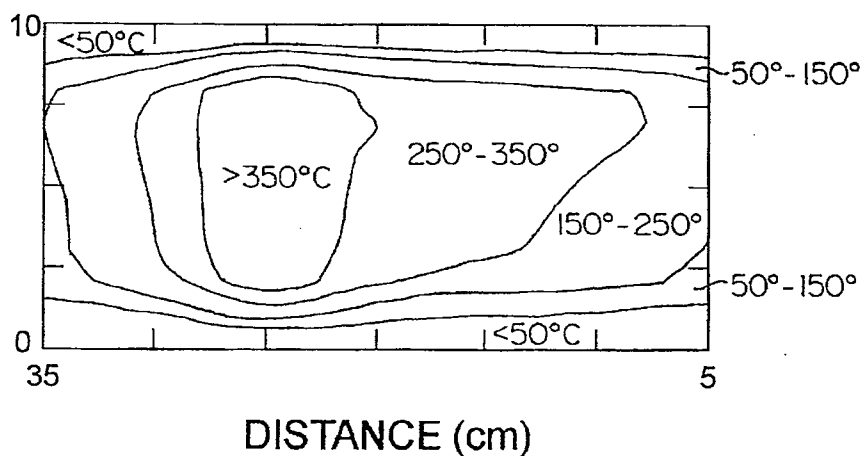


FIG. 9A.

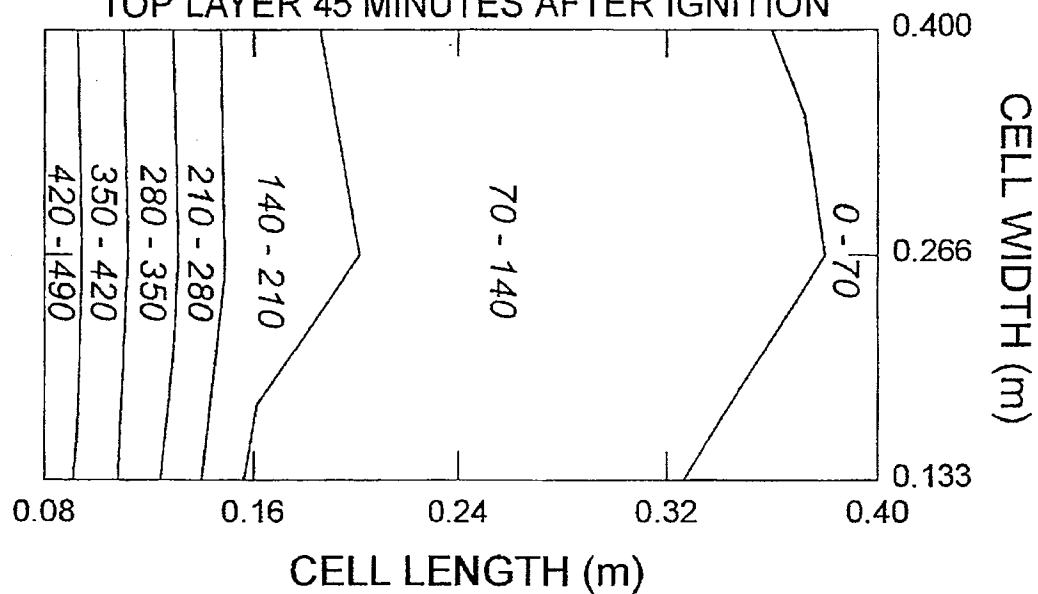
HORIZONTAL TEMPERATURE PROFILES AT
TOP LAYER 45 MINUTES AFTER IGNITION

FIG. 9B.

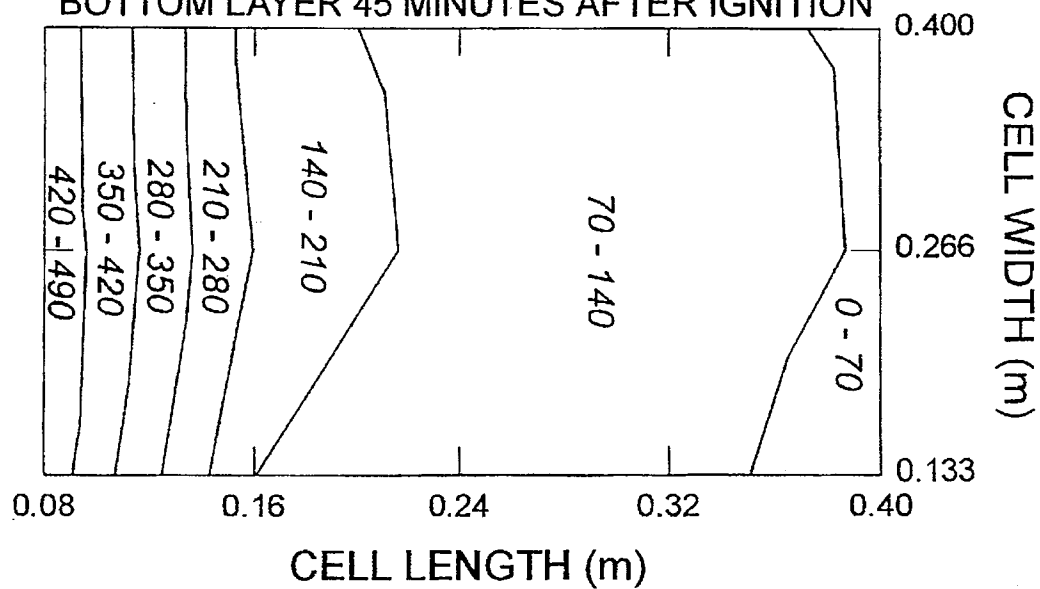
HORIZONTAL TEMPERATURE PROFILES AT
BOTTOM LAYER 45 MINUTES AFTER IGNITION

FIG. 9C.

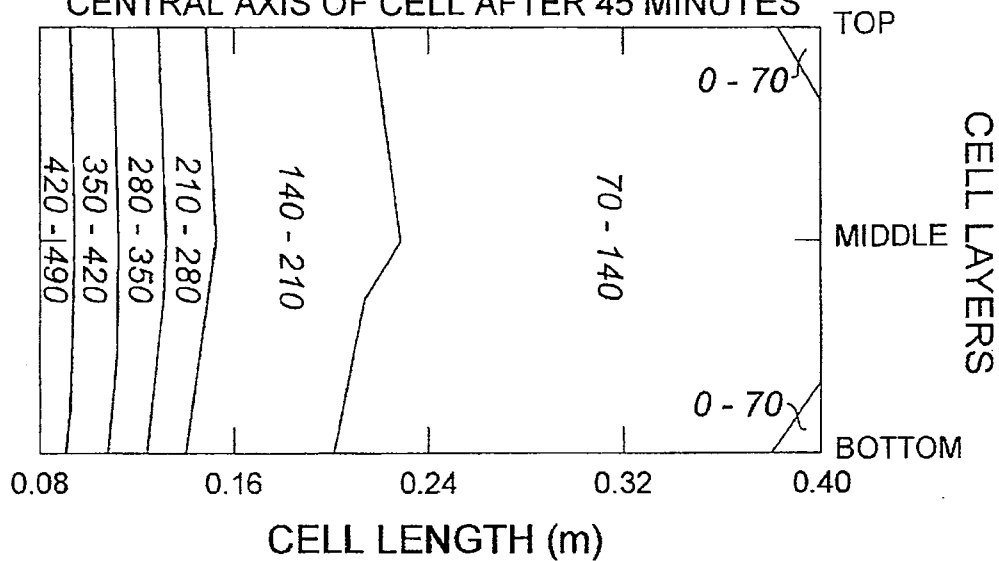
VERTICAL TEMPERATURE PROFILES ALONG
CENTRAL AXIS OF CELL AFTER 45 MINUTES

FIG. 9D.

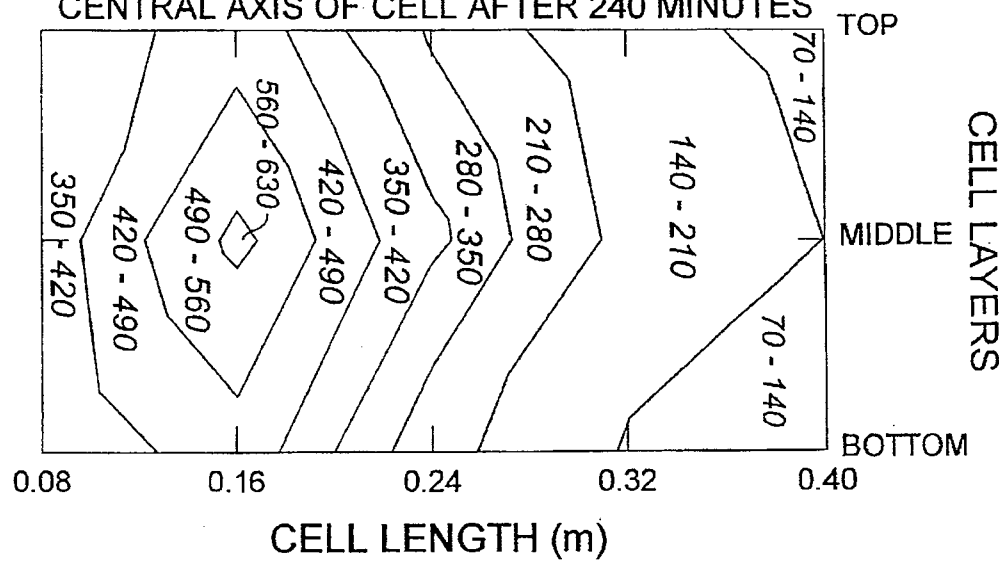
VERTICAL TEMPERATURE PROFILES ALONG
CENTRAL AXIS OF CELL AFTER 240 MINUTES

FIG. 9E.

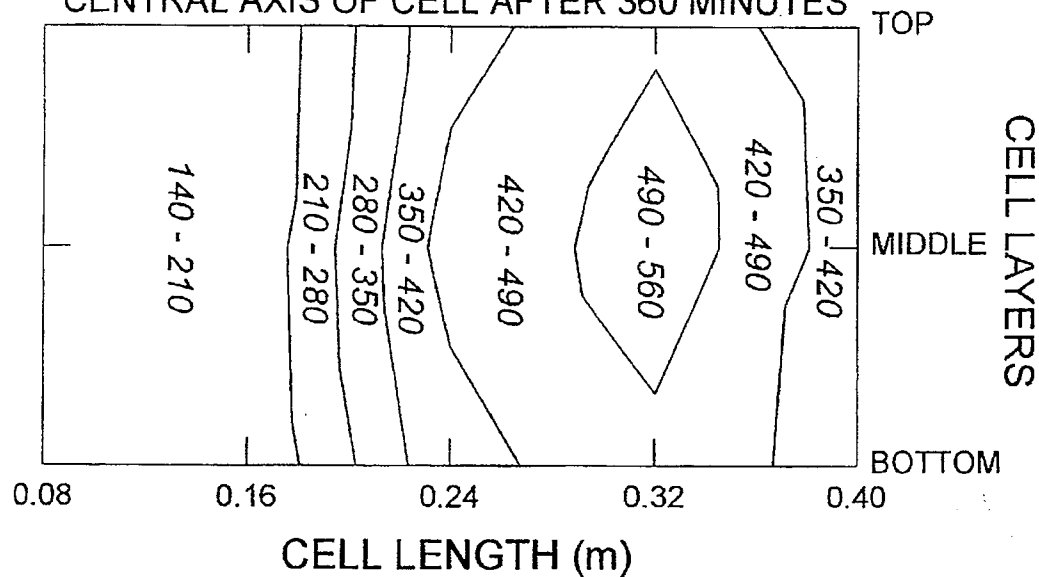
VERTICAL TEMPERATURE PROFILES ALONG
CENTRAL AXIS OF CELL AFTER 360 MINUTES

FIG. 9F.

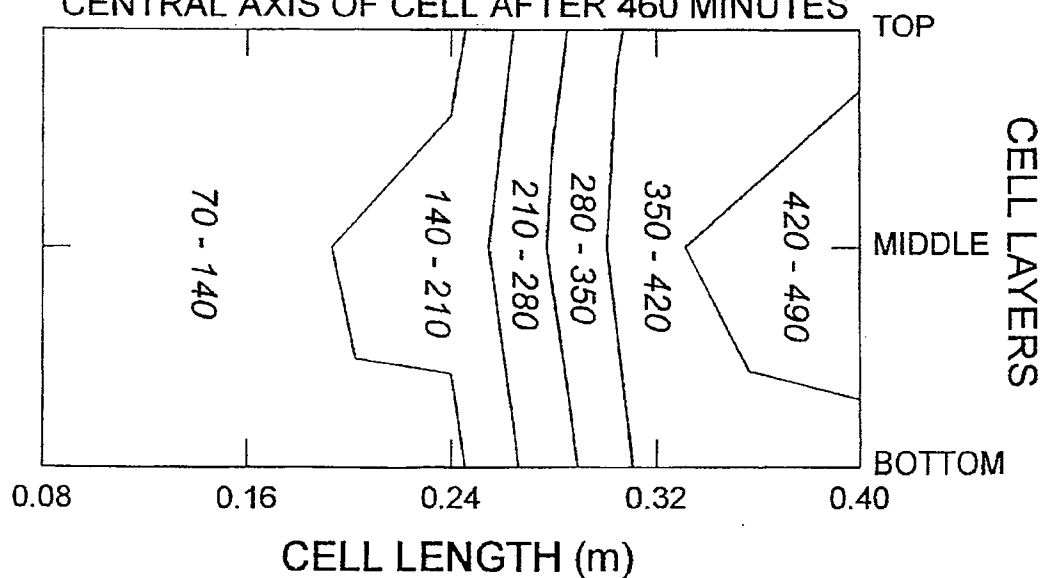
VERTICAL TEMPERATURE PROFILES ALONG
CENTRAL AXIS OF CELL AFTER 460 MINUTES

FIG. 10.

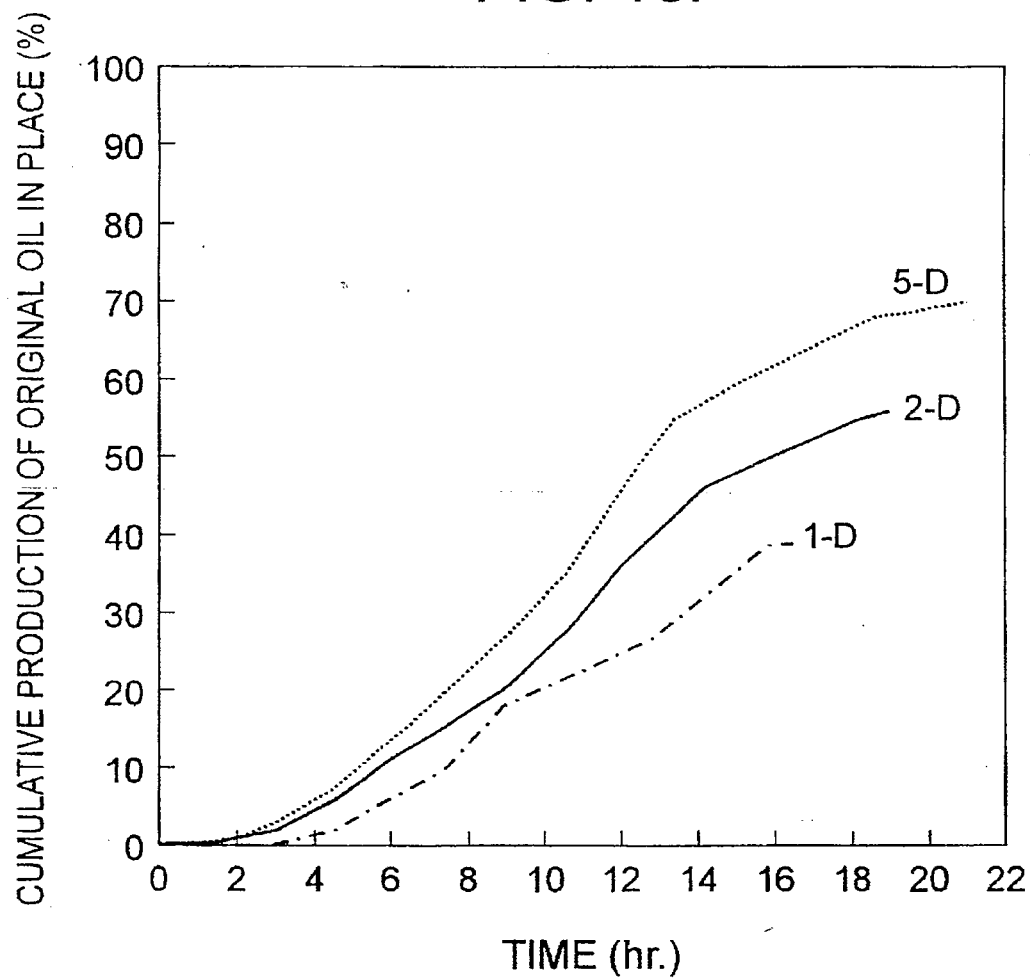


FIG. 11.

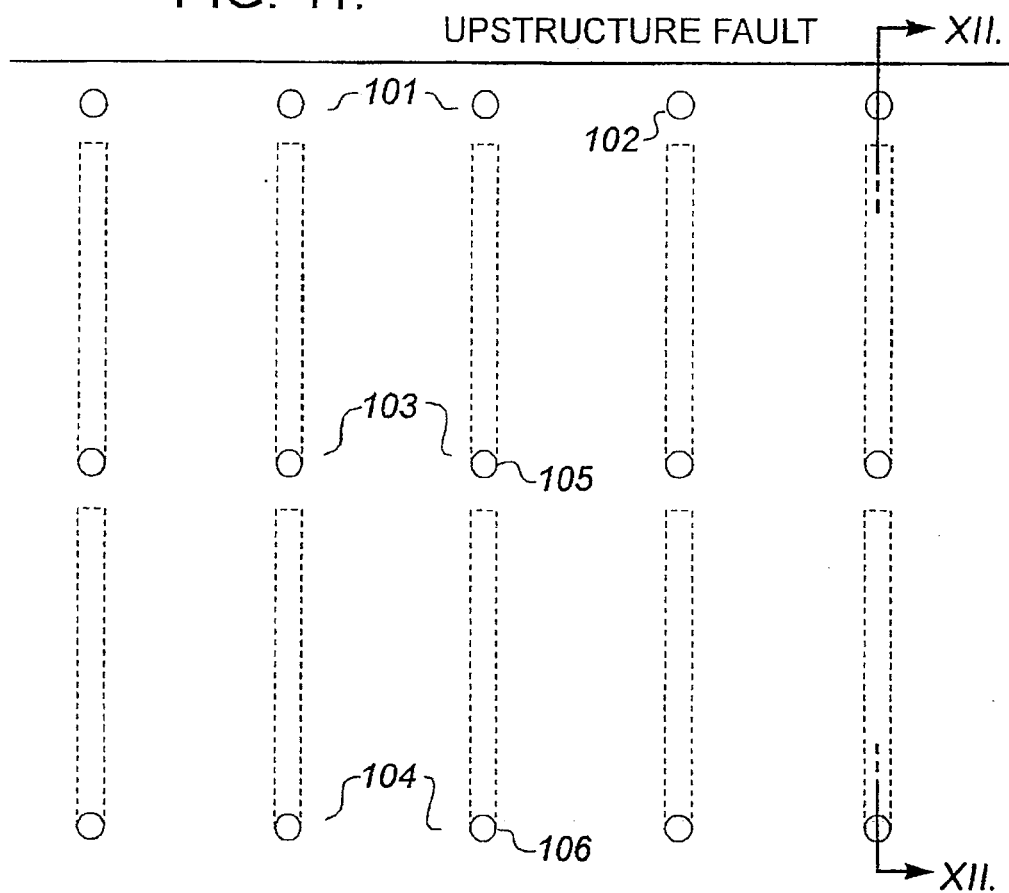


FIG. 12.

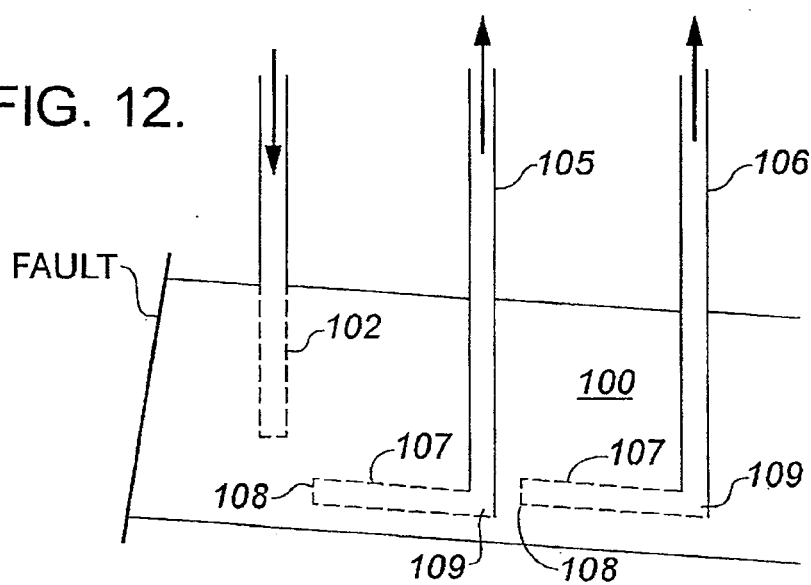
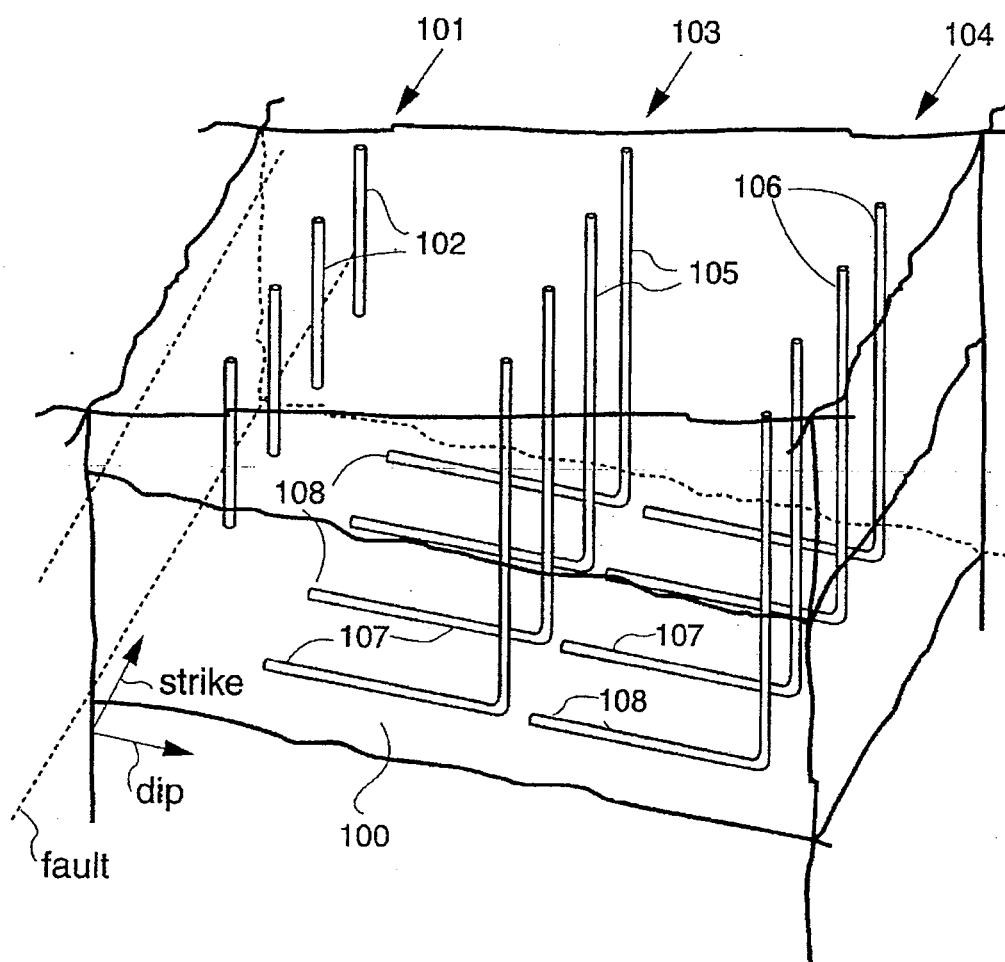
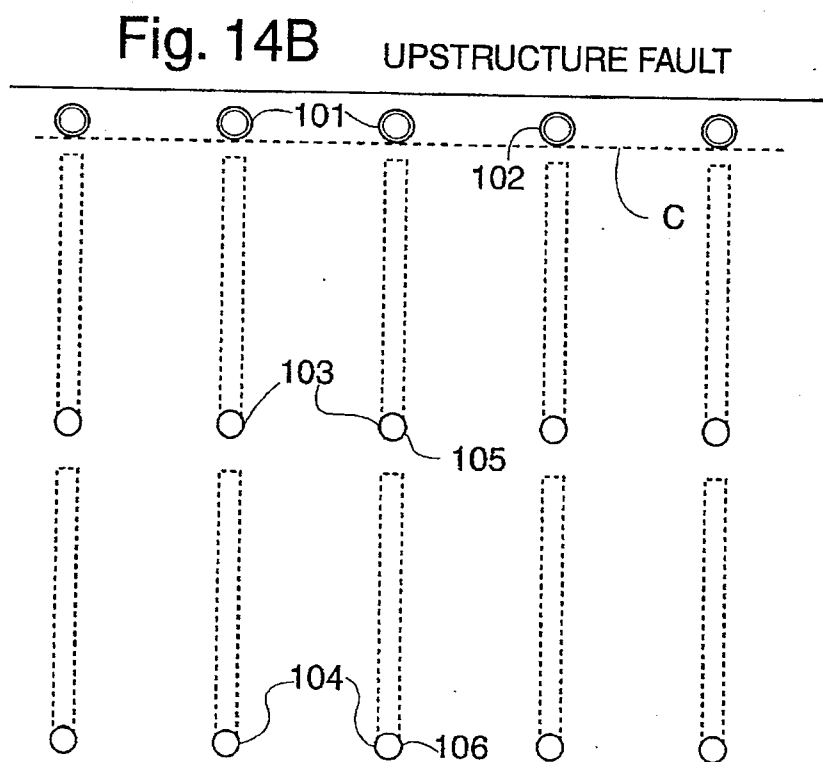
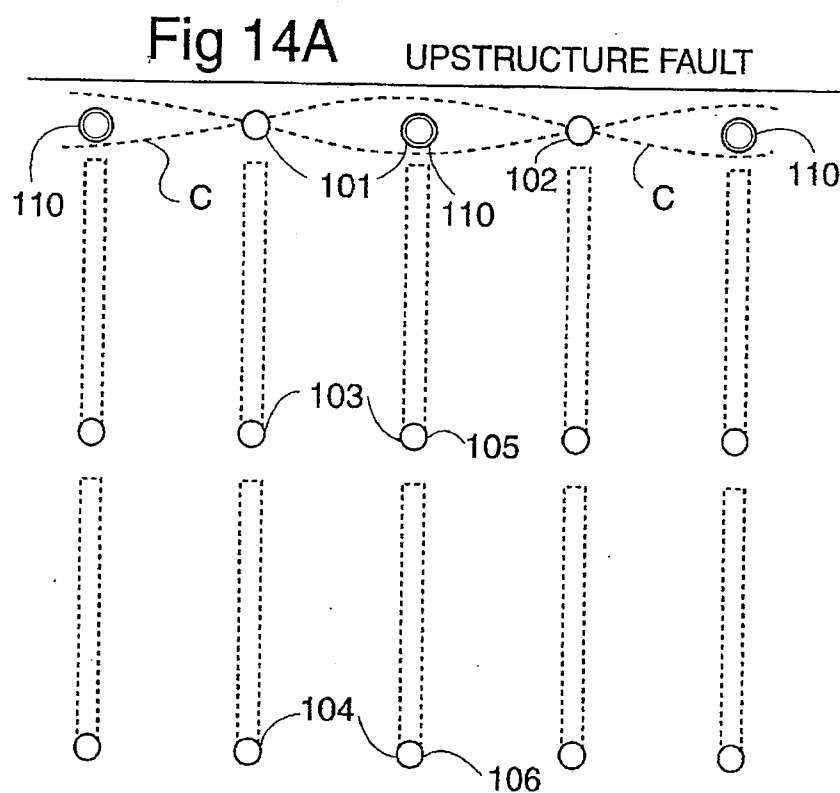
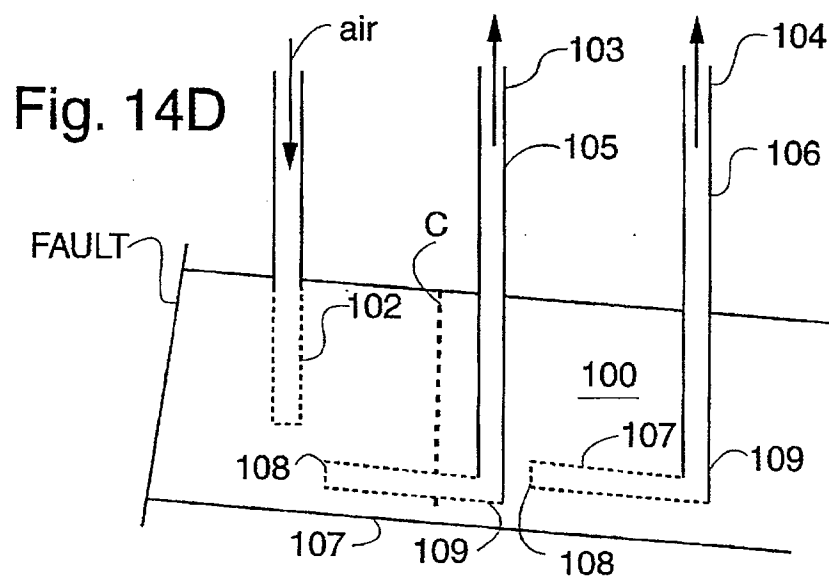
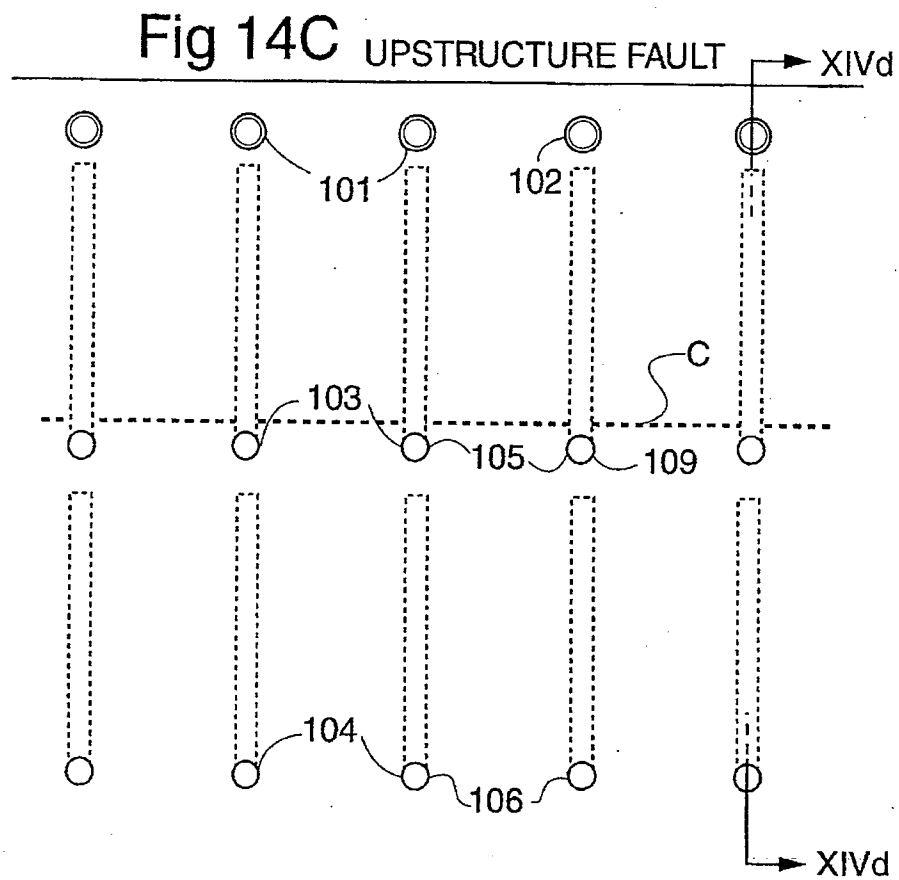
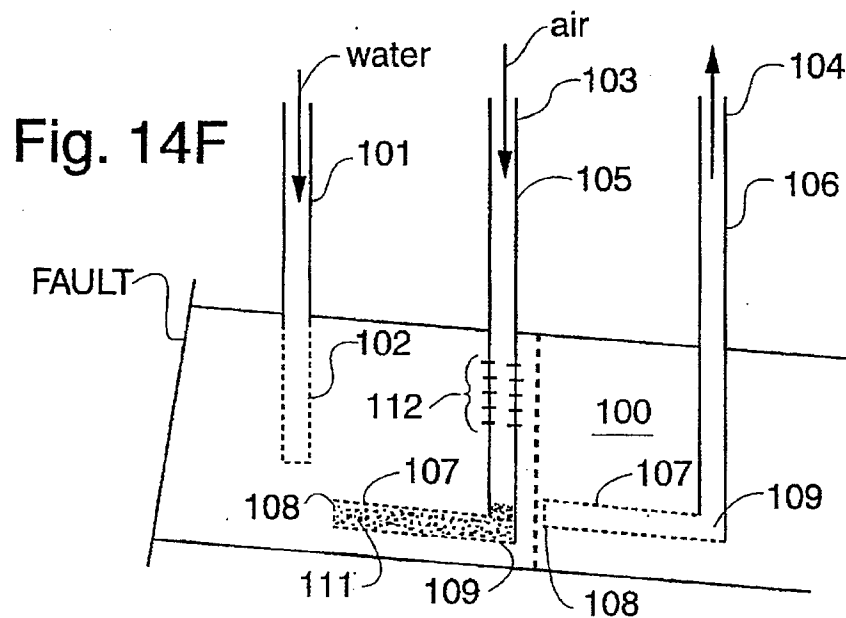
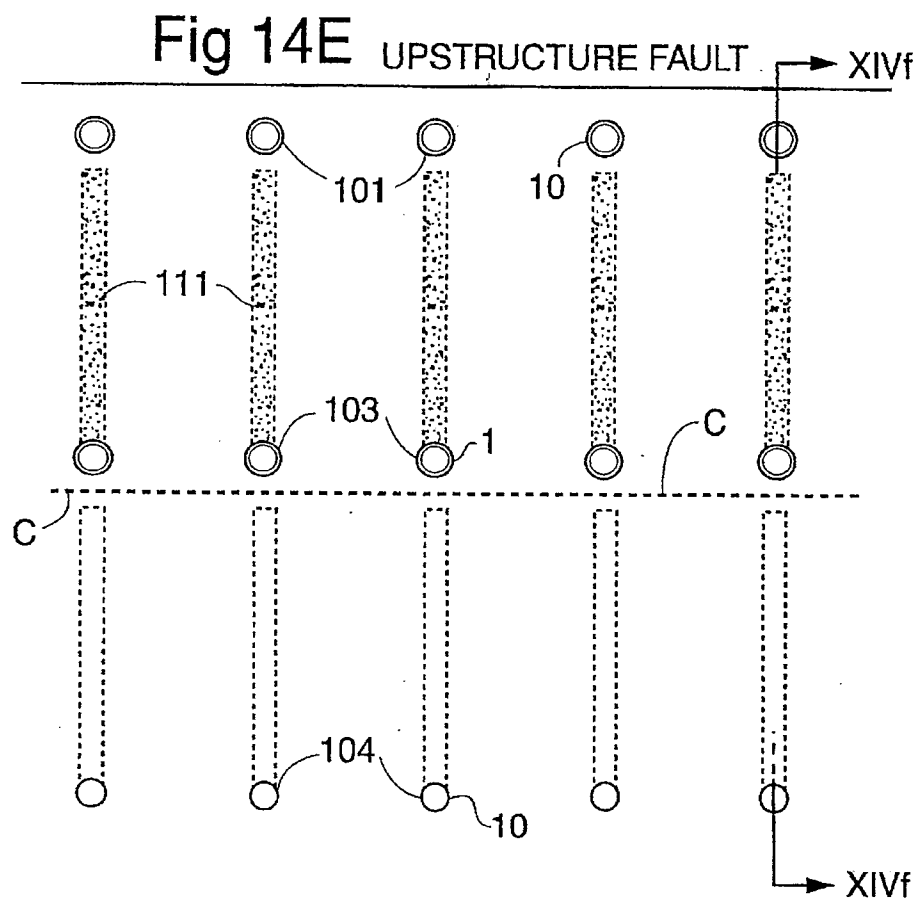


Fig. 13









OILFIELD IN-SITU COMBUSTION PROCESS

TECHNICAL FIELD

This invention relates to an in-situ combustion process for recovering hydrocarbons from an underground reservoir. More particularly, it relates to a process in which the production wells each have a horizontal leg and these legs are positioned perpendicularly to and in the path of a laterally extending and advancing combustion front.

BACKGROUND ART

In-situ combustion processes are applied for the purpose of heating heavy oil, to mobilize it and drive it to an open production well for recovery.

In general, the usual technique used involves providing spaced apart vertical injection and production wells completed in a reservoir. Typically, an injection well will be located within a pattern of surrounding production wells. Air is injected into the formation, the mixture of air and hydrocarbons is ignited, a combustion front is generated in the formation and this resulting combustion front is advanced outwardly toward the production wells. Or alternatively, a row of injection wells may feed air to a laterally extending combustion front which advances as a line drive toward a parallel row of production wells.

In both cases, the operator seeks to establish an upright combustion front which provides good vertical sweep and advances generally horizontally through the reservoir with good lateral sweep.

However, the processes are not easy to operate and are characterized by various difficulties.

One such difficulty arises from what is referred to as gravity segregation. The hot combustion gases tend to rise into the upper reaches of the reservoir. Being highly mobile, they tend to penetrate permeable streaks and rapidly advance preferentially through them. As a result, they fail to uniformly carry out, over the cross-section of the reservoir, the functions of heating and driving oil toward the production wells. The resulting process volumetric sweep efficiency is therefore often undesirably low. Typically the efficiencies are less than 30%.

It would therefore be desirable to modify the in-situ combustion technique so as to better control the way in which the combustion gases flow and the front advances, so as to increase the volumetric sweep efficiency. The work underlying the present invention was undertaken to reach this objective.

The invention, in its preferred form, incorporates aspects of two processes which are known in the art.

Firstly, it is known to initiate the combustion drive at the high end of a reservoir having dip and propagate the combustion front downstructure, isobath-wise. This procedure to some extent reduces the problem of gravity segregation of the combustion gases, because the gases are forced to displace the oil downward, in a gravity influenced, stable manner.

Secondly, Ostapovich et al, in U.S. Pat. No. 5,211,230, disclose completing a vertical air injection well relatively high in the reservoir and a horizontal production well relatively low in the reservoir. The production well is positioned transversely relative to the combustion front emanating from the injection well. The production well is spaced from the injection well. By implementing this arrangement, the combustion front follows a downward path, toward the low pressure sink provided by the produc-

tion well and the benefit of gravity drainage of heated oil is obtained. These effects enhance the sweep efficiency of the process and facilitate the heated oil reaching the production well. However, the premature breakthrough of the combustion front at a locus along the length of the transverse, horizontal leg will result in leaving an unswept reservoir zone between the leg's toe and the breakthrough locus.

The present invention will now be described.

SUMMARY OF THE INVENTION

In accordance with the preferred form of the invention, it has been determined that:

if a generally linear and laterally extending, upright combustion front is established and propagated high in an oil-containing reservoir; and

if an open production well is provided having a horizontal leg positioned low in the reservoir so that the well extends generally perpendicularly to and lies in the path of the front and has its furthest extremity ("toe") spaced from but adjacent to the injection source; then

the production well provides a low pressure sink and outlet that functions to induce the front to advance in a guided and controlled fashion, first towards the toe and then along the length of the horizontal leg—under these circumstances, the front has been found to remain generally stable and upright and is characterized by a relatively high sweep efficiency;

additionally, the air flows through the burnt out reservoir and through the upright combustion front, forming combustion gases (CO_2 , CO , H_2O) whose streamlines bend towards the horizontal leg, due to the downward flow gradient created by the action of the production well as a sink. An oil upgrading zone is formed immediately ahead of the front. The draining oil tends to keep the bore of the horizontal leg full, so there is little opportunity for unused oxygen to be produced through the production well until the front has advanced the length of the leg; and

as just stated, the heated oil drains readily into the production well for production therethrough.

When compared in experimental runs with a conventional procedure wherein spaced apart, simulated vertical air injection and production wells were completed in the same horizontal plane of the reservoir and a combustion front was initiated and propagated, the present invention was found to be relatively characterized by:

increased percentage of reservoir volume swept, increased recovery percentage of the oil in place, and increased average gravity of produced oil.

Additionally, the present procedure involving a horizontal producer, is found to be characterized by the advantage that the combustion front always intercepts the horizontal leg of the horizontal well at the toe point, rather than at a location along the length of the leg.

Up to this point, the invention has been described with reference only to a combustion process. As previously stated, an important feature of the invention is that the properly oriented, open horizontal leg of the production well functions to directionally guide and stabilize the advancing displacement front. There is a likelihood that this feature could beneficially be used with a steam, partially miscible gas drive or miscible solvent gas drive to control and stabilize the advancing displacement front which is functioning to reduce the viscosity of the oil directly in front of it.

Therefore, in broad terms, the invention is a process for reducing the viscosity of oil in an underground reservoir and driving it to a production well for recovery, comprising: providing a well, completed relatively high in the reservoir, for injecting a gaseous fluid into the reservoir to form an advancing, laterally extending displacement front operative to reduce the viscosity of reservoir oil; providing at least one open production well having a horizontal leg completed relatively low in the reservoir and positioned substantially perpendicular to and in the path of the advancing front; injecting the fluid through the well and advancing the displacement front along the leg; and producing the production well to recover oil from the reservoir.

DESCRIPTION OF THE DRAWINGS

FIGS. 1a and 1b are top plan and side views schematically showing a sand pack with simulated injection and production wells completed in a common horizontal plane, as was the case in experimental run 1-D reported on below;

FIGS. 2a and 2b are top plan and side views schematically showing a sand pack with simulated vertical injection well and perpendicular, horizontal production wells completed high and low in the pack, respectively, as was the case in experimental run 2-D reported on below;

FIG. 3 is a perspective view schematically showing a sand pack with a linear array of simulated injection wells and a simulated perpendicular, horizontal well, completed high and low respectively in the pack, as was the case in experimental runs 3-D and 4-W reported on below;

FIGS. 4a and 4b are top plan and side views schematically showing a staggered arrangement of simulated wells completed in the sand pack with a vertical injection well and a pair of parallel, spaced apart, perpendicular, horizontal wells, completed high and low respectively in the pack, as was the case in experimental run 5-D reported on below;

FIGS. 5a, 5b and 5c are top plan, side and end views of a test cell used in the experimental runs reported on below;

FIG. 6 is a flow diagram showing the laboratory set-up, including the test cell of FIGS. 5a-5c, used to conduct the experimental runs reported on below;

FIGS. 7a and 7b are isotherm maps developed in the sand pack during run 1-D (prior art configuration), taken along the horizontal and vertical mid-planes respectively;

FIGS. 8a and 8b are the isotherm maps developed in the sand pack during run 2-D, taken along the horizontal and vertical mid-planes respectively;

FIGS. 9a and 9b are the isotherm maps developed in the sand pack after 45 minutes of combustion during run 3-D, taken along horizontal planes close to the top and bottom of the pack, respectively;

FIGS. 9c, 9d, 9e and 9f are the isotherm maps developed in the sand pack along the vertical mid-plane after 45, 240, 360 and 460 minutes of combustion, respectively, during run 3-D;

FIG. 10 is a plot showing the cumulative production of the oil in place (expressed in percent) for runs 1-D, 2-D and 5-D;

FIG. 11 is a plan view showing a preferred field embodiment of the well layout;

FIG. 12 is a side cross-section of the well arrangement of FIG. 11.

FIG. 13 is a perspective view of the reservoir in the injection well and production well layout; and

FIGS. 14a, 14b, 14c, 14d, 14e and 14f illustrate various phases of the combustion process according to the layout shown in FIGS. 11 and 12.

BEST MODE OF THE INVENTION

The invention was developed in the course of carrying out an experimental investigation involving test runs carried out in a test cell or three dimensional physical model.

More particularly, a test cell 1, shown in FIGS. 5a, 5b, 5c and 6, was provided. The cell comprised a rectangular, closed, thin-walled stainless steel box 2. Dimension-wise, the box 2 formed a chamber 3 having an area of 40 square centimetres and height of 10 centimetres. The thickness of each box wall was 4 millimetres. The chamber 3 was filled with a sand pack 4 consisting of a mixture of sand, oil and water. The composition of the uniform mixture charged into the chamber 3 was:

sand- 83-87 wt. %

oil- 11-14 wt. %

water- 2-3 wt. %

The porosity of the sand pack 4 was about 30% and the permeability was about 10 darcys.

The loaded cell box 2 was placed inside a larger aluminum box 5 and the space between them was filled with vermiculite powder insulation.

Sixty type K thermocouples 6, positioned at 6 cm intervals as shown in FIGS. 5a, 5b, 5c and 6, extended through the wall of the cell 1 into the sand pack 4, for measuring the three dimensional temperature distribution in the sand pack 4.

To compensate for heat losses, the cell 1 was wound with heating tape (not shown). This heat source was controlled manually, on demand, in response to the observed combustion peak temperature and adjacent wall temperature values. The temperature at the wall of the cell was kept a few degrees ° C. less than the temperature inside the sand, close to the wall. In this way, the quasi-adiabatic character of the run was assured.

A cell heater 7 was embedded in the top section of the sand pack 4 at the air injection end, for raising the temperature in the region of the injection well 8 to ignition temperature.

One or more simulated air injection wells 8 were provided at the injection end of the cell 1. A simulated production well 9 was provided at the opposite or production end of the cell 1.

The positioning and vertical or horizontal disposition of the wells 8, 9 are shown schematically in FIGS. 1a, 1b, 2a, 2b, 3, 4a and 4b for the five test runs reported on below.

As shown in FIGS. 1a, 1b for run 1-D, the air injection and production wells 8, 9 were short and coplanar. They were both completed under the horizontal mid-plane of the sand pack 4. This arrangement simulated vertical injection and production wells completed at about the same depth. As shown in FIGS. 2a, 2b for run 2-D, the air injection well 8 was short and positioned relatively high in the sand pack 4. The production well 9 was horizontal, elongated, positioned low in the sand pack 4 relative to the injection well 8 and positioned with its toe 10 adjacent to but spaced from the injection well. As shown in FIG. 3 for runs 3-D and 4-W, a row 11 of vertical injection wells 8, positioned laterally across the sand pack 4, were provided. The injection wells were located relatively high in the sand pack. The production well 9 was horizontal, elongated, positioned low in the sand pack and had its toe adjacent to but spaced from the injection wells. As shown in FIGS. 4a, 4b for run 5-D, a single vertical air injection well 8 was provided high in the sand pack 4 and a pair of horizontal production wells 9 were provided low in the pack. The production wells were laterally spaced relative to the injection well, to provide a staggered line drive system.

All of the horizontal production wells 9 were arranged to be generally perpendicular to a laterally extending combustion front developed at the injection source. However, the toe 10 of the production well was spaced horizontally away from a vertical projection of the injection well.

Each of the injection and production wells 8, 9 were formed of perforated stainless steel tubing having a bore 4 mm in diameter. The tubing was covered with 100 gauge wire mesh (not shown) to exclude sand from entering the tubing bore.

The combustion cell 1 was integrated into a conventional laboratory system shown in FIG. 6. The major components of this system are now shortly described.

Air was supplied to the injection well 8 from a tank 19 through a line 20. The line 20 was sequentially connected with a gas dryer 21, mass flowmeter 22 and pressure gauge 23 before reaching the injection well 8. Nitrogen could be supplied to the injection well 8 from a tank 24 connected to line 20. Water could be supplied to the injection well 8 from a tank 27 by a pump 25 through line 26. Line 26 was connected with line 20 downstream of the pressure gauge 23. A temperature controller 28 controlled the ignition heater 7. The produced fluids passed through a line 30 connected with a separator 31. Gases separated from the produced fluid and passed out of the separator 31 through an overhead line 32 controlled by a back pressure regulator 33. The regulator 33 maintained a constant pressure in the test cell 1. The volume of the produced gas was measured by a wet test meter 34 connected to line 32. The liquid leaving the separator was collected in a cylinder 40.

Part of the produced gas was passed through an oxygen analyzer 36 and gas chromatograph 37. Temperature data from the thermocouples 6 was collected by a computer 38 and gas composition data was collected from the analyzer 36 and gas chromatograph 37 by an integrator 39.

Air was injected at a rate of approximately 0.243 sm³/hr. and ignition was initiated using the heater 7. The tests were typically continued for up to 22 hours. In the run where water was added, its rate was approximately 0.43 kg/hr.

Following completion of each run, an analysis of the cell sand pack 4 was undertaken to determine the volumetric sweep efficiency. The analysis comprised a physical removal of successive vertical layers of the sandpack at 3 cm intervals and determining the extent of the burned zone by measuring the oil and coke content. In this way the volumetric sweep of the burning front was determined post-mortem and compared with that obtained from the peak temperature profiles during the run.

The relevant results for the runs are set forth in Table I.

TABLE I

Run	Con-figuration	Volume Swept %	Air-Oil Ratio (SM ³ /M ³)	Average Gravity (°API) Of Produced Oil
1-D	FIG. 1	58.7	2045	14
2-D	FIG. 2	53.0	1960	19-21
3-D	FIG. 3	66	—	19-21
4-W	FIG. 3	77	923	19-21
5-D	FIG. 4	69.5	1554	15

Legend:

D = dry in situ combustion

W = moderate wet combustion

FIGS. 7a and 7b show the isotherm or temperature contour maps developed along the horizontal mid-plane and the central vertical mid-plane, respectively, in the sand pack after 930 minutes of combustion during run 1-D, using the

well configuration of FIGS. 1a and 1b. (This run was carried out using conventional vertical well placement.)

The nature and extent of the volume swept by the combustion front is indicated by the isotherms. It will be noted that, in the plan view of FIG. 7a, the combustion front was relatively narrow towards the production well side. Large volumes of oil were left substantially unheated on each side of the sand pack. On the other hand, the central vertical mid-plane isotherms in FIG. 7b show that the leading edge of the maximum recorded temperature (>350° C.), in the region closed to the production well, is already located in the upper third of the layer. These results are indicative of gas override.

FIGS. 8a and 8b show isotherm maps developed along the horizontal mid-plane and the central vertical mid-plane, respectively, in the sand pack after 999 minutes of combustion during run 2-D, using the well configuration of FIGS. 2a and 2b. As shown, the isotherms indicate that the combustion front was substantially wider than that of Run 1 and more upright.

FIGS. 9a and 9b show isotherm maps developed along horizontal planes at the top and bottom of the sand pack after 45 minutes of combustion during Run 3-D, using the well configuration of FIG. 3. FIGS. 9c, 9d, 9e and 9f show isotherm maps developed along the central vertical plane of the sand pack after 45, 240, 360 and 460 minutes respectively. The isotherms demonstrate that the combustion front generated by the row of injection wells extended laterally, remained generally linear and was generally upright throughout the test. Stated otherwise, the lateral and vertical sweep was much improved relative to that of Run 1-D. This run 3-D demonstrated the preferred form of the invention.

In the preferred field embodiment of the invention, illustrated in FIGS. 11 and 12 and 13, a reservoir 100 is characterized by a downward dip and lateral strike. A row 101 of vertical air injection wells 102 is completed high in the reservoir 100 along the strike. At least two rows 103, 104 of production wells 105, 106, having generally horizontal legs 107, are completed low in the reservoir and down dip from the injection wells, with their toes 108 closest to the injection wells 102. The toes 108 of the row 103 of production wells 105 are spaced down dip from a vertical projection of the injection wells 102. The second row 104 of production wells 106 is spaced down dip from the first row 103. Generally, the distance between wells, within a row, is considerably lower than the distance between adjacent rows.

The phases of the process are set forth in FIGS. 14a-14f and are described as follows. In the first phase of the process (FIG. 14a), a generally linear combustion front C is generated in the reservoir 100 by injecting air through every second well 110 of the injection wells 102. Preferably a generally linear lateral combustion front is developed by initiating combustion at every second well 110 and advancing these fronts laterally until the other unused wells 102 are intercepted by the combustion front C and by keeping the horizontal production wells 105, 106 closed. Then, air is injected through all the wells 102 (FIG. 14b) in order to link these separate fronts to form a single front C. The front C is then propagated down dip (FIGS. 14c, 14d) toward the heel 109 of the first row 103 of production wells 105. The horizontal legs 107 of the production wells 105 are generally perpendicular to the front C. The production wells 105 are open during this step, to create a low pressure sink to induce the front to advance along their horizontal legs 107 and to provide an outlet for the heated oil. When the front C approaches the heel 109 of each production well 105, the well is closed in. The horizontal legs 107 of the closed-in

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wells 105 are then filled with cement 111 (FIG. 14e). The wells 105 are then perforated 112 high in the reservoir 100 (FIG. 14f) and converted to air injection, thereby continuing the propagation of a combustion front toward the second row 104 of production wells 106. Preferably, the first row 101 of injection wells is converted to water injection, for scavenging heat in the burnt out zone and bringing it ahead of the combustion zone. This process is repeated as the front progresses through the various rows of production wells.

By the practise of this process, a guided combustion front is caused to move through the reservoir with good volumetric sweep efficiency.

The embodiments of the invention in which an exclusive property or privilege is claimed are defined as follows:

1. A process for reducing the viscosity of oil and recovering it from an underground oil-containing reservoir, comprising:

providing an injection well, completed relatively high in the reservoir, for injecting a gaseous fluid into the reservoir to form an advancing, laterally extending displacement front operative to reduce the viscosity of reservoir oil;

providing at least one open production well having a horizontal leg completed relatively low in the reservoir and positioned substantially perpendicular to and in the path of the advancing displacement front;

injecting the fluid through the injection well and advancing the displacement front along the leg; and

producing the production well to recover reduced-viscosity oil from the reservoir.

2. An in-situ combustion process for recovering oil from an underground oil-containing reservoir, comprising:

providing a generally linear air injection source completed relatively high in the reservoir;

providing at least one open production well comprising a horizontal leg having a toe and heel and being completed relatively low in the reservoir and positioned generally perpendicularly to the injection source so as to lie in the path of a combustion front established by the source;

injecting air through the injection source and initiating and propagating a combustion front, extending laterally

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of the production well horizontal leg, so that it advances toward and along the leg; and

producing the production well to recover heated oil from the reservoir.

3. The process as set forth in claim 2 wherein:

the air injection source comprises a generally linear array of vertical injection wells and the toe of the horizontal leg is adjacent to but offset from the injection wells.

4. The process as set forth in claim 2 or 3 wherein:

the reservoir extends downwardly at an angle to have dip and strike;

the injection source extends generally along the strike and the horizontal leg of the production well extends along the dip.

5. The process as set forth in claim 3 wherein:

the reservoir extends downwardly at an angle to have dip and strike;

a plurality of production wells as aforesaid are provided, said production wells being arrayed in at least two spaced apart rows parallel with the array of injection wells, which are located at the uppermost part of the oil reservoir; and

the rows of injection wells and production wells extend along the strike and the horizontal legs of the production wells extend along the dip.

6. The process as set forth in claim 5 comprising:

closing each production well in the first row as the combustion front approaches the heel of its horizontal leg;

filling the horizontal legs of the closed production wells in the first row with cement, re-completing the wells high in the reservoir and converting them to air injection wells; and

initiating air injection through the converted wells to advance a combustion front toward the second row of production wells and along their horizontal legs.

7. The process as set forth in claim 6 comprising:

injecting water through the array of original air injection wells in the course of injecting air through the converted wells.

* * * * *

Disclaimer

5,626,191—Malcolm Greaves, Avon, United Kingdom; Alexandru T. Turta, Calgary, Canada. OILFIELD IN-SITU COMBUSTION PROCESS. Disclaimer filed February 2, 2002, by assignee, Alberta Research Council Inc.

Hereby enters this disclaimer to claim 1.

(Official Gazette, March 26, 2002.)

United States Patent [19]

Shu et al.

[11] Patent Number: 4,598,770

[45] Date of Patent: Jul. 8, 1986

[54] THERMAL RECOVERY METHOD FOR VISCOUS OIL

[75] Inventors: Winston R. Shu, Dallas; Kathy J. Hartman, Arlington, both of Tex.

[73] Assignee: Mobil Oil Corporation, New York, N.Y.

[21] Appl. No.: 664,740

[22] Filed: Oct. 25, 1984

[51] Int. Cl.⁴ E21B 43/24

[52] U.S. Cl. 166/245; 166/50; 166/52; 166/272

[58] Field of Search 166/272, 263, 303, 50, 166/52, 245

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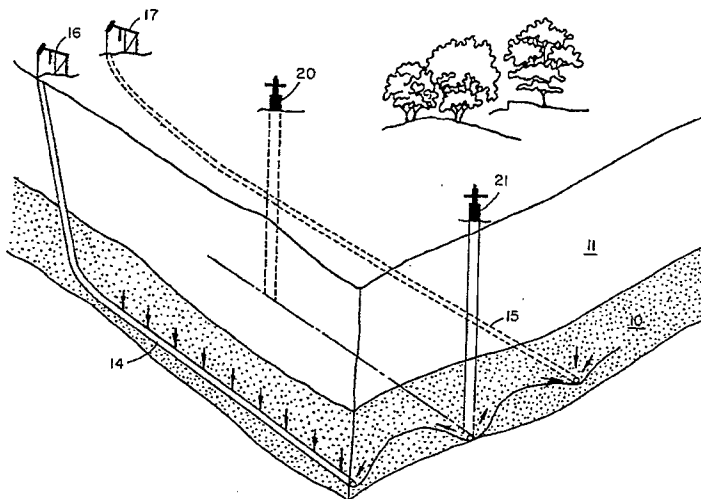
Primary Examiner—Stephen J. Novosad

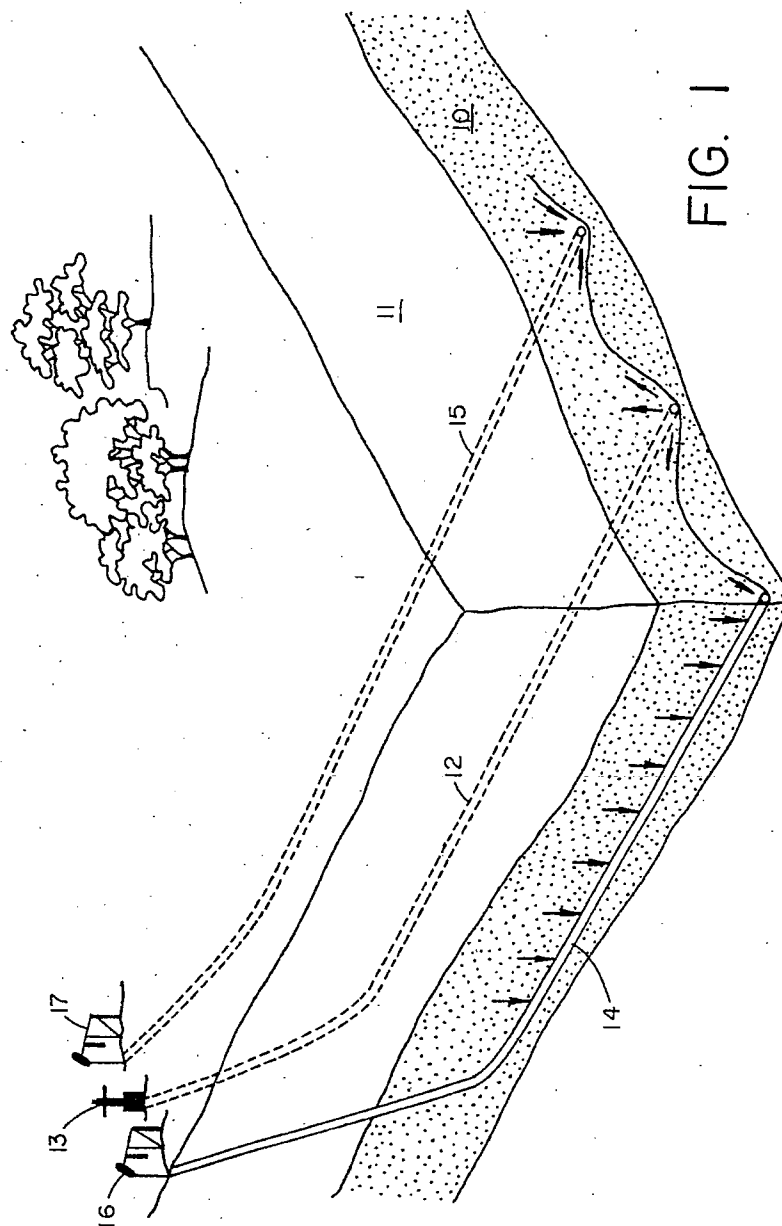
Attorney, Agent, or Firm—A. J. McKillop; Michael G. Gilman; George W. Hager, Jr.

[57] ABSTRACT

A thermal oil recovery process in which steam is injected into a heavy oil-bearing formation through a horizontally-drilled injection well and oil is produced through a horizontal production well parallel to the injection well.

2 Claims, 5 Drawing Figures





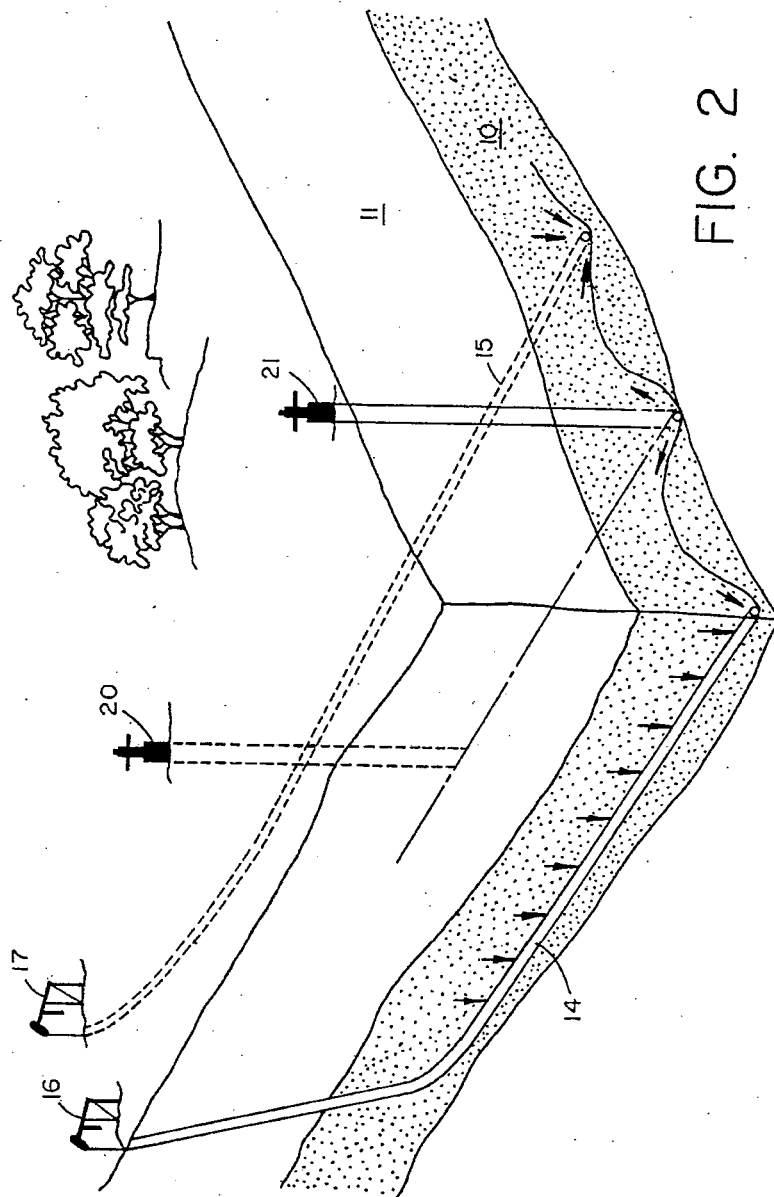


FIG. 3

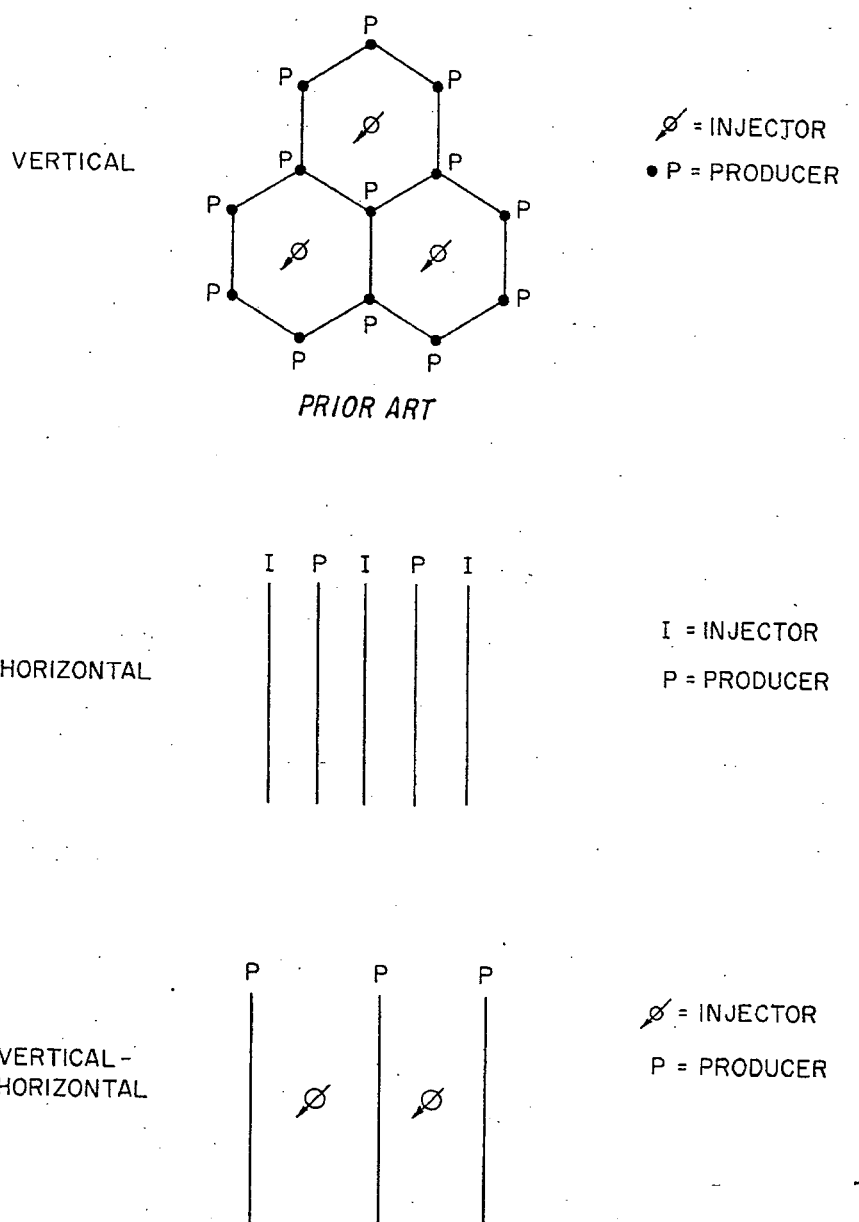
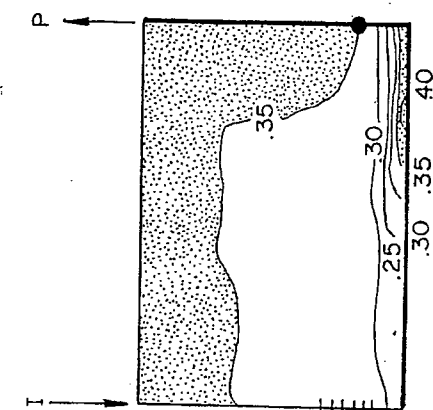
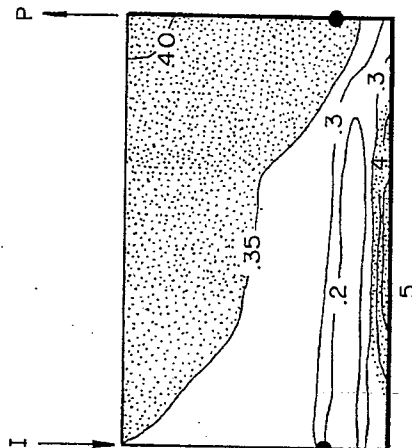


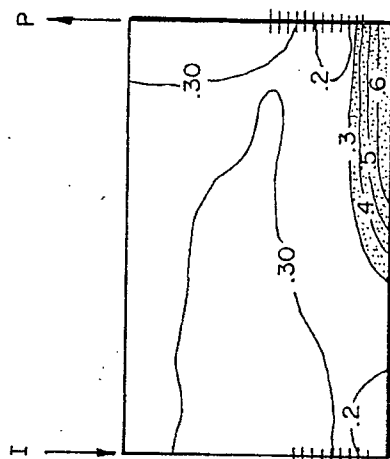
FIG. 4



VERTICAL
HORIZONTAL WELL COMBINATION
AT 1290 DAYS

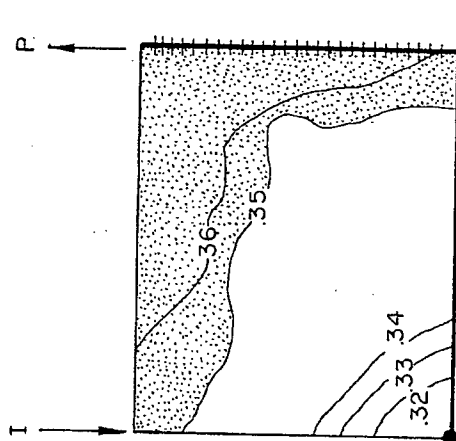


PARALLEL HORIZONTAL WELLS
AT 1290 DAYS

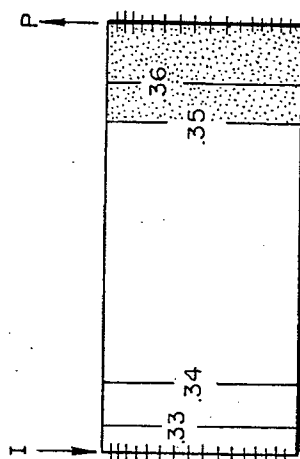


VERTICAL WELLS
AT 1470 DAYS

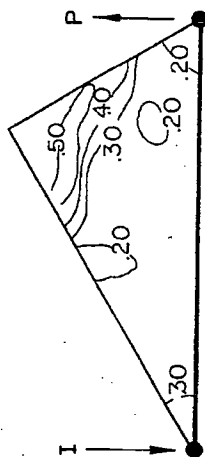
FIG. 5



VERTICAL
HORIZONTAL WELL COMBINATION
AT 1290 DAYS



PARALLEL HORIZONTAL WELLS
AT 1290 DAYS



VERTICAL WELLS
AT 1470 DAYS

THERMAL RECOVERY METHOD FOR VISCOUS OIL

FIELD OF THE INVENTION

This invention relates to a thermal recovery process for recovering viscous oils from subterranean formations. In particular, the invention relates to an improved steam flooding method for recovering such oils.

BACKGROUND OF THE INVENTION

There are many subterranean formations containing heavy, i.e. viscous, oils from which the oil cannot be recovered by conventional methods because the oil is too viscous to flow to the production wells without some form of assistance. Such formations are known to exist in the major tar sand deposits of Alberta, Canada and Venezuela with lesser deposits elsewhere, for example, in California, Utah and Texas. The API gravity of the oils in these deposits typically ranges from 10° to 6° in the Athabasca, Alta. deposits to even lower values in the San Miguel sands in Texas, indicating that the oil is of a highly viscous nature.

Various methods have been proposed for recovering the oil in these deposits now that reserves of more easily recovered oils are decreasing, at least in the politically stable areas of the world. These methods include in-situ combustion methods in which part of the oil in the reservoir is burnt by the injection of air or oxygen through an injection well to generate heat so as to reduce the viscosity of the oil and to produce a degree of cracking; the resulting less viscous, cracked oil then acts as a solvent for the heavy oil in place. Solvent recovery techniques have also been proposed, for example in U.S. Pat. Nos. 4,373,585 and 4,293,035, in which a solvent for the heavy oil is injected into the reservoir to form a less viscous solution which can then be recovered by more conventional means. Another technique which has been proposed and used in various forms is steam flooding, in which steam is injected into the formation through an injection well, to heat the formation and, in so doing, to reduce the viscosity of the oil and possibly also, to induce a degree of cracking, resulting in a further reduction in viscosity. Processes of this type can be generally classified as basically of the two well or one well type. In the two well or steam drive type, the steam is injected through an injection well and the injected steam serves to drive the oil towards a separate production well which is located at some horizontal distance (offset) from the injection well. In the one-well or "huff and puff" type operation, a single well is used for both injection and production. The steam is first injected to reduce the viscosity of the oil and to pressurize the formation; after a certain amount of time, steam injection is terminated and the well is turned over to production. A soak period may be allowed to permit the heat to permeate the reservoir to a greater extent before production is initiated in either type of operation. Whether the process is classified as of the one-well or two well types, the well arrangement can, of course, be repeated to cover the field in the manner desired. For example, the two well arrangement may be repeated in regular patterns such as the inverted five spot or inverted seven spot patterns, as described in U.S. Pat. No. 3,927,716. The present method relates basically to the two well type operation, using an injection well or wells and a

separate production well or wells at an offset from the injection well.

Horizontally drilled wells have been proposed in various applications, for example, in solvent recovery processes, as described in U.S. Pat. No. 4,385,662 as well as for offshore primary recovery operations as described, for example, in Ocean Industry, June 1984, 35-36 and in certain steam flooding operations mentioned in the Ocean Industry article.

Among the steam flooding operations using horizontal wells are the Kern River, California "huff and puff" project described in the Oil and Gas Journal, 23 August 1982, 51-54, this project also including conventional vertical steam injection wells bisecting the lateral wells. The Cold Lake, Alta. project which used horizontal wells is believed to be of the single well ("huff and puff") type also; the project has been described in Paper No. 79-30-10 of the Petroleum Society of CIM, presented in Banff, Alta. 8-11 May 1979. A similar project was operated at Fort McMurray, Alta, as described in Paper No. 82-33-68 of the Petroleum Society of CIM, presented 6-9 June 1982 in Calgary, Alta., Petroleum Engineer International, September 1982, 40-52. In addition, U.S. Pat. No. 4,248,302 discloses a steam flood recovery method using a highly deviated injection well with production wells situated along the line of the injection well. This proposal has the disadvantages that not only is a relatively large number of production wells required but, in addition, correct positioning of these wells over the injection points is difficult.

Steam flooding processes using horizontal fractures for injecting the steam have been proposed in U.S. Pat. Nos. 3,375,870 and 4,265,310.

U.S. Pat. No. 4,466,485 describes a viscous oil recovery method which employs a steam injection well which extends through the formation in a horizontal direction. The production well is in the conventional vertical position and is completed in the upper two-thirds of the formation. A particular production cycle is employed to maximize recovery but because of the vertical disposition of the production wells, complete drainage of the formation is not assured.

SUMMARY OF THE INVENTION

According to the present invention, viscous oils are recovered from subterranean formations by a steam flooding operation using at least one horizontally drilled production well. The steam may be injected either through injection wells arranged vertically in the conventional manner, at an offset from the horizontal production well or, alternatively, a horizontal injection well may be used. Generally, it is preferred that the injection wells should be arranged along a line between two of the horizontal production wells in order to achieve maximum steam utilization and to optimize reservoir drainage into the production wells. The production wells will normally be situated near the bottom of the production interval to ensure that drainage is as complete as possible, thereby maximizing recovery.

DRAWINGS

FIG. 1 is a simplified representation of a recovery operation using horizontal injection and production wells;

FIG. 2 is a simplified representation of a recovery operation using horizontal production wells and vertical injection wells;

FIG. 3 is a schematic showing the well patterns used in the experimental simulations described below;

FIG. 4 is a comparison of the residual oil saturations obtained with the simulated production runs described below (vertical contours);

FIG. 5 is a comparison of the residual oil saturations obtained with the simulated production runs described below (horizontal contours).

DETAILED DESCRIPTION

FIG. 1 shows the preferred well pattern for carrying out the present production method. A subterranean heavy oil formation 10 underneath an overburden 11 has a horizontal steam injection well 12 extending from surface injection head 13 in a substantially straight line along the bottom of the production interval. Two horizontal production wells 14, 15 also run through reservoir 10 at the bottom of the production interval, with their horizontal portions parallel to injection well 12. At the surface, the production wells are connected to suitable wellhead equipment 16, 17 for producing the fluids which enter the wells.

In operation, steam is injected into injection well 12 and thence into formation 10 where it heats the formation and the oil in place in the reservoir to the appropriate temperature for recovery through the production wells.

An alternative arrangement is depicted in FIG. 2 in which vertical steam injection wells 20, 21 are disposed along a line parallel to and centrally between horizontal production wells 14, 15. The injector wells are completed at the bottom of the production interval and the horizontal production wells again, run along the bottom of the production interval. Wellhead equipment 16, 17 is provided as previously described.

Because the steam from the injector wells tends to rise in the reservoir after it leaves the injection well, the injection wells should preferably be completed in the lower portion of the production interval. However, to minimize heat losses to the non-pay zone beneath and to minimize channelling of steam under the pay zone, it may be desirable to position the horizontal injection well or to complete the vertical injection well, as appropriate, somewhat above the bottom of the production interval; e.g. at 80% or 90% of the vertical distance down the interval. Because the oil which has been heated by the steam will descend through the reservoir, taking with it some of the oil in place, positioning the injector at some distance up in the reservoir will not necessarily lose production because the descending, heated oil, together with entrained reservoir oil, will drain into the production wells at the bottom of the interval. Thus, the use of the horizontal producing wells establishes a vertical sweep of high efficiency in the reservoir. Area sweep may be up to almost 100 percent because of the greater reservoir area exposed to the producing wells.

The horizontal separation or offset between the line of injectors and the production wells needs to be chosen according to reservoir characteristics; e.g. nature of oil, matrix porosity, permeability and so forth. This may be determined by reference to the known characteristics of the reservoir prior to siting the wells. The well pattern may, of course, be repeated in order to cover the production field to the extent desired. Generally, it has been found that one horizontal well can replace about 2.5 to 3.8 vertical wells in a parallel horizontal injector/producer pattern, depending upon the vertical per-

meability of the formation; in a vertical injector/horizontal producer operation, one horizontal well can generally replace about 1.6 to 2.4 vertical producers. In an infinitely repeated vertical injector/horizontal parallel producer pattern, the injectors should be situated on the center line between the parallel producers with a separation equal to the separation between the producers. In this case, therefore, the number of vertical injectors between each pair of producers will be equal to the quotient of the length of the horizontal producers and their separation. The economics of the operation should therefore be considered at the outset since horizontal wells are more expensive to drill than vertical wells. The advantages of horizontal wells over vertical wells increase with an increasing ratio of vertical to horizontal permeability for the reservoir: as the ratio increases, residual oil saturation in the upper part of the reservoir will decrease, to give a better vertical sweep efficiency resulting from the improved drainage into the production wells.

Operating conditions for the steam flooding process should be chosen in accordance with known reservoir characteristics such as permeability, nature of oil and so forth. The operating procedure may follow conventional principles or may be adjusted suitably to take the greatest opportunity of exploiting the advantages of the present invention. For example, steam injection rates may typically be from 1.5 to 2.0 barrels/day/acre-foot CWE (cold water equivalent) (from about 385 to 260 l./day/1000 m³ CWE). Total amount of steam injected will depend primarily on reservoir thickness, temperature and thermal conductivity together with the characteristics of the oil; e.g. the extent to which it is affected physically and chemically by the steam. Typically, steam temperature will be from 200° to 400° C. (about 400° to 750° F.); temperatures at the higher end of this range will generally tend to promote cracking of the oil in the reservoir to produce a vis-broken oil of low viscosity which facilitates an enhanced degree of recovery of the reservoir oil, as compared to a non-visbroken oil that has merely been subjected to heating by lower temperature steam. Steam temperature is determined by its pressure of injection which, in turn, will depend upon the reservoir characteristics; e.g. reservoir pressure and can be readily determined. Steam quality may also be selected according to the desired amount of net heat to be injected but normally should lie between 0.4 to 0.8 for a safe and efficient operation of the steam generator.

The production operations may be run with either rate control or pressure control. In the former, a predetermined liquid flow rate is maintained by adjusting the bottomhole pressure at the injector. With pressure control, free flow of liquids is allowed by maintaining constant bottomhole pressure, assuming that pump capacity is adequate to remove all the fluids produced. Depending upon reservoir characteristics, it may be more advantageous to operate with rate control in order to achieve maximum production, although it may take longer to do it; the economics of the individual modes of operation should therefore be given appropriate consideration in each case.

Experimental

Vertical Well Pattern

Using computer modelling techniques, a reservoir volume equivalent to about one-twelfth of an infinitely

repeated seven spot vertical well pattern was simulated, as shown in FIG. 3. The model therefore assumed use of 1/12 of the injector and 1/6 of a producer. The equivalent area for the pattern was 6.9 acres (2.8 ha) thus giving a simulated area of 0.575 acre (0.23 ha), at a well distance of 341 ft (104 m).

The injector was completed in the 195 ft. (59 m) pay zone for an interval of 60 ft (18.3 m) and the producer 90 ft (27.4 m), each starting just above a 15 ft (4.6 m) water layer ($S_w=0.81$). Initial reservoir temperatures were 60° C. (140° F.) and 790 kPa (100 psig), respectively.

Steam of 60% quality was injected at 285° C. (545° F.) and 3200 kPa (450 psig), respectively, at an injection rate of 376 hl/day (237 bbl/day) for one-twelfth of an injector. The production well was placed on rate control with a maximum liquid rate of 477 hl/day (300 bbl/day), equivalent to 211 l/day/1000 m³ (1.65 bbl/day/acre-foot).

Criteria used for determining the time of steam breakthrough were: live steam production, a significant drop in the oil production rate and a significant increase in the water:oil ratio (water:oil greater than 20:1).

Horizontal Well Pattern

A parallel horizontal well pattern, i.e., an infinitely repeated pattern of injectors and producers horizontal and parallel to one another, as shown in FIG. 3, of equivalent surface area to 1/6 of the vertical well pattern, using the same well separation of 104 m (341 ft). The resulting length of horizontal well simulated was therefore 45.3 m (148.5 ft). To cover an area equivalent to the entire seven spot vertical pattern, the horizontal wells would be six times as long, about 271 m (891 ft). The horizontal wells were placed 12 m (40 ft) from the bottom of the pay zone.

The injection of steam was simulated using the same conditions as for the vertical well pattern.

For simulation purposes, the horizontal well pattern was tested with both rate control and pressure control.

Vertical-Horizontal Well Combination

An infinitely repeated well pattern having vertical injection wells and horizontal producers, as shown in FIG. 3, was also simulated. In this case, simulated area was equivalent to one quarter of the 7-spot vertical pattern, using a horizontal offset of 90 m (295 ft) between the vertical injector and the horizontal producer. The vertical well was completed for 18.3 m (60 ft) in the pay zone, as in the vertical well situation, and the horizontal well was situated 10.7 m (35 ft) above the water layer. The length of the horizontal well in the simulated area was about 152 m (500 ft).

Steam injection was simulated under the same conditions as for the other cases, using both rate and pressure control. The results are given in Table 1 below.

TABLE 1

Comparison of Well Patterns			
Pattern	Vertical	Horizontal	Vertical-Horizontal
Breakthrough Time, Days	1470	1290	1290
Injection, MBBL	3862	3471	3672
Production			
Oil, MBBL	575.0	481.4	455.6
Oil, %	33.5	28.0	26.5

TABLE 1-continued

Comparison of Well Patterns			
Pattern	Vertical	Horizontal	Vertical-Horizontal
Water, MBBL	4175.4	4053	4232
Ratios			
Oil/Steam	0.149	0.139	0.124
Cumulative Water/Oil	7.26	8.42	9.29

Notes:

- (1) Injection and Production figures on equivalent 7-spot acreage basis.
- (2) Percentage oil produced is percentage of original oil in place.
- (3) Results for horizontal and vertical/horizontal patterns are on pressure control.

With the parallel horizontal well pattern under pressure control, breakthrough occurred, as shown in Table 1 at 1290 days. Under rate control, breakthrough occurred later (at 1470 days) but gave a higher total oil recovery, indicating that for the reservoir studied there is likely to be an optimum production rate between the cases considered in this study.

With the vertical/horizontal well pattern, a similar result was obtained in the comparison between rate and pressure control.

Comparison of the residual oil saturation contour plots at steam breakthrough shown in FIGS. 4 and 5 indicates that each type of well pattern has a different sweep pattern. FIG. 4 compares the oil saturation contours showing the vertical sweep in the plane which contained the vertical injector. All well patterns had poor vertical sweep in areas beneath the production well elevation. The vertical well pattern had excellent vertical sweep with steam overriding and pushing oil over and down to the producer. The parallel horizontal wells had less steam override and less recovery from the upper portion of the reservoir. The vertical-horizontal well combination showed an intermediate vertical sweep with more override near the vertical injector and less near the horizontal producer.

FIG. 5 illustrates the area sweep in the horizontal plane which contained the horizontal wells, at steam breakthrough. The vertical wells left some unswept oil between two producers in the 7-spot pattern. The area sweep of the horizontal wells is, of course, uniform for a two-dimensional simulation. The combination well pattern shows a somewhat intermediate area sweep. Steam front advance is very like plug flow in blocks directly between the vertical injector and the horizontal producers. It also shows a region of unswept oil in the corner opposite the vertical injector.

We claim:

1. In a method for the enhanced recovery of a viscous oil from a subterranean, oil-bearing formation by injecting steam into the formation through at least one injection well and producing oil from a plurality of separate producing wells situated at an offset from the injection well, the improvement which comprises

(a) a plurality of substantially parallel horizontal production wells, and

(b) a plurality of vertical injection wells located between each pair of adjacent parallel horizontal production wells and spaced apart along the center line between each of said pairs of parallel horizontal production wells at distances equal to the separation of said parallel horizontal production wells.

2. A method according to claim 1 in which the number of said plurality of vertical injection wells situated between each pair of adjacent parallel horizontal production wells is equal to the quotient of the length of said parallel wells and the separation between said production wells.

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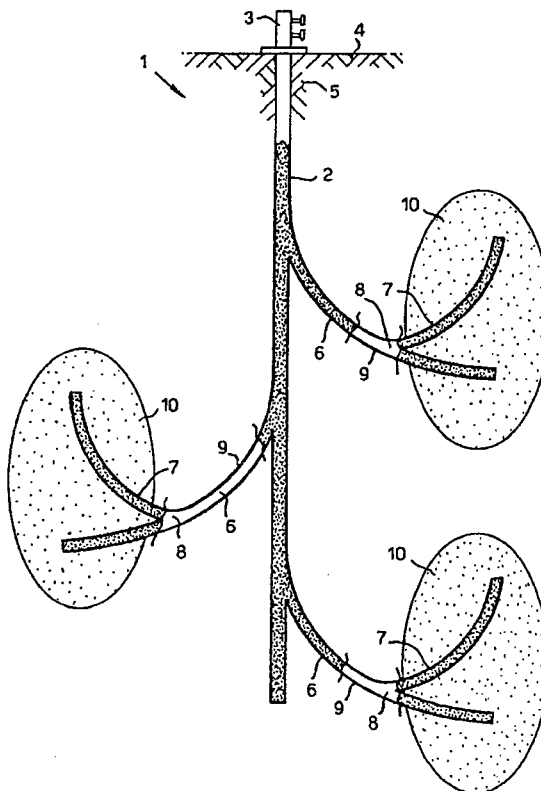
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(54) Title: METHOD FOR CREATING SECONDARY SIDETRACKS IN A WELL SYSTEM

(57) Abstract

A method is disclosed for creating one or more secondary sidetracks in an oil and/or gas well assembly which comprises a primary wellbore (2) and one or more primary sidetracks (6) so that a root-like multilateral well structure is created. The method makes use of an expandable well liner (9) in the primary sidetracks (6) so as to create a liner having a sufficient internal width to allow sidetracking equipment to be inserted and operated in the primary sidetrack to drill and complete the secondary sidetracks (7).



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METHOD FOR CREATING SECONDARY SIDETRACKS IN A WELL SYSTEM

Background of the Invention

The invention relates to a method for creating secondary sidetracks in a well system which comprises a main wellbore into which one or more primary sidetracks debouch.

Such a well system is known from International patent application WO 98/49424.

A difficulty which arises with such a well system is that conventional wells have a telescoping nature which stems from the fact that a casing is inserted into the main well at various stages of the drilling process and casing sections which are inserted thereafter need to have a smaller outer diameter than the inner diameter of the previously installed casing sections, and that the liner which is subsequently inserted into the primary sidetrack needs to have an outer diameter which is significantly smaller than the inner diameter of the casing of the main wellbore at the branchpoint in order to allow a smooth insertion of the liner from the main wellbore into the primary sidetrack.

As a result the liner of the primary sidetrack has such a small diameter that it is hardly feasible and economically unattractive to drill secondary sidetracks away from the primary sidetrack.

An object of the present invention is to provide a method for creating one or more secondary sidetracks in a well system in an efficient and economical manner.

Summary of the Invention

In accordance with the present invention a method is provided for creating a secondary sidetrack in a well system for production of hydrocarbon fluids which

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comprises a main wellbore and a primary sidetrack which debouches into the primary wellbore, the method comprising:

- 5 - inserting an unexpanded expandable liner into the primary sidetrack;
- radially expanding the liner;
- creating an opening in the wall of the expanded liner; and
- 10 - drilling a secondary sidetrack into the hydrocarbon formation through said opening.

Preferably the expandable liner is a steel liner which is expanded by pushing or pulling an expansion mandrel which is provided with a conical wear-resistant outer surface and/or rollers through the liner.

15 The expanded liner has an internal diameter which is sufficiently large to allow drilling and/or kick off equipment to be inserted into the primary sidetrack for drilling of one or more secondary sidetrack, which also have an internal width which is sufficiently large to
20 serve as a wellbranch through which hydrocarbon fluids can flow into the well system.

Hence the method according to the invention allows to create a root-like well system which provides an optimal drainage of hydrocarbon fluids from a hydrocarbon bearing
25 formation, even if the formation has a low permeability.

In an attractive embodiment of the method according to the invention the expandable liner is formed by a coiled tubing through which drilling fluid is pumped towards a downhole drilling assembly which is used to
30 drill the primary sidetrack and which coiled tubing is radially expanded after the primary sidetrack has been drilled.

Also the secondary sidetrack may be drilled using a coiled tubing which is expanded to form an expanded liner
35 after completion of the drilling activities.

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Alternatively the secondary sidetrack may be lined using an expandable slotted liner of which the slots are staggered and open up into diamond shaped apertures upon expansion of the liner. Such an expandable slotted line
5 is known from US patent No. 5,366,012. Such a slotted liner may be surrounded in the inflow region of the secondary sidetrack by an expandable sandscreen, such as a sandscreen which is disclosed in International patent application PCT/EP96/04887.

10 In stable reservoir formations the secondary sidetrack may be an open uncased hole whereas if the reservoir formation is very unstable the secondary sidetrack may be lined with an initially unslotted expanded or unexpanded liner into which perforations are
15 shot using a perforation gun which is known per se.

The invention also relates to a root-like well system which has been created in accordance with the invention and which comprises a main wellbore into which one or
20 more primary sidetracks comprising an expanded expandable liner debouch and one or more secondary sidetracks which debouch into the primary sidetrack or sidetracks through one or more openings in the wall of the expanded liner or liners.

It will be understood that the use of expandable
25 tubulars in a multilateral well system makes it possible that the well tubulars in the primary or mother well and in the primary and secondary sidetracks or well branches have a substantially equal internal width, so that a monobore multilateral well is created. In such a monobore
30 well system it is possible to drill tertiary sidetracks away from the secondary sidetracks, which sidetracking process can be repeated again and again so that a truly root-like multilateral well system is created.

Brief Description of the drawings

Preferred embodiments of the method and system according to the present invention will be described with reference to the drawings, in which:

5 Fig. 1 is a schematic vertical sectional view of a well system according to the invention; and

Fig. 2 is a schematic vertical sectional view of a well system according to the invention, which comprises a primary sidetrack into which two secondary sidetracks debouch.

Detailed Description of preferred Embodiments

Referring now to Fig. 1 there is shown a well system 1 according to the present invention which comprises a vertical main wellbore 2 which extends from a wellhead 3 at or near the earth surface 4 into a subsurface formation 5. Three primary sidetracks 6 debouch into the main wellbore 2. A secondary sidetrack 7 debouches into each primary sidetrack 6 through an opening 8 in the wall of an expanded expandable steel liner 9, of which only the section in the region of each opening 8 is shown.

20 The use of expanded liners 9 maximizes the internal width of the liners 9. Thus, if the wellbore of each sidetrack has a width of about 10 cm, the expanded liner may have an internal width of about seven to eight centimetres.

25 Such an internal width is a minimal requirement to allow a drilling assembly to be inserted into the primary sidetracks 6 which can be used to drill secondary sidetracks 7 of a sufficient width which is necessary to allow hydrocarbon fluids to flow in sufficient quantities through the secondary sidetracks 7 into the primary sidetracks.

30 Preferably also the main wellbore 2 is cased with an expandable steel casing which is cladded against the wellbore during the expansion process in a similar manner

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as the expandable liners 9 have been cladded against the wellbore of the primary sidetracks 6.

This allows a further increase in the internal width of the liners 9 and of the secondary sidetracks 7.

5 The primary and secondary sidetracks 6 and 7 each extend into hydrocarbon fluid bearing formations 10 which are shown as shaded areas in the drawing.

10 It will be understood that the illustrated well system provides a root-like well configuration which provides an optimum drainage of hydrocarbon fluids from the hydrocarbon fluid bearing formations 10.

Referring now to Fig. 2 there is shown a vertical primary wellbore 20 from which a primary sidetrack 21 has been drilled away in a horizontal direction.

15 The primary sidetrack 21 is lined with an expandable steel liner 22. Preferably the liner 22 is formed by a coiled tubing which has been used during drilling to feed drilling fluid to a drill bit (not shown) and to a hydraulic downhole mud motor (not shown) which is used to rotate the drill bit.

20 After completion of drilling the coiled tubing is expanded such that it is cladded against the wellbore and subsequently serves as a steel lining of the wellbore of the primary sidetrack 21.

25 Subsequently a 4.5 inch (= about 12 cm) shoe 22 and a plug 23 are installed near the toe 24 of the primary sidetrack 21 inside the liner 22.

30 Then a whipstock 25 is inserted and anchored within the liner 22 and a hanger 26 having an internal width of about 7 cm is inserted into the expanded liner 22 which has an internal width of about 10 cm. Then a drilling assembly (not shown) is inserted through the hanger 26 and is induced by the whipstock 25 to mill an opening into the liner 22 and to subsequently drill the secondary

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sidetrack 30 into a hydrocarbon fluid bearing formation 31.

5 In the example shown a conventional steel liner 31 has been inserted into the secondary sidetrack 30 which has an outer diameter of about 7 cm and which is perforated in the well inflow zone by means of a perforating gun (not shown).

10 After completion of the first secondary sidetrack 30 another whipstock 32 is inserted and anchored inside the expanded liner 22 close to the heel of the lateral primary sidetrack 21 whereupon yet another secondary sidetrack 33 is drilled and completed in the same manner as described with reference to the first secondary sidetrack 30.

15 After insertion of a steel liner 34 in the second secondary sidetrack either an opening (not shown) is drilled through the wall of the liner 34 and through the whipstock 34 or an already existing fluid passage in the whipstock and a fluid passage in the hanger 35 are used
20 to allow hydrocarbon fluid to flow from the first secondary sidetrack 30 and through the primary sidetrack 21 into the main wellbore 20.

C L A I M S

1. A method for creating a secondary sidetrack in a well system for production of hydrocarbon fluids from a hydrocarbon formation, which well system comprises a main wellbore and a primary sidetrack which debouches into the primary wellbore, the method comprising inserting an
5 unexpanded expandable liner into the primary sidetrack and radially expanding the liner; characterized in that an opening is created in the wall of the expanded liner in the primary sidetrack; and that a secondary sidetrack
10 is drilled into the hydrocarbon bearing formation through said opening.
2. The method according to claim 1, wherein the expandable liner is formed by a coiled tubing through which drilling fluid is pumped towards a downhole
15 drilling assembly which is used to drill the primary sidetrack and which coiled tubing is radially expanded after the primary sidetrack has been drilled.
3. The method according to claim 1 or 2, wherein the secondary sidetrack is drilled with a drilling assembly
20 which is connected to a coiled tubing, which tubing is expanded after the secondary sidetrack has been drilled to form a lining in the secondary sidetrack.
4. The method according to claim 1 or 2, wherein the secondary sidetrack is lined along at least part of its
25 length with an expandable slotted liner which is expanded inside the secondary sidetrack such that a series of staggered slots in the liner open up into diamond shaped apertures.
5. The method according to claim 4, wherein an
30 expandable sandscreen is arranged around the expandable

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slotted liner in the zone where hydrocarbon fluids flow into the well system.

5 6. The method according to claim 1, wherein an unexpandable liner is inserted into the secondary sidetrack which liner is perforated in the zone where hydrocarbon fluids flow into the well system.

7. The method according to claim 1, wherein the capillary sidetrack is uncased along at least part of its length.

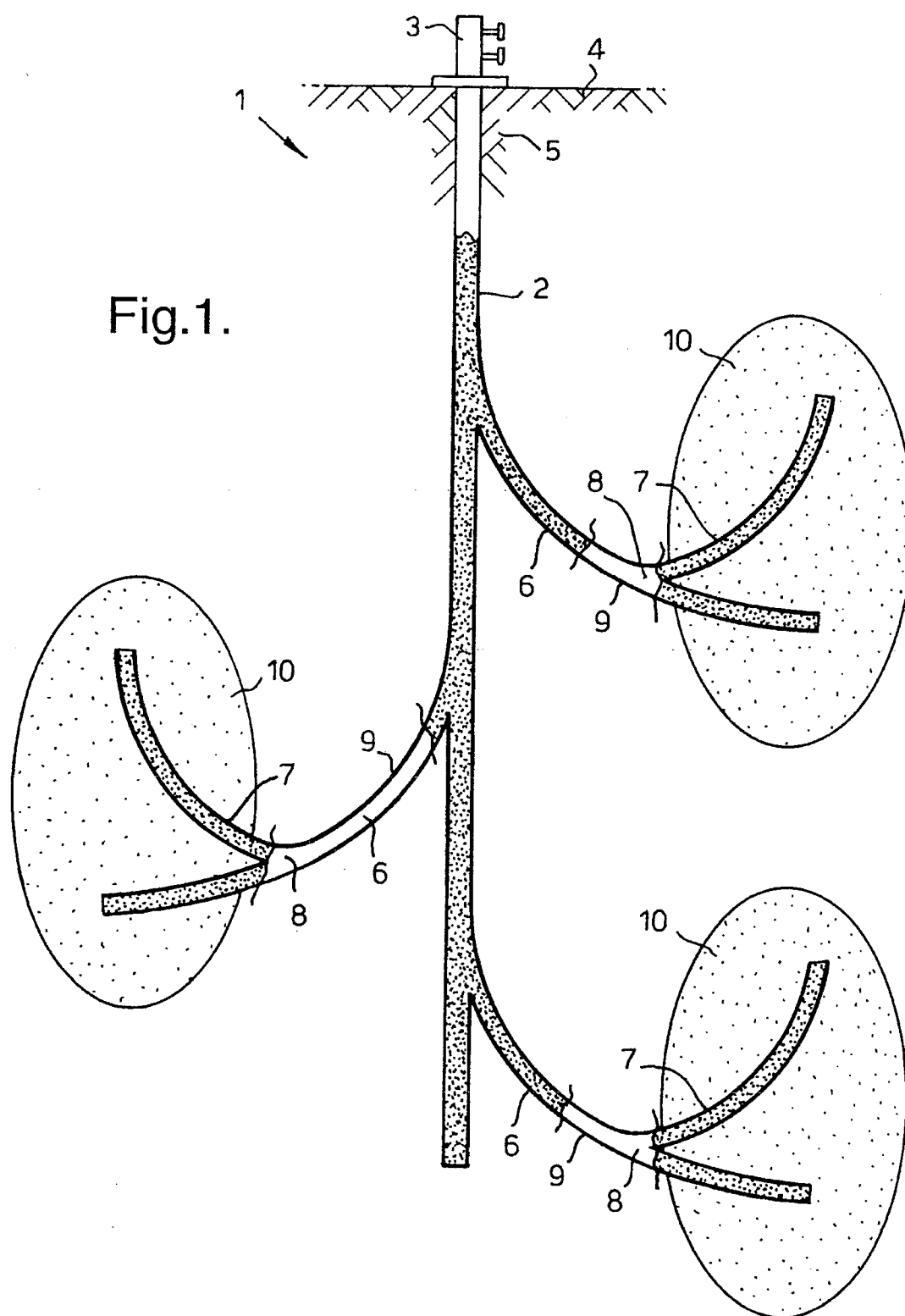
10 8. The method according to claim 1, wherein a plurality of primary sidetracks debouch into the primary wellbore and wherein a plurality of secondary sidetracks debouch into at least one of the primary sidetracks.

15 9. A well system comprising at least one primary sidetrack and at least one secondary sidetrack wherein the primary sidetrack comprises an expanded expandable liner which comprises an opening into which a secondary sidetrack debouches.

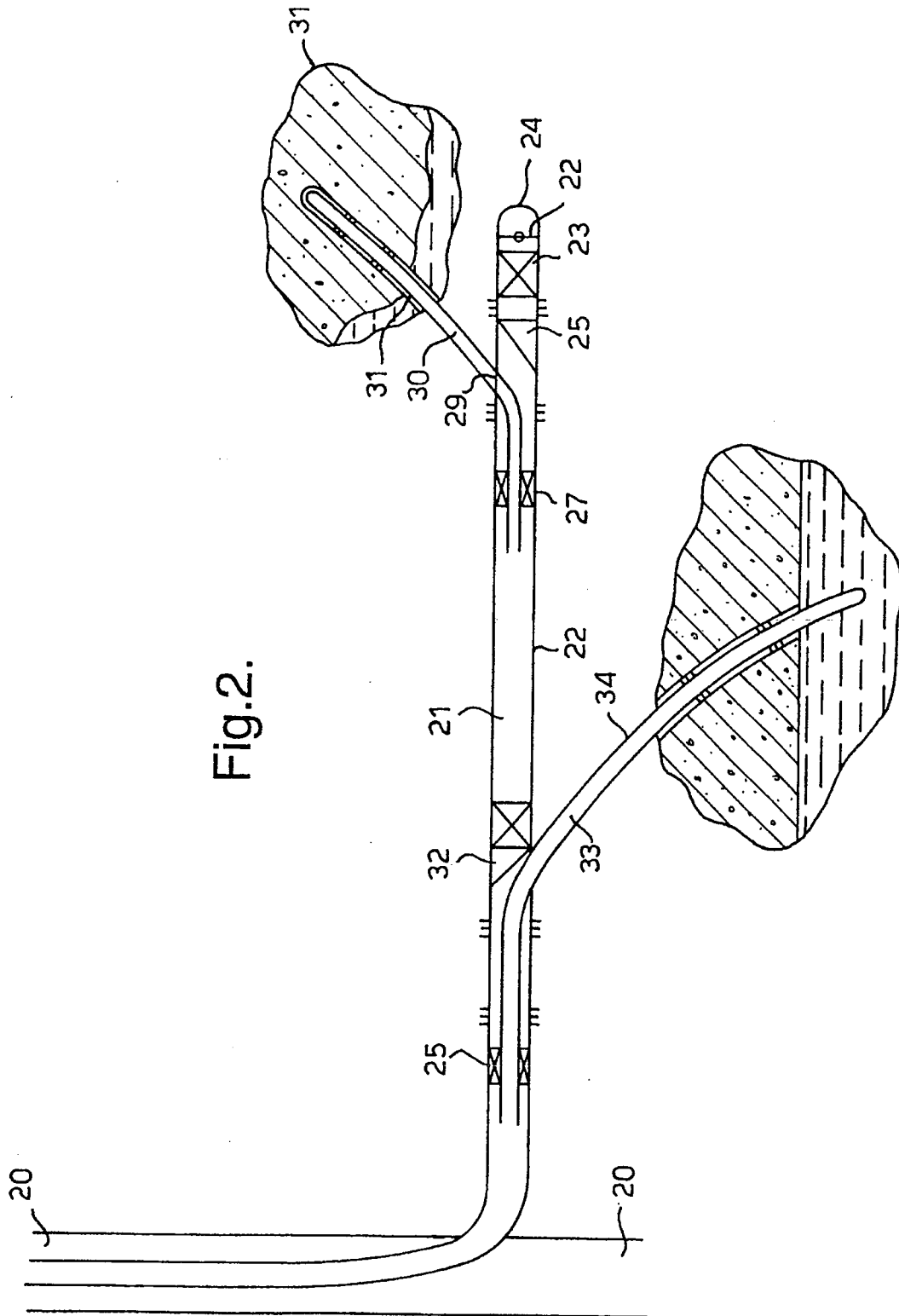
20 10. The well system of claim 9, wherein the expanded liner in the primary sidetrack has an internal width which is substantially equal to the internal width of a casing in the primary wellbore.

25 11. The well system of claim 10, wherein one or more tertiary sidetracks debouch into at least one secondary sidetrack so that a root-like multilateral well system is created.

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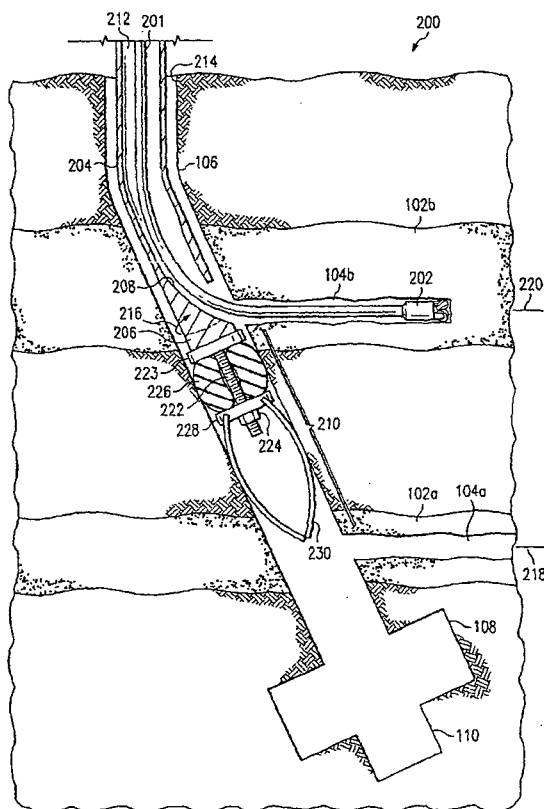
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[Continued on next page]

(54) Title: WELLBORE SEALING SYSTEM AND METHOD



(57) Abstract: In accordance with one embodiment of the present invention, a method for drilling wellbores includes drilling a main wellbore and disposing a casing string in the main wellbore. The casing string has a deflecting member and a sealing member coupled thereto. The method further includes disposing a drill string having a drill bit coupled at a lower end thereof in the casing string and drilling, from the main wellbore, a first lateral wellbore at a first depth with the drill bit. The method further includes removing the drill bit from the first lateral wellbore, transferring the casing string and the drill bit to a second depth that is higher than the first depth, drilling, from the main wellbore, a second lateral wellbore at the second depth with the drill bit, and preventing, using the sealing member, a fluid from the first lateral wellbore from flowing above approximately the second depth while drilling the second lateral wellbore.

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- as to the applicant's entitlement to claim the priority of the earlier application (Rule 4.17(iii)) for all designations

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WELLBORE SEALING SYSTEM AND METHOD

TECHNICAL FIELD OF THE INVENTION

The present invention relates generally to systems and methods for the recovery of subterranean resources and, more particularly, to a wellbore sealing system and method.

BACKGROUND OF THE INVENTION

Subterranean deposits of coal (typically referred to as "coal seams") often contain substantial quantities of entrained methane gas. Limited production and use of methane gas from coal seams has occurred for many years because substantial obstacles have frustrated extensive development and use of methane gas deposits in coal seams.

In recent years, various methods have been used to retrieve methane gas deposits from coal seams. One such method is the use of underbalanced drilling using a dual-string technique. As an example of this method, a fluid such as drilling fluid is circulated down a drill string, while another relatively light fluid such as air or nitrogen is circulated down an annulus formed between an outside surface of a drill string and an inside surface of a casing string. A mixture of these fluids is retrieved from an annulus formed between an outer surface of the casing string and an inside surface of the wellbore after mixing with a gas or other fluid obtained from a lateral wellbore being drilled. The purpose of the lighter fluid is to lighten the weight of the drilling fluid such that the hydrostatic head of the

drilling fluid does not force the drilling fluid into the subterranean formation and create detrimental effects.

SUMMARY OF THE INVENTION

5 The present invention provides a wellbore sealing system and method that substantially eliminates or reduces the disadvantages and problems associated with previous systems and methods.

10 In accordance with one embodiment of the present invention, a method for drilling wellbores includes drilling a main wellbore and disposing a casing string in the main wellbore. The casing string has a deflecting member and a sealing member coupled thereto. The method further includes disposing a drill string having a drill
15 bit coupled at a lower end thereof in the casing string and drilling, from the main wellbore, a first lateral wellbore at a first depth with the drill bit. The method further includes removing the drill bit from the first lateral wellbore, transferring the casing string and the
20 drill bit to a second depth that is higher than the first depth, drilling, from the main wellbore, a second lateral wellbore at the second depth with the drill bit, and preventing, using the sealing member, a fluid from the first lateral wellbore from flowing above approximately
25 the second depth while drilling the second lateral wellbore.

30 According to another embodiment of the present invention, a system for drilling wellbores includes a casing string, a deflecting member coupled to the casing string, and a sealing member coupled to the deflecting member. The sealing member is adapted to seal a wellbore into which the casing string is inserted such that a

fluid existing in the wellbore below the sealing member is prevented from flowing upward past the sealing member.

Some embodiments of the present invention may provide one or more technical advantages. These technical advantages may include more efficient drilling and production of methane gas and greater reduction in costs and problems associated with other drilling systems and methods. For example, there may be less damage to lateral wellbores because of mud or other fluids entering a lateral wellbore from the drilling of another lateral wellbore. In addition, cuttings are prevented from dropping into lower lateral wellbores while an upper lateral wellbore is being drilled. Another technical advantage includes providing a method for killing a lateral wellbore, while still being able to drill another lateral wellbore. An additional technical advantage is that underbalanced drilling may be performed along with the teachings of one embodiment of the present invention.

Other technical advantages of the present invention are readily apparent to one skilled in the art from the figures, descriptions, and claims included herein.

BRIEF DESCRIPTION OF THE DRAWINGS

For a more complete understanding of the present invention and its advantages, reference is now made to the following description taken in conjunction with the accompanying drawings, wherein like numerals represent like parts, in which:

FIGURE 1 is a cross-sectional view illustrating an example slant well system for production of resources

from one or more subterranean zones via one or more lateral wellbores;

FIGURE 2 illustrates an example system for drilling lateral wellbores according to one embodiment of the present invention;

FIGURE 3 illustrates an example system for drilling lateral wellbores according to another embodiment of the present invention; and

FIGURE 4 is a flowchart demonstrating an example method for drilling lateral wellbores according to one embodiment of the present invention.

DETAILED DESCRIPTION OF THE INVENTION

Embodiments of the present invention and their advantages are best understood by referring now to FIGURES 1 through 4 of the drawings, in which like numerals refer to like parts.

FIGURE 1 is a cross-sectional view illustrating an example well system 100 for production of resources from one or more subterranean zones 102 via one or more lateral wellbores 104. In various embodiments described herein, subterranean zone 102 is a coal seam; however, other subterranean formations may be similarly accessed using well system 100 of the present invention to remove and/or produce water, gas, or other fluids. System 100 may also be used for other suitable operations, such as to treat minerals in subterranean zone 102 prior to mining operations, or to inject or introduce fluids, gasses, or other substances into subterranean zone 102.

Referring to FIGURE 1, well system 100 includes an entry wellbore 105, two main wellbores 106, a plurality of lateral wellbores 104, a cavity 108 associated with

each main wellbore 106, and a rat hole 110 associated with each main wellbore 106. Entry wellbore 105 extends from a surface 12 towards subterranean zones 102. Entry wellbore 105 is illustrated in FIGURE 1 as being substantially vertical; however, entry wellbore 105 may be formed at any suitable angle relative to surface 12 to accommodate, for example, surface 12 geometries and/or subterranean zone 102 geometries.

Main wellbores 106 extend from the terminus of entry wellbore 105 toward subterranean zones 102, although main wellbores may alternatively extend from any other suitable portion of entry wellbore 105. Where there are multiple subterranean zones 102 at varying depths, as illustrated in FIGURE 1, main wellbores 106 extend through the subterranean zones 102 closest to surface 12 into and through the deepest subterranean zones 102. There may be one or any number of main wellbores 106. As illustrated, main wellbores 106 are slant wells and, as such, are formed to angle away from entry wellbore 105 at an angle designated α , which may be any suitable angle to accommodate surface topologies and other factors similar to those affecting entry wellbore 105. Main wellbores 106 are formed in relation to each other at an angular separation of β degrees, which may be any suitable angle, such as 60 degrees. However, main wellbores 106 may be separated by other angles depending likewise on the topology and geography of the area and location of a targeted subterranean zone 102. Main wellbores 106 may also include cavity 108 and/or rat hole 110 located at a terminus of each wellbore 106. Main wellbore 106 may

include one, both, or neither cavity 108 and rat hole 110.

Lateral wellbores 104 extend from each main wellbore 106 into an associated subterranean zone 102. Lateral wellbores 104 are shown in FIGURE 1 to be substantially horizontal; however, lateral wellbores 104 may be formed in other suitable directions off of main wellbores 106 and may have a curvature associated therewith. Any suitable systems and/or methods may be used to drill lateral wellbores 104; however, a particular system for drilling lateral wellbores 104 according to one embodiment of the present invention is described below in conjunction with FIGURES 2 through 4.

FIGURE 2 illustrates an example system 200 for drilling lateral wellbores 104 according to one embodiment of the present invention. As illustrated, system 200 includes a drill string 201 having a drill bit 202, a casing string 204, a deflecting member 206 having a deflecting surface 208 coupled to a lower end of casing string 204, and a sealing member 210 coupled to a lower end of deflecting member 206.

Drill string 201 may be any suitable drill string having any suitable length and diameter and any suitable drill bit 202 for the purpose of drilling lateral wellbores 104. Drill string 201 is typically a hollow conduit for allowing drilling fluids to flow therethrough. Drill bit 202 may be driven through the use of any suitable motor powered by the drilling fluid and may have any suitable configuration. To direct drill string 201 and drill bit 202 for the purpose of drilling lateral wellbore 104, deflecting surface 208 of deflecting member 206 is utilized.

Casing string 204 may be any suitable casing string having any suitable diameter that is to be inserted into main wellbore 106. Casing string 204 is adapted to rotate within main wellbore 106 as illustrated by arrow 216. An inner annulus 212 is formed between the inner surface of casing string 204 and the outer surface of drill string 201. An outer annulus 214 is also formed between an outside surface of casing string 204 and the surface of main wellbore 106. Inner annulus 212, outer annulus 214, and drill string 201 may be used to perform underbalanced drilling. As one example of underbalanced drilling, a first fluid may be circulated down drill string 201, such as drilling mud or other suitable drilling fluids. A second fluid is circulated down inner annulus 212, such as air, nitrogen, or other relatively light fluid. Both first and second fluids may be retrieved from outer annulus 214 after mixing with a gas or other fluid produced from lateral wellbore 104. The purpose of the second fluid is to lighten the weight of the first fluid such that the hydrostatic head of the first fluid does not force first fluid into the subterranean formation. As a variation, the second fluid may be circulated down outer annulus 214 and the mixture of the first and second fluids along with the gas from lateral wellbore 104 may be retrieved via inner annulus 212.

According to the teachings of the present invention, sealing member 210 is adapted to seal main wellbore 106 such that a fluid existing in main wellbore 106 below sealing member 210 is prevented from flowing upward past sealing member 210. In one embodiment of the invention, this allows the drilling of a lateral wellbore 104a in a

subterranean zone 102a at a first depth 218 and then the drilling of a lateral wellbore 104b in a subterranean zone 102b at a second depth 220, while ensuring that any gas or other fluid obtained from lateral wellbore 104a at first depth 218 does not flow past sealing member 210 and interfere with the drilling of lateral wellbore 104b in subterranean zone 102b at second depth 220. In addition, any cuttings resulting from the drilling of lateral wellbore 104b are prevented from dropping into lateral wellbore 104a. An example sealing member 210 is illustrated in FIGURE 2.

As illustrated in FIGURE 2, example sealing member 210 includes a bolt 222, a nut 224, a plug 226, a washer 228, and a resilient member 230. Bolt 222 is coupled to a lower end 223 of deflecting member 206 in any suitable manner. Nut 224 is threaded on bolt 222, while washer 228 surrounds bolt 222 and is rigidly coupled to nut 224. Plug 226 surrounds bolt 222 and is disposed between washer 228 and lower end 223 of deflecting member 206.

Plug 226 is formed from any suitable material, such as an elastomer, resilient enough to be circumferentially expanded or circumferentially retracted but stiff enough to be able to prevent any gas or other fluid existing in main wellbore 106 below sealing member 210 to leak past plug 226. The circumferential expansion or retraction of plug 226 via the rotation of casing string 204 is described in more detail below. In other embodiments, plug 226 is an air-filled diaphragm formed from any suitable material.

Resilient member 230 is coupled to washer 228 in any suitable manner. Resilient member 230, which may be any suitable resilient member, such as a bow spring, is

adapted to engage the wall of main wellbore 106 and apply enough force to the wall of main wellbore 106 to prevent nut 224 and washer 228 from turning while casing string 204 is rotated within main wellbore 106. Washer 228 and nut 224 are fixed to one another such that, when casing string 204 is rotated, nut 224 and washer 228 do not rotate. In this way, bolt 222 may longitudinally compress plug 226 to circumferentially expand plug 226 so that it may press against the wall of main wellbore 106 to prevent gas or other fluid from flowing upward past plug 226. Conversely, when casing string 204 is rotated in an opposite direction, then bolt 222 acts to longitudinally decompress plug 226, thereby circumferentially retracting plug 226 so that gas or other fluid may bypass plug 226.

In operation of one embodiment of system 200 of FIGURE 2, main wellbore 106 is drilled via any suitable method. Casing string 204 having deflecting member 206 and sealing member 210 attached thereto is inserted into main wellbore 106. While lowering casing string 204 down main wellbore 106, plug 226 is in a circumferentially retracted position so that any air or other fluid existing at a depth below sealing member 210 may leak past plug 226. Once at a desired depth, such as first depth 218, drill string 201 is inserted within casing string 204 so that lateral wellbore 104a may be drilled at first depth 218. After drilling lateral wellbore 104a drill string 201 is retracted from lateral wellbore 104a. At this time, casing string 204 is rotated in a desired direction so that plug 226 may be longitudinally compressed and circumferentially expanded to press against the wall of main wellbore 106. As described

above, this prevents any gas or other fluid produced from lateral wellbore 104a from traveling up past plug 226. Casing string 204 may then be raised to second depth 220 so that lateral wellbore 104b may be drilled. Lateral wellbore 104b may then be drilled with drill bit 202 with the assurance that sealing member 210 will prevent any gas or fluid from passing upward and causing detrimental effects. Other lateral wellbores 104 may be drilled successively at shallower depths according to a similar procedure. Many different types of sealing members 210 are contemplated by the present invention. Another example sealing member is shown below in conjunction with FIGURE 3.

FIGURE 3 illustrates another example sealing member 310. In one embodiment, sealing member 310 is a resilient plunger 300 formed from a suitable elastomer; however, other suitable resilient materials may be utilized. As illustrated, plunger 300 includes a plurality of ridges 302 that have an inherent stiffness to prevent gas or other fluid from a depth in main wellbore 106 below plunger 300 from leaking past plunger 300 to a higher depth (or vice versa) while a lateral wellbore 104 is being drilled. In addition, plunger 300, via ridges 302, possesses enough resiliency to allow gas or other fluid existing at a depth below plunger 300 to flow past plunger 300 to relieve any potential increasing pressure below plunger 300 when plunger 300 is inserted into main wellbore 106. Plunger 300 may have other suitable configurations and may be coupled to deflecting member 206 in any suitable manner. In other embodiments, plunger 300 is a hollow plunger having any suitable fluid therein.

Plunger 300 may also include a relief valve (not shown) that is operable to allow gas or other fluid at a depth below plunger 300 to flow to a depth above plunger 300 when a predetermined pressure is reached. Any
5 suitable relief valve may be utilized and the relief valve may be coupled to plunger 300 in any suitable manner. The relief valve may be set to open or close at a predetermined pressure depending on the pressure expected to be encountered in main wellbore 106 below
10 sealing member 310. A relief valve may also be utilized with sealing member 210 of FIGURE 2 in a similar manner.

FIGURE 4 is a flow chart demonstrating an example method of drilling lateral wellbores 104 according to one embodiment of the present invention. The method begins
15 at step 400 where main wellbore 106 is drilled. Casing string 204 having deflecting member 206 at a lower end thereof is disposed in main wellbore 106 at step 402. Deflecting member 206 has any suitable sealing member coupled at a lower end thereof. Although example sealing
20 members 210 and 310 are described above, any suitable sealing member may be used within the scope of the present invention.

As described above, the sealing member prevents a gas or other fluid from a lower lateral wellbore from
25 flowing up to a higher lateral wellbore at a higher depth while drill string 201 is drilling the higher lateral wellbore. At step 404, drill string 201 having drill bit 202 is disposed in casing string 204. At step 406, a first lateral wellbore 104a is drilled from main wellbore
30 106 at first depth 218. Deflecting surface 208 of deflecting member 206 is utilized to direct drill string 201 in the desired drilling direction.

After first lateral wellbore 104a is drilled, drill bit 202 is removed from first lateral wellbore 104a at step 408. At step 410, casing string 204 and drill bit 202 are transferred to second depth 220 that is less than first depth 218. Any gas or other fluid produced from first lateral wellbore 104a is prevented, as denoted by step 412, from flowing up to second depth 220 by the sealing member. At step 414, second lateral wellbore 104b is drilled from main wellbore 106 at second depth 220 with drill bit 202. Successive lateral wellbores 104 may be drilled at successively higher depths per the above method. In lieu of a slant well system, the described example method may be used with other suitable well systems.

Although the present invention is described with several embodiments, various changes and modifications may be suggested to one skilled in the art. The present invention intends to encompass such changes and modifications as they fall within the scope of the appended claims.

WHAT IS CLAIMED IS:

1. A method for drilling wellbores, comprising:
drilling a main wellbore;

5 disposing a casing string in the main wellbore, the casing string having a deflecting member and a sealing member coupled thereto;

disposing a drill string having a drill bit coupled at a lower end thereof in the casing string;

10 drilling, from the main wellbore, a first lateral wellbore at a first depth with the drill bit;

removing the drill bit from the first lateral wellbore;

transferring the casing string and the drill bit to a second depth that is higher than the first depth;

15 drilling, from the main wellbore, a second lateral wellbore at the second depth with the drill bit; and

preventing, using the sealing member, a fluid from the first lateral wellbore from flowing above approximately the second depth while drilling the second lateral wellbore.

20

2. The method of Claim 1, further comprising:

removing the drill bit from the second lateral wellbore;

25 transferring the casing string and the drill bit to a third depth that is higher than the second depth;

drilling, from the main wellbore, a third lateral wellbore at the third depth with the drill bit; and

30 preventing, using the sealing member, the gas from flowing above approximately the third depth while drilling the third lateral wellbore.

3. The method of Claim 1, wherein drilling the main wellbore comprises drilling a slant wellbore.

5 4. The method of Claim 1, further comprising disposing the casing string in the main wellbore such that an outer annulus is formed between a wall of the main wellbore and an outer wall of the casing string, and disposing the drill string in the casing string such that an inner annulus is formed between an inner wall of the casing string and an outer wall of the drill string.

10 5. The method of Claim 4, further comprising:
circulating a first fluid down an inner passage of the drill string;

15 circulating a second fluid down the inner annulus;
regulating an amount of the second fluid to prevent the first fluid from entering a subterranean formation in which the lateral wellbore is being drilled; and

20 retrieving a mixture of the first and second fluids and the gas from the lateral wellbore through the outer annulus.

25 6. The method of Claim 4, further comprising:
circulating a first fluid down an inner passage of the drill string;

circulating a second fluid down the outer annulus;
regulating an amount of the second fluid to prevent the first fluid from entering a subterranean formation in which the lateral wellbore is being drilled; and

30 retrieving a mixture of the first and second fluids and the gas from the lateral wellbore through the inner annulus.

15

7. The method of Claim 1, wherein disposing the casing string in the main wellbore comprises lowering the casing string down the main wellbore while allowing a fluid in the main wellbore below the sealing member to flow past the sealing member.

8. The method of Claim 1, wherein preventing the gas from the first lateral wellbore from flowing above approximately the second depth while drilling the second lateral wellbore comprises longitudinally compressing a plug of the sealing member to circumferentially expand the plug such that an outer surface of the plug engages a wall of the main wellbore.

9. The method of Claim 8, further comprising rotating the casing string to longitudinally compress the plug.

10. The method of Claim 1, wherein preventing the gas from the first lateral wellbore from flowing above approximately the second depth while drilling the second lateral wellbore comprises utilizing a resilient plunger as the sealing member.

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11. A system for drilling wellbores, comprising:
a casing string;
a deflecting member coupled to the casing string;
and

5 a sealing member coupled to the deflecting member,
the sealing member configured to seal a wellbore into
which the casing string is inserted such that a fluid
existing in the wellbore below the sealing member is
prevented from flowing upward past the sealing member.

10 12. The system of Claim 11, wherein the sealing
member comprises a resilient plunger.

15 13. The system of Claim 12, wherein the sealing
member further comprises a relief valve operable to allow
a fluid in the wellbore below the resilient plunger to
flow past the resilient plunger.

20 14. The system of Claim 11, wherein the sealing
member comprises a solid plug.

15. The system of Claim 14, wherein the sealing
member further comprises:

25 a bolt to support the solid plug;
a nut coupled to the bolt;
a washer disposed between the nut and the plug; and
a spring member coupled to the washer, the spring
member adapted to engage a wall of the wellbore to
prevent the washer from rotating when the casing string
30 is rotated in the wellbore such that the solid plug is
longitudinally compressed and circumferentially expanded
to engage the wall of the wellbore.

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16. The system of Claim 11, wherein the sealing member comprises an air-filled diaphragm.

17. A sealing member, comprising:

a resilient plunger adapted to couple to an end of a casing string and operable to prevent a gas within a wellbore from flowing from a lower depth below the resilient plunger to a higher depth above the resilient plunger while a lateral wellbore is being drilled.

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18. A sealing member, comprising:

a bolt adapted to couple to an end of a casing string;

a nut rotatably coupled to the bolt;

5 a washer engaged with the nut;

a plug surrounding the bolt and resting against the washer;

a spring member coupled to the washer, the spring member adapted to engage a wall of a wellbore to prevent the washer from rotating when the casing string is rotated in the wellbore such that the plug is longitudinally compressed and circumferentially expanded to engage the wall of the wellbore to prevent a gas within the wellbore from flowing from a lower depth below the plug to a higher depth above the plug while a lateral wellbore is being drilled.

19. The sealing member of Claim 18, wherein the spring member is adapted to engage the wall of the wellbore to prevent the washer from rotating when the casing string is rotated in the wellbore such that the plug is longitudinally expanded and circumferentially retracted to allow a gas within the wellbore from flowing from a lower depth below the plug to a higher depth above the plug.

20. The sealing member of Claim 18, wherein the plug comprises an air-filled diaphragm.

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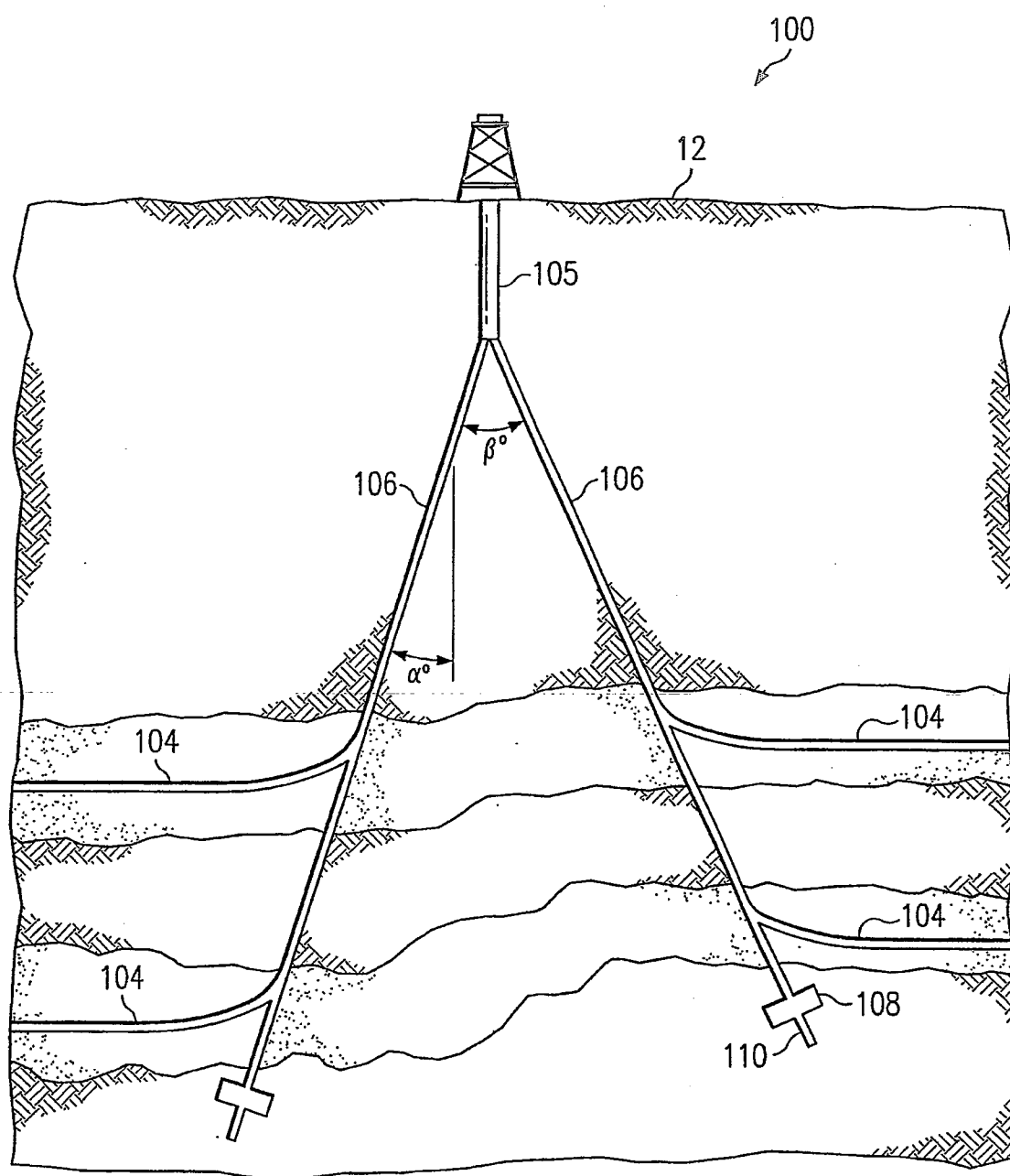


FIG. 1

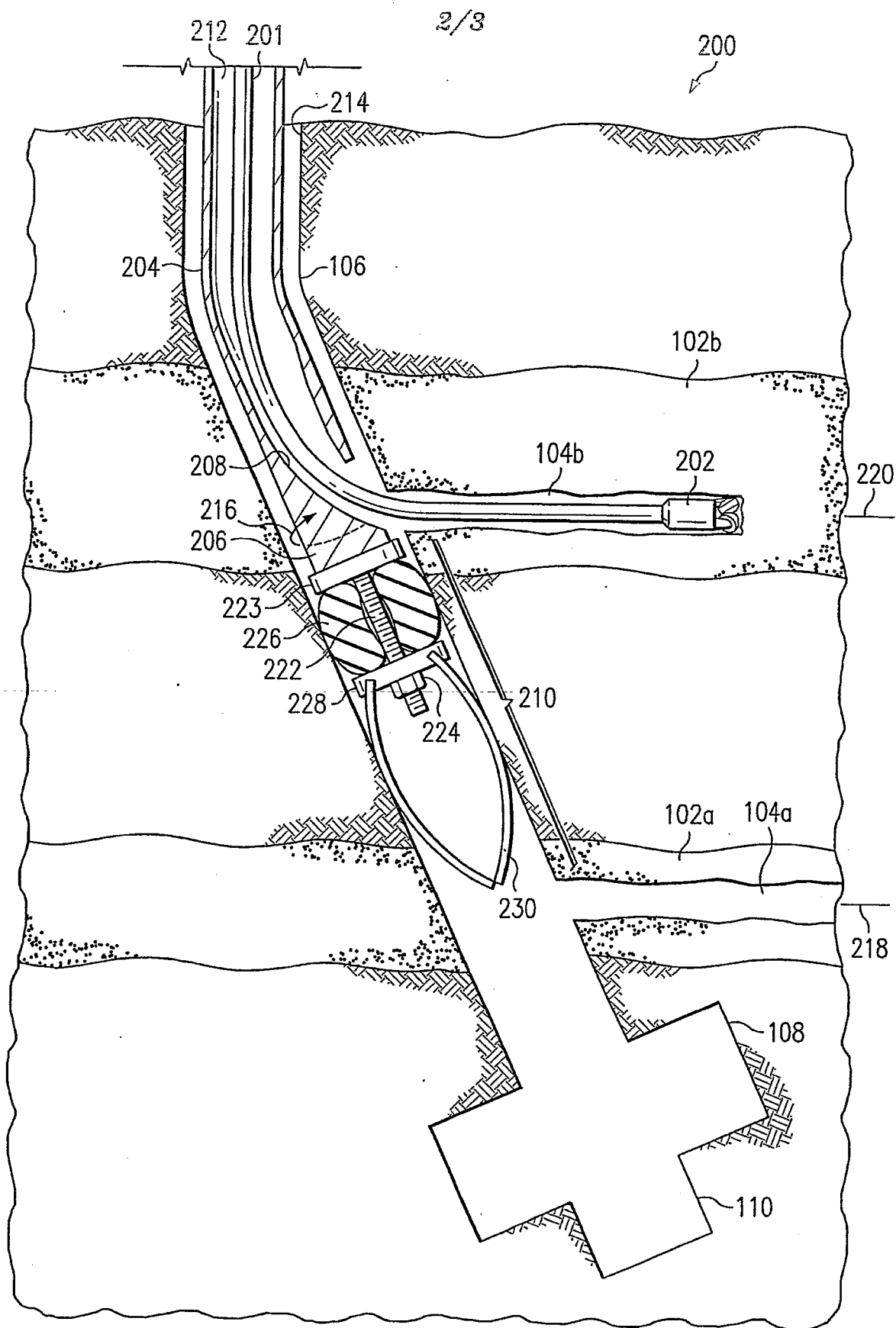
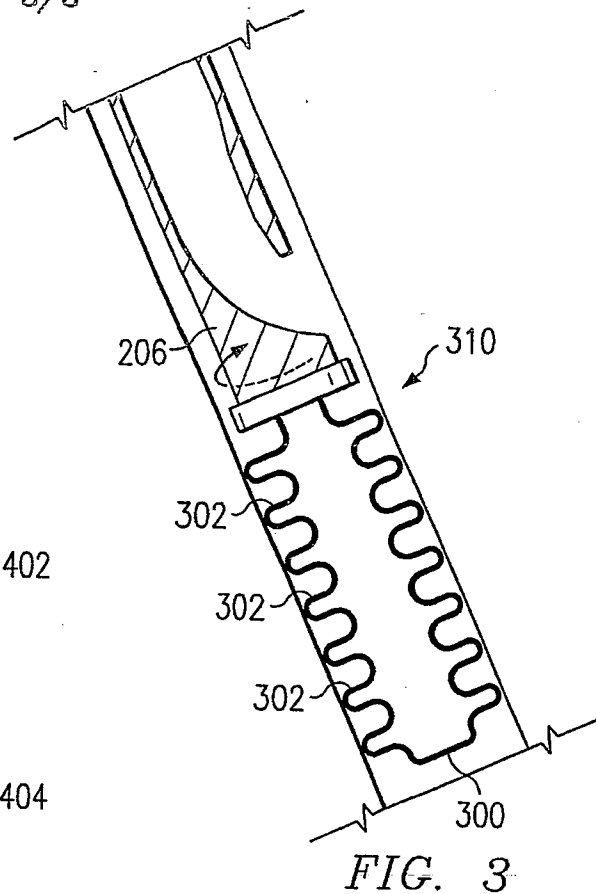
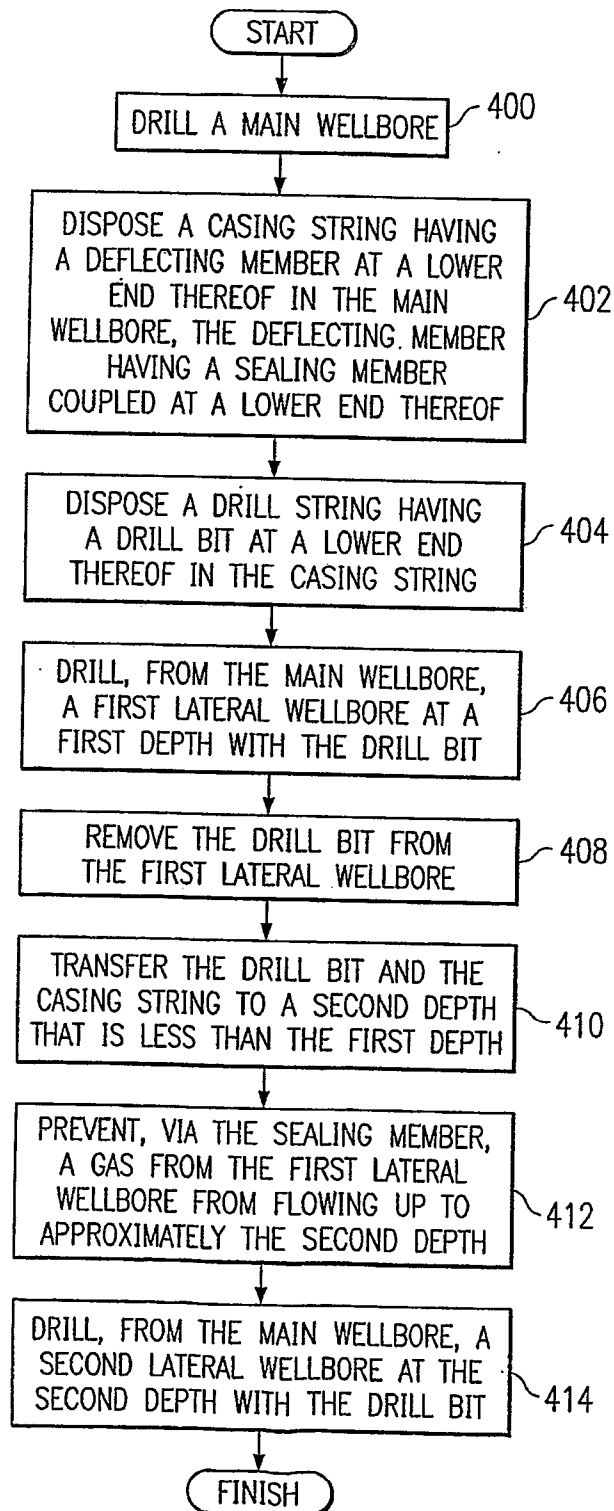


FIG. 2

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FIG. 4





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Den Boer et al.

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(54) **MULTILATERAL WELL AND ELECTRICAL TRANSMISSION SYSTEM**

(75) **Inventors:** **Johannis Josephus Den Boer; Simon Lawrence Fisher; Anthony Evert Kuperij; John Foreman Stewart**, all of Rijswijk (NL)

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(58) **Field of Search** **166/50, 65.1, 66.7, 166/207, 313, 334.4**

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Primary Examiner—David Bagnell

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(57) **ABSTRACT**

There is provided a multilateral well and electric transmission system comprising a branch well tubular in a branch wellbore which is connected in an electrically conductive manner to a primary well tubular in a primary wellbore such that the primary and branch well tubulars form a link for transmission of electrical power and/or signals between the primary and branch wellbores. Low voltage electrical power can be transmitted from the surface to a battery in the branch wellbore to trickle-charge the battery and signals from battery-actuated measuring and control equipment in the branch wellbore can be transmitted back to surface via the walls of the electrically interconnected primary and branch well tubulars.

9 Claims, 3 Drawing Sheets

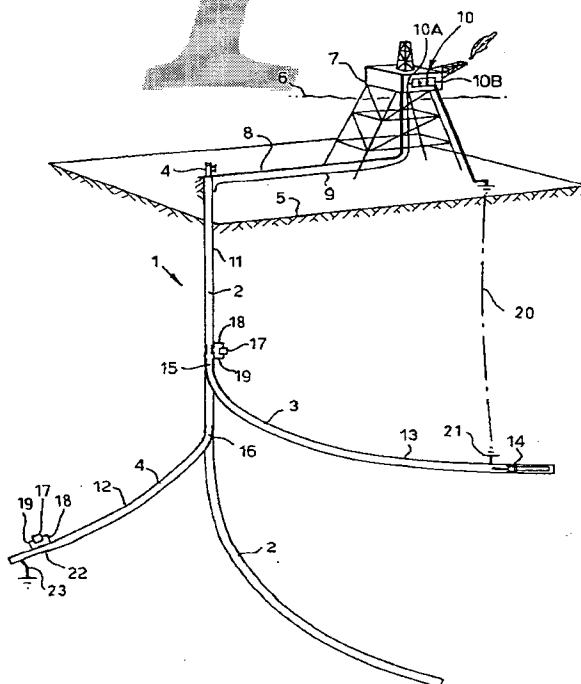


Fig.1.

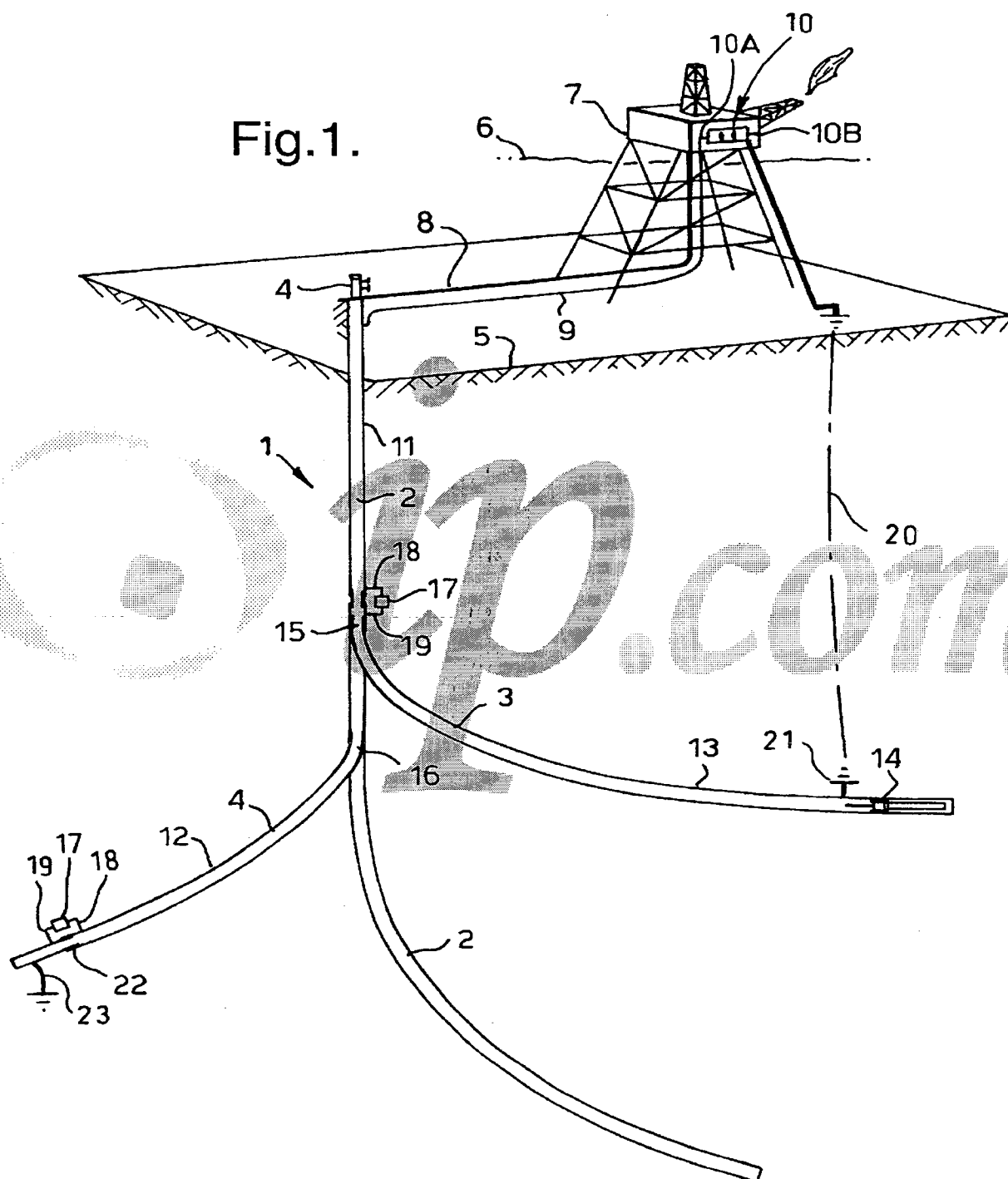


Fig.2.

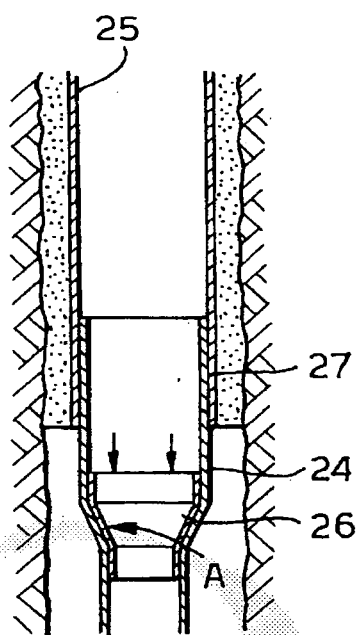


Fig.3.

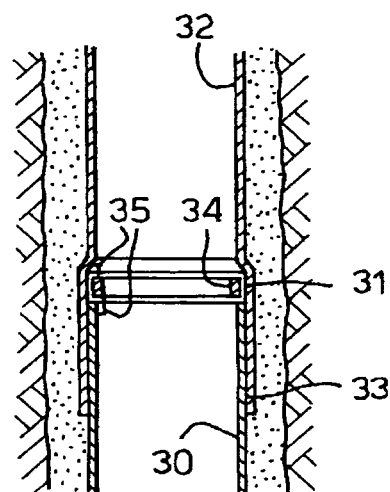


Fig.4.

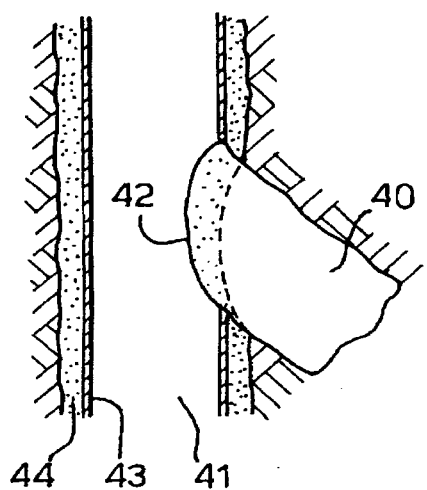
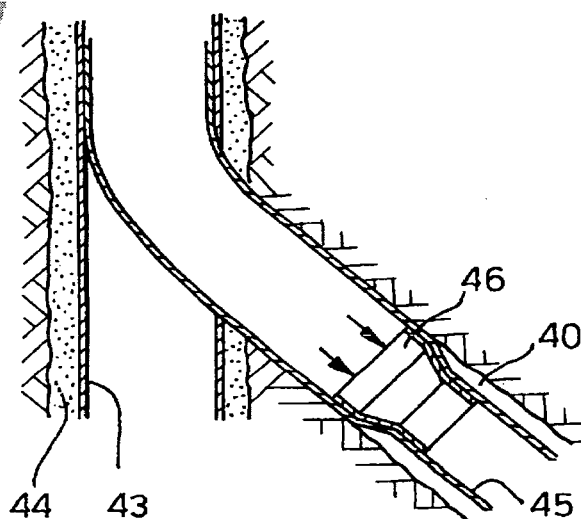
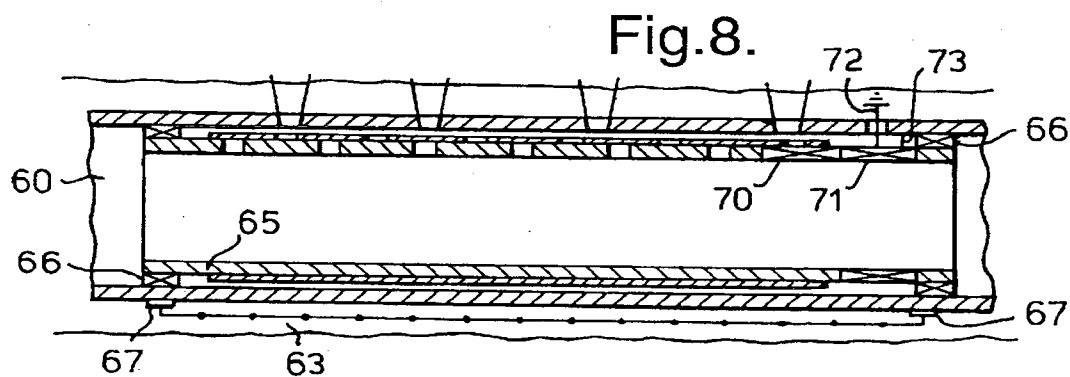
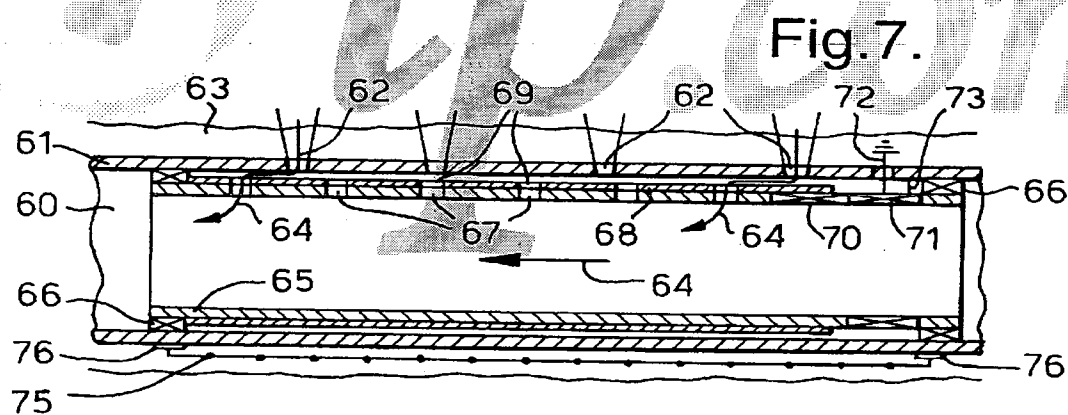
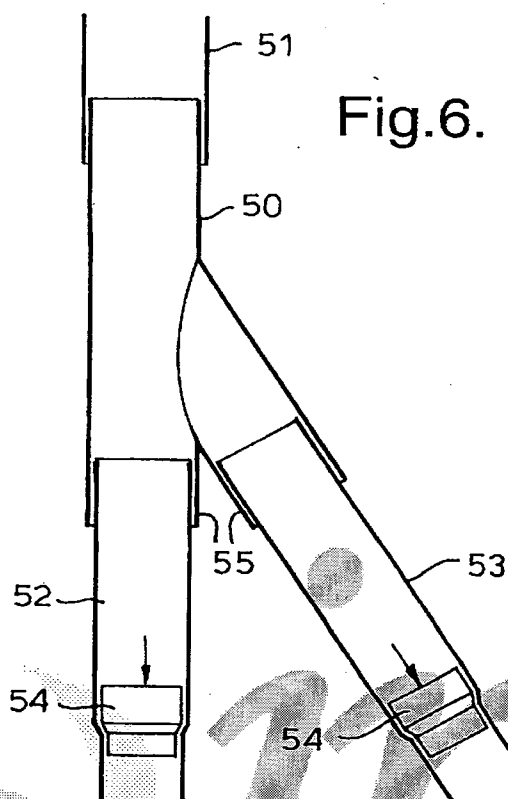


Fig.5.





MULTILATERAL WELL AND ELECTRICAL TRANSMISSION SYSTEM

FIELD OF THE INVENTION

The invention relates to a multilateral well and electrical transmission system.

BACKGROUND OF THE INVENTION

Numerous electrical and non-electrical power and communication systems are known for use in unbranched or multilateral oil and/or gas production wells.

U.S. Pat. Nos. 5,706,892; 5,706,896 and 5,721,538 disclose that a multilateral well may be equipped with a hardwired electrical or with a wireless communication system and that such a wireless system preferably transmits acoustic waves through a string of well tubulars such as the production tubing. Disadvantages of the known system are that installation of a wire tree in a multilateral well is a complex and expensive operation and that a wireless acoustic transmission system will suffer from high transmission losses and background noise. These disadvantages are particularly significant if the well is equipped with an expandable casing and/or production tubing. Around such an expanded well tubular there is hardly any or no annular space left for housing of the electrical cables and as a result of the physical contact between the expanded tubular and the surrounding formation acoustic signals will be dampened to a high extent.

Numerous other hardwired or wireless power transmission and communication systems are known, which have in common that they require complex and expensive equipment and that they are not suitable for use in multilateral wells.

U.S. Pat. No. 4,839,644 and European patent No. 295178 disclose a wireless communication system known as "Tuc-atran" which generates antenna currents in an unbranched well where the production tubing and surrounding well casing are electrically insulated from each other. The requirement of electrical insulation between the tubing and the casing is often difficult to accomplish in e.g. curved borehole sections and areas where brine is present in the tubing/casing annulus. International patent application WO80/00727 discloses another signal transmission system which utilizes an electrical circuit formed by a production tubing and a surrounding well casing.

U.S. Pat. No. 4,484,627, UK patent application No. 2322740 and International patent applications Nos. PCT/GB79/00158; PCT/GB93/01272 and PCT/EP96/00083 disclose other downhole electric transmission systems which utilize an externally insulated tubing in an unbranched well.

The present invention aims to overcome the disadvantages of the known transmission systems and to provide a downhole power and/or signal transmission system which can be used to transmit electrical power and/or signals throughout a multilateral well system in a safe and reliable manner even if the well comprises expandable well tubulars and without requiring complex wire trees or production tubing that are electrically insulated from the surrounding well casings.

SUMMARY OF THE INVENTION

In accordance with the invention there is provided a multilateral well and electric transmission system, which comprises a primary wellbore in which a primary well tubular is arranged and a branch wellbore in which a branch

well tubular is arranged, wherein the branch well tubular is connected in an electrically conductive manner to the primary well tubular such that the primary and branch well tubulars form a link for transmission of electrical power and/or signals between the primary and branch wellbore.

Preferably, the primary and branch well tubulars form a link for transmitting low voltage power from a first pole of an electrical power source, which is electrically connected to the primary well tubular, to electrically powered equipment within the branch wellbore which is electrically connected to the branch well tubular. An electrical circuit is created by electrically connecting a second pole of the electrical power source and the branch well tubular(s) to the earth. It is also preferred that said equipment comprises a re-chargeable battery which is trickle-charged by the low voltage electrical power transmitted via the well tubulars.

Suitably low voltage power is transmitted as a direct current (DC) having a voltage of less than 100 V, preferably less than 50 V through the casing or production tubing of the primary well, which is imperfectly insulated to the surrounding earth formation by a surrounding cement or other sealing material, such as an addition curing silicone composition.

At the same time pulsed electromagnetic signals are transmitted which involve changes of voltage level oscillating around the DC voltage level of the well tubular at very low frequency (VLF), between 3 and 20 kHz, or preferably at extremely low frequency (ELF), between 3 and 300 HZ.

The surface power generator and the downhole equipment or battery may have an electrode which is connected to the earth so that an imperfect electric loop exists between the power generator and the downhole equipment or battery.

It is also preferred that the branch well tubular is a radially expandable tubular which is made of an electrically conductive material and which is radially expanded within the branch well during installation and wherein an electrically conductive receptacle is arranged at or near the branchpoint such that the expanded branch well tubular is pressed into electrical contact with the receptacle as a result of the expansion process.

A particular advantage of the use of expandable tubulars at least in the branch wellbore is that as a result of the radial expansion process a surplus expansion is created in the expanded tubular which will ensure an intimate electrical contact between adjacent well tubulars of which the ends coaxially overlap each other. Such an intimate electrical contact is also made at the branchpoint between the expanded branch well tubular and the receptacle which may be formed by the primary well tubular itself or by a branched bifurcation element.

Suitably the primary and branch well tubulars are made of a formable steel grade and the branch well tubular is expanded during installation such that the expanded branch well tubular has an inner diameter which is at least 0.9 times the inner diameter of the primary well tubular, so that a substantially monobore multilateral well system is created which may have any desired amount of branches and sub-branches.

Preferably the electrically powered downhole well equipment comprises measuring and/or control equipment which is powered by a rechargeable lithium-ion high-temperature or other battery and/or a supercapacitor and/or a downhole energy conversion system such as a piezo-electrical system, turbine or downhole fuel cell and is mounted on an equipment carrier module in the form of a sleeve which is removably secured within the branch well tubular such that one electrode of the battery is electrically connected to the

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branch well tubular and another electrode of the battery is electrically connected to the subsurface earth formation surrounding the branch wellbore.

Suitably the sleeve spans an inflow area of the branch wellbore where the branch well tubular is perforated, the expandable clamps consist of a pair of expandable packers which seal off an annular space between the branch well tubular and sleeve near each end of the sleeve and wherein the sleeve is provided with one or more fluid inlet ports which can be opened and closed by one or more valves which are powered by the rechargeable battery. The triggering can be done via a downhole or surface actuated control system.

In many lengthy multilateral well systems it is also preferred that at least one of the primary and branch well tubulars is equipped with at least one electrical booster station which station spans an electrically non-conductive section of the well tubular and which station is electrically connected to the electrically conductive parts of the well tubular at both sides of the electrically non-conductive section thereof.

The electrical booster stations may be distributed at regular intervals along the length of the primary and branch wellbore. If an electrical booster station is required at a location where the ends of two adjacent expanded well tubulars co-axially overlap each other, an electrical sealing material may be arranged between the overlapping tubular sections and the booster may be installed as a sleeve within the outermost tubular adjacent to the innermost tubular such that one electrode of the booster station is electrically connected to the innermost and another electrode thereof is connected to the outermost tubular.

It is observed that in some instances the booster station may be installed at a well junction, in which case the electrodes of the booster station will make the electric connection between the primary and branch well tubulars.

It is also observed that when used in specification the and the appended claims the term multilateral well system refers to a well system having a primary or mother wellbore which extends from a wellhead down into a surface earth formation and at least one branch wellbore which intersects the primary or mother wellbore at a subsurface location.

BRIEF DESCRIPTION OF THE DRAWINGS

Preferred embodiments of the system according to the invention will be described with reference to the accompanying drawings, in which

FIG. 1 is a schematic three-dimensional view of a multilateral well system according to the invention;

FIG. 2 shows how a well tubular is expanded using a conical expansion mandrel;

FIG. 3 shows a connection between two well tubulars where an electrical booster station is arranged;

FIG. 4 shows a branchpoint where a branch wellbore has been drilled through a window in the primary well casing;

FIG. 5 shows how an expandable well liner is expanded in the branch wellbore and electrically connected to the primary well casing;

FIG. 6 shows a branchpoint where the branch well casing and the primary casing underneath the branchpoint are expanded within a bifurcation element or splitter;

FIG. 7 shows a tubular equipment carrier sleeve in the open mode such that oil and/or gas flows via perforations in the sleeve into the wellbore; and

FIG. 8 shows the sleeve of FIG. 7 in the closed mode in which the perforations have been closed off.

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DETAILED DESCRIPTION OF PREFERRED EMBODIMENTS

Referring to FIG. 1 there is shown a multilateral well and electric transmission system 1, which comprises a primary wellbore 2 and two branch wellbores 3 and 4.

The system 1 extends from an underwater wellhead 4 into the bottom 5 of a body of water 6. Oil and/or gas processing equipment on an offshore platform 7 is connected to the wellhead 47 via an underwater flowline 8 and a power supply cable 9 extends from a first pole 10A of an electrical power generator 10 at the platform 7 to primary well casing 11 which has been expanded against the wall of the primary wellbore 2 such that a thin annular layer (not shown) of cement or another sealing material such as an addition curing silicone formulation is present between the expanded casing 11 and borehole wall.

In the lower branch wellbore 4 a branch well liner 12 has been expanded and cemented in place, whereas in the upper branch wellbore 3 a branch well liner 13 is being expanded by pumping or pushing an expansion mandrel 14 there-through towards the toe of the well.

As a result of the expansion process a surplus expansion is created in the expanded casing or liner which ensures that the expanded branch well liners 12 and 13 are firmly pressed against the inner wall of the primary well casing 11 at the branchpoints 15 and 16 so that an excellent electrical connection is established between the branch well liners 12 and 13 and the primary well casing 11.

In the primary well casing 11 an electrical booster station 17 is arranged at a location where an electric insulation sleeve is mounted within the casing 11 and the casing has been milled away over a selected distance. The booster station 17 has one electrode 18 which is electrically connected to the casing section above the gap and another electrode 19 which is electrically connected below the gap. Likewise a similar booster station 17 is arranged in the lower branch wellbore 4 and has electrodes 18,19 which are connected to sections of the branch well liner 12 which co-axially overlap but which are electrically insulated from each other by an electric insulation sleeve 22. Instead of using co-axial electrically insulated tubular sections the electrical insulation may be achieved also by using a pre-installed plastic section in the well tubular which plastic section is expanded in the same way as the steel parts of the tubular string.

For the sake of clarity the power booster stations 17 are shown outside the wellbore but in general these stations 17 will be mounted in an annular carrier sleeve within the well tubulars as is illustrated in FIG. 3. FIG. 1 also shows schematically that a second pole 10B of the electrical power generator 10 is connected to earth and that also the branch well liners 12 and 13 are connected to earth at one or more selected locations 21 and 23 so that the earth 5 forms an electrical return link, illustrated by phantom line 20, from the well liners 12 and 13 and said second pole 10B.

FIG. 2 shows how a lower well tubular, which is made of a formable steel grade 24, is expanded inside the lower end of an existing well tubular 25 using an expansion mandrel 26 having a conical ceramic outer surface having a semi top angle A which is 10° and 40°, and preferably between 20° and 30°. The upper well tubular 25 has been cemented within the wellbore 28 and as a result of the expansion process the lower well tubular obtains a surplus expansion so that its inner diameter becomes larger than the outer diameter of the mandrel 26 and the expanded lower tubular 24 is firmly pressed against the overlapping lower part 27 of

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the upper tubular 25 so that a reliable electrical connection is created between the lower and upper well tubulars 24 and 25.

FIG. 3 illustrates a location where a lower tubular 30 has been expanded within a widened lower end 31 of an upper well tubular 32 and an electrical insulation sleeve 33 is arranged between the co-axial tubular parts.

A ring-shaped electrical power booster station 34 is arranged within the widened lower end 31 of the upper tubular 32 just above the top of the lower tubular 30. The station 34 is equipped with electrodes 35 which establish an electrical connection between the tubulars 30 and 32.

FIG. 4 shows how a branch wellbore 40 is drilled away from a primary wellbore 41 through an opening 42 that has been milled in the primary well casing 43 and the surrounding cement annulus 44.

FIG. 5 shows how an expandable branch well liner 45 is expanded in the branch wellbore 40 of FIG. 4 by an expansion mandrel 46 which is similar to the mandrel 26 shown in FIG. 2.

As a result of the surplus expansion during the expansion process the branch well liner 45 is elastically pressed against the inner wall of the primary well casing 43 and to the rims of the opening 42 thereby establishing a firm electrical connection between the primary well casing 43 and the branch well liner 44 which connection remains reliable throughout the lifetime of the well.

FIG. 6 shows a branchpoint in a multilateral well system where a bifurcation element 50 or splitter is secured and electrically connected (optionally via an electric booster station as illustrated in FIG. 3) to an upper primary well casing 51.

A lower primary casing section 52 and a branch well liner 53 are each radially expanded by an expansion mandrel 54 inside the primary and branch wellbores such that the upper ends of the lower primary casing section 52 and said liner are firmly pressed against the lower branches of the bifurcation element 50 which serve as an electric contact and receptacle.

FIG. 7 shows an inflow section of a branch wellbore 60 where the branch well liner 61 has perforations 62 through which oil and/or gas is allowed to flow from the surrounding oil and/or gas bearing formation 63 into the wellbore 60 as illustrated by arrows 64.

An equipment carrier sleeve 65 is sealingly secured inside the liner 61 by means of a pair of expandable packers 66.

The sleeve 65 has perforations 67 and is surrounded by a movable sleeve-type valve body 68 which has perforations 69 which are, in the position shown in fig. 7, aligned with the perforations 67 of the sleeve 65. Because of the alignment of the perforations 67 and 69 oil and/or gas is permitted to flow into the wellbore 60.

FIG. 8 shows how the sleeve-type valve body 68 is moved such that the perforations 67 and 69 are unaligned and flow of oil and/or gas from the formation 63 into the wellbore 60 is interrupted.

The motion of the sleeve type valve body 68 is achieved by an electrical actuator 70 which is powered by a rechargeable lithium-ion high temperature battery 71, which has one electrode 72 which is electrically connected to the surrounding formation and another electrode 73 which is electrically connected to the liner 61.

The electrical direct current (DC) power which is transmitted via the primary casing (not shown) to the branch well liner 61 is used to trickle charge the battery 71. The battery

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71 powers the valve actuator 70 and optionally also flow, pressure, temperature, composition, reservoir imaging and/or seismic equipment (not shown) carried by the sleeve 65 and signals generated by the equipment are transmitted to surface monitoring equipment by transmission of VLC or ELC pulsed electromagnetic signals which involve voltage level oscillations around the DC voltage level of the branch well liner 61 via the electrode 72 and said liner 61 to the primary well casing (not shown) and an electrical cable connected to the upper end of said casing (as is shown in FIG. 1) to surface monitoring and/or control equipment.

In the example shown in FIG. 7 the battery 71 is a tubular ceramic lithium-ion high-temperature battery and a series of reservoir imaging sensors 75 are embedded in the formation 63 surrounding the wellbore 60. These sensors 75 transmit and/or receive signals via inductive couplers 76 which are connected to signal processing equipment (not shown) mounted on the sleeve 65. Said processing equipment is able to actuate the valve body 68 and/or to transmit electric reservoir imaging data acquired by the sensors 75 via the wall of the well liner 61 and well tubulars in the primary or mother wellbore to production monitoring equipment at the platform or other surface facilities as illustrated in FIG. 1.

We claim:

1. A multilateral well and electric transmission system, comprising:

a primary wellbore in which a primary well tubular is arranged; and

a branch wellbore in which a branch well tubular is arranged;

wherein the branch well tubular is connected in an electrically conductive manner to the primary well tubular such that the primary and branch well tubulars form a link for transmission of electrical power and/or signals between the primary and branch wellbore;

wherein the primary and branch well tubulars form a link for transmitting low voltage power from a first pole of an electrical power source which is electrically connected to the primary well tubular to electrically powered equipment within the branch wellbore which is electrically connected to the branch well tubular, and wherein a second pole of the electrical power source and the branch well tubulars are electrically connected to the earth;

wherein the electrically powered equipment comprises a re-chargeable battery which is trickle-charged by the low voltage electrical power transmitted via the well tubulars;

wherein the electrically powered equipment comprises measuring and/or control equipment which is powered by a rechargeable lithium-ion high-temperature battery and is mounted on an equipment carrier module which is removably secured within the branch well tubular such that one electrode of the battery is electrically connected to the branch well tubular and another electrode of the battery is electrically connected to the subsurface earth formation surrounding the branch wellbore;

wherein the equipment carrier module formed by a sleeve which is removably connected within the branch well tubular by means of a number of expandable clamps; and

wherein the sleeve spans an inflow area of the branch wellbore where the branch well tubular is perforated, the expandable clamps consist of a pair of expandable packers which seal off an annular space between the

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branch well tubular and sleeve near each end of the sleeve and wherein the sleeve is provided with one or more fluid inlet ports which can be opened and closed by one or more valves which are powered by the rechargeable battery.

2. The multilateral well and electric transmission system of claim 1, wherein the branch well tubular is a radially expandable tubular which is made of an electrically conductive material and which is radially expanded within the branch well during installation and wherein an electrically conductive receptacle is arranged at or near a branchpoint such that the expanded branch well tubular is pressed into electrical contact with the receptacle as a result of the expansion process.

3. The multilateral well and electric transmission system of claim 2, wherein the receptacle is formed by the primary well tubular itself and the branch tubular has a downstream end which is radially expanded against the inner wall of the primary well tubular and extends through a window in the primary well tubular into the branch wellbore.

4. The multilateral well and electric transmission system of claim 2, wherein the receptacle is formed by a tubular branch section of a bifurcation element, which bifurcation element has a primary section which is electrically connected to the primary well tubular and the tubular branch section extends from the primary wellbore into the branch wellbore.

5. The multilateral well and electric transmission system of claim 2, wherein the primary and branch well tubulars are made of a formable steel grade and the branch well tubular is expanded during installation such that the expanded branch well tubular has an inner diameter which is at least 0.9 times the inner diameter of the primary well tubular.

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6. The multilateral well and electric transmission system of claim 1, wherein at least one of the primary and branch well tubulars is equipped with at least one electrical booster station, which station spans an electrically non-conductive section of the well tubular and which station is electrically connected to an electrically conductive parts of the well tubular at both sides of the electrically non-conductive section thereof.

7. The multilateral well and electric transmission system of claim 6, wherein the electrically non-conductive section of the well tubular is formed by an electrically non-conductive annular seal which is arranged between overlapping co-axial sections of the well tubular and wherein the electrical booster station is arranged within the outermost section of the well tubular near the end of the innermost section of the well tubular such that one electrode of the electrical booster station is connected to said outermost section and another electrode of said station is electrically connected to said innermost section.

8. The multilateral well and electrical transmission system of claim 7, which comprises a plurality of branch wellbores and a plurality of electrical booster stations.

9. A sleeve-type equipment carrier module for use in a multilateral well and electric transmission system according to claim 1, which module is sealingly securable in an inflow region of the well and comprises one or more fluid inlet ports which can be opened and closed by one or more valves which are powered by a rechargeable battery which is in use trickle charged by transmitting low voltage electrical power through tubulars in the primary and branch wellbore.

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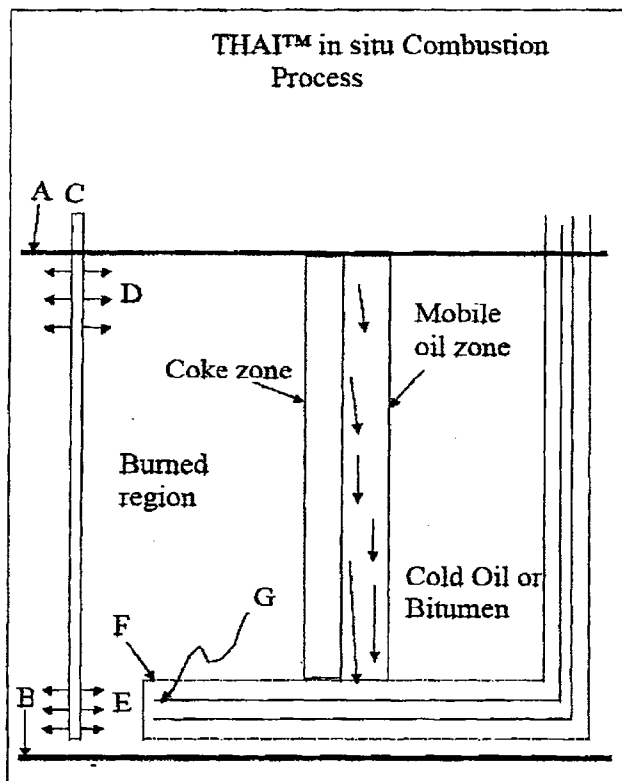
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(54) Title: DILUENT-ENHANCED IN-SITU COMBUSTION HYDROCARBON RECOVERY PROCESS



(57) Abstract: A modified process for recovering oil from an underground reservoir using the toe-to-heel in situ combustion process. A diluent, namely a hydrocarbon condensate, is injected within a horizontal wellbore portion, preferably proximate the toe, of a vertical-horizontal well pair, or alternatively into an adjacent injection well, or both, to increase mobility of oil.

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For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.

**DILUENT-ENHANCED IN-SITU COMBUSTION
HYDROCARBON RECOVERY PROCESS**

5 FIELD OF THE INVENTION

This invention relates to a process for improved productivity when undertaking oil recovery from an underground reservoir by the toe-to-heel in situ combustion process employing a horizontal production well, such as disclosed in U.S. Patent
10 Nos. 5,626,191 and 6,412,557. More particularly, it relates to an in situ combustion process in which a diluent, namely a hydrocarbon condensate, is injected at the toe of a vertical-horizontal well pair adapted for use in an in situ combustion process.

15 BACKGROUND OF THE INVENTION AND DESCRIPTION OF THE PRIOR ART

U.S. Patents 5,626,191 and 6,412,557, incorporated herein in their entirety, disclose in situ combustion processes for producing oil from an underground reservoir (100) utilizing an injection well (102) placed relatively high in an oil
20 reservoir (100) and a production well (103-106) completed relatively low in the reservoir (100). The production well has a horizontal leg (107) oriented generally perpendicularly to a generally linear and laterally extending upright combustion front propagated from the injection well (102). The leg (107) is positioned in the path of the advancing combustion front. Air, or other oxidizing gas, such as
25 oxygen-enriched air, is injected through wells 102, which may be vertical wells, horizontal wells or combinations of such wells.

The process of U.S. Patent 5,626,191 is called "THAI™", an acronym for "toe-to-heel air injection" and the process of U.S. Patent 6,412,557 is called "Capri™", the
30 Trademarks being held by Archon Technologies Ltd., a subsidiary of Petrobank Energy and Resources Ltd., Calgary, Alberta, Canada.

What is needed is one or more methods to increase productivity when undertaking oil recovery from an underground reservoir by the toe-to-heel in situ combustion process employing horizontal production wells .

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SUMMARY OF THE INVENTION

10 The invention, in a broad embodiment, comprises injecting a diluent in the form of a hydrocarbon condensate via tubing at the toe of the toe-to-heel in situ combustion process employed a horizontal production well , which adds to well productivity and advantageously results in various production economies over the THAI and CAPRI processes to date employed.

15 A hydrocarbon condensate is typically a low-density, high-API gravity liquid hydrocarbon phase that generally occurs in association with natural gas. Its presence as a liquid phase depends on temperature and pressure conditions in the reservoir allowing condensation of liquid from vapor.

20 The production of condensate from reservoirs can be complicated because of the pressure sensitivity of some condensates. Specifically, during production, there is a risk of the condensate changing from gas to liquid if the reservoir pressure (and thus temperature) drops below the dew point during production. Reservoir pressure (and thus temperature) can be maintained by fluid injection if gas
25 production is preferable to liquid production. Gas produced in association with condensate is called wet gas. The API gravity of condensate is typically 50 degrees to 120 degrees.

The benefit of injection a high-API hydrocarbon condensate (40+ API Gravity) into
30 the tubing in a THAI™ or CAPRI™ In situ hydrocarbon extraction method is that a

steam generator or water treatment facilities, as are typically required in THAI™ and CAPRI™ in situ hydrocarbon extraction methods, would not be required. This results in a significant expense savings, not only in avoiding the cost of having to divert a portion of the produced hydrocarbon to produce heated steam, but also in having to have the necessary steam generation equipment and pollution control equipment present to do so. Process operations costs would not be increased since the diluent in liquid form is purchased anyway, and typically in prior art methods involving THAI and CAPRI, mixed with the extracted hydrocarbon at the surface in order to better pump the hydrocarbon to storage facilities or refineries.

The diluent would dissolve in the liquid oil in the horizontal wellbore and reduce its viscosity, which would advantageously reduce pressure drop in the horizontal well. It would also reduce the density of the oil, facilitating its rise to the surface by gas-lift.

The addition of a diluent in the form of a hydrocarbon condensate, preferably a liquid, via tubing at the toe of a horizontal production well in a toe-to-heel in situ combustion hydrocarbon recovery process, may be done in combination with any of the steam, water, or oxidizing gas injection methods disclosed in any of US Provisional patent application 60/577,779 filed June 7, 2004 and/or Patent Cooperation Patent Application PCT/CA2005/000883 filed June 6, 2005, each of which are incorporated herein by reference in their respective entireties.

Accordingly, in one broad embodiment of the method of the present invention, the invention comprises a process for extracting liquid hydrocarbons from an underground reservoir comprising the steps of:

- (a) providing at least one injection well for injecting an oxidizing gas into the underground reservoir;
- 5 (b) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is
- 10 closer to the injection well than the heel portion;
- (c) injecting an oxidizing gas through the injection well to conduct in situ combustion, so that combustion gases are produced so as to cause the combustion gases to progressively advance as a front,
- 15 substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;
- (d) providing a tubing inside the production well for the purpose of
- 20 injecting a hydrocarbon condensate into said horizontal leg portion of said production well;
- (e) injecting said hydrocarbon condensate into said tubing so that said condensate is conveyed proximate said toe portion of said
- 25 horizontal leg portion via said tubing ; and
- (f) recovering hydrocarbons in the horizontal leg of the production well from said production well.

In a further broad embodiment of the invention, the present invention comprises a process for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:

- 5 (a) providing at least one injection well for injecting an oxidizing gas into an upper part of an underground reservoir;
- (b) providing at least one injection well for a hydrocarbon condensate diluent into a lower part of an underground reservoir;
- 10 (c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the
- 15 opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;
- (d) injecting an oxidizing gas through the injection well for in situ combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;
- 20
- 25 (e) injecting a hydrocarbon condensate diluent, into said injection well ;
and

- (f) recovering hydrocarbons in the horizontal leg of the production well from said production well.

5 In a still further embodiment of the invention, the present invention comprises the combination of the above steps of injecting a hydrocarbon diluent to the formation via the injection well, and as well injecting a medium via tubing in the horizontal leg. Accordingly, in this further embodiment the present invention comprises a method for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:

10

a) providing at least one injection well for injecting an oxidizing gas into an upper part of an underground reservoir;

15

b) providing at least one injection well for a hydrocarbon diluent into a lower part of an underground reservoir;

20

c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;

25

d) providing a tubing inside the production well for the purpose of injecting a hydrocarbon condensate diluent into said horizontal leg portion of said production well;

5 e) injecting an oxidizing gas through the injection well for in situ combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;

10 f) injecting a hydrocarbon condensate diluent into said injection well and into said tubing; and

(g) recovering hydrocarbons in the horizontal leg of the production well from said production well.

15 The hydrocarbon condensate contemplated is preferably a condensate selected from the group of condensates consisting of ethane, butanes, pentanes, heptanes, hexanes, octanes, and higher molecular weight hydrocarbons, or mixtures thereof, but may be any other hydrocarbon diluent, such as volatile hydrocarbons such as naphtha or gasoline.

20 **BRIEF DESCRIPTION OF THE DRAWINGS**

Figure 1 is a schematic of the THAI™ in situ combustion process with labeling as follows:

25 Item A represents the top level of a heavy oil or bitumen reservoir, and B represents the bottom level of such reservoir/formation. C represents a vertical well with D showing the general injection point of an oxidizing gas such as air.

E represents a general location for the injection of steam or a non-oxidizing gas into the reservoir. This is part of the present invention.

5 F represents a partially perforated horizontal well casing. Fluids enter the casing and are typically conveyed directly to the surface by natural gas lift through another tubing located at the heel of the horizontal well (not shown).

10 G represents a tubing placed inside the horizontal leg. The open end of the tubing may be located near the end of the casing, as represented, or elsewhere. The tubing can be 'coiled tubing' that may be easily relocated inside the casing. This is part of the present invention.

15 The elements E and G are part of the present invention and steam or non-oxidizing gas may be injected at E and/or at G. E may be part of a separate well or may be part of the same well used to inject the oxidizing gas. These injection wells may be vertical, slanted or horizontal wells or otherwise and each may serve several horizontal wells.

20 For example, using an array of parallel horizontal leg as described in U.S. Patents 5,626,191 and 6,412,557, the steam, water or non-oxidizing gas may be injected at any position between the horizontal legs in the vicinity of the toe of the horizontal legs.

25 Figure 2 is a schematic diagram of the Model reservoir. The schematic is not to scale. Only an 'element of symmetry' is shown. The full spacing between horizontal legs is 50 meters but only the half-reservoir needs to be defined in the STARS™ computer software. This saves computing time. The overall dimensions of the Element of Symmetry are:

length A-E is 250 m; width A-F is 25 m; height F-G is 20 m.

The positions of the wells are as follows:

- 5 Oxidizing gas injection well J is placed at B in the first grid block 50 meters (A-B) from a corner A. The toe of the horizontal well K is in the first grid block between A and F and is 15 m (B-C) offset along the reservoir length from the injector well J. The heel of the horizontal well K lies at D and is 50 m from the corner of the reservoir, E. The horizontal section of the horizontal well K is 135 m (C-D) in
10 length and is placed 2.5 m above the base of the reservoir (A-E) in the third grid block.

- The Injector well J is perforated in two (2) locations. The perforations at H are injection points for oxidizing gas, while the perforations at I are injection points for
15 steam or non-oxidizing gas. The horizontal leg (C-D) is perforated 50% and contains tubing open near the toe (not shown, see Figure 1).

Figure 3 is a graph plotting oil production rate vs. CO₂ rate in the produced gas, drawing on Example 7 discussed below.

20

DESCRIPTION OF THE PREFERRED EMBODIMENT

- The operation of the THAI™ process has been described in U.S. Patents
25 5,626,191 and 6,412,557 and will be briefly reviewed. The oxidizing gas, typically air, oxygen or oxygen-enriched air, is injected into the upper part of the reservoir. Coke that was previously laid down consumes the oxygen so that only oxygen-free gases contact the oil ahead of the coke zone. Combustion gas temperatures of typically 600 °C. and as high as 1000 °C. are achieved from the high-temperature

oxidation of the coke fuel. In the Mobile Oil Zone (MOZ), these hot gases and steam heat the oil to over 400 °C, partially cracking the oil, vaporizing some components and greatly reducing the oil viscosity. The heaviest components of the oil, such as asphaltenes, remain on the rock and will constitute the coke fuel
5 later when the burning front arrives at that location. In the MOZ, gases and oil drain downward into the horizontal well, drawn by gravity and by the low- pressure sink of the well. The coke and MOZ zones move laterally from the direction from the toe towards the heel of the horizontal well. The section behind the combustion front is labeled the Burned Region. Ahead of the MOZ is cold oil.

10

With the advancement of the combustion front, the Burned Zone of the reservoir is depleted of liquids (oil and water) and is filled with oxidizing gas. The section of the horizontal well opposite this Burned Zone is in jeopardy of receiving oxygen which will combust the oil present inside the well and create extremely high
15 wellbore temperatures that would damage the steel casing and especially the sand screens that are used to permit the entry of fluids but exclude sand. If the sand screens fail, unconsolidated reservoir sand will enter the wellbore and necessitate shutting in the well for cleaning-out and remediation with cement plugs. This operation is very difficult and dangerous since the wellbore can contain explosive
20 levels of oil and oxygen.

In order to quantify the effect of fluid injection into the horizontal wellbore, a number of computer numerical simulations of the process were conducted. Steam was injected at a variety of rates into the horizontal well by two methods: 1. via
25 tubing placed inside the horizontal well, and 2. via a separate well extending near the base of the reservoir in the vicinity of the toe of the horizontal well. Both of these methods reduced the predilection of oxygen to enter the wellbore but gave surprising and counterintuitive benefits: the oil recovery factor increased and build-

up of coke in the wellbore decreased. Consequently, higher oxidizing gas injection rates could be used while maintaining safe operation.

5 It was found that both methods of adding steam to the reservoir provided advantages regarding the safety of the THAI™ Process by reducing the tendency of oxygen to enter the horizontal wellbore. It also enabled higher oxidizing gas injection rates into the reservoir, and higher oil recovery.

10 Extensive computer simulation of the THAI™ Process was undertaken to evaluate the consequences of reducing the pressure in the horizontal wellbore by injecting steam or non-oxidizing gas. The software was the STARS™ In Situ Combustion Simulator provided by the Computer Modelling Group, Calgary, Alberta, Canada.

Table 4. List of Model Parameters.

15

Simulator: STARS™ 2003.13, Computer Modelling Group Limited

Model dimensions:

Length 250 m, 100 grid blocks, each

Width 25 m, 20 grid blocks

Height 20 m, 20 grid blocks

Grid Block dimensions: 2.5 m x 2.5 m x 1.0 m (LWH).

Horizontal Production Well:

A discrete well with a 135 m horizontal section extending from grid block 26,1, 3 to 80,1,3

The toe is offset by 15 m from the vertical air injector..

Vertical Injection Well:

Oxidizing gas(air) injection points: 20, 1, 1:4 (upper 4-grid blocks)

Oxidizing gas injection rates: 65,000 m3/d, 85,000 m3/d or 100,000 m3/d

Steam injection points: 20, 1, 19:20 (lower 2-grid blocks)

Rock/fluid Parameters:

Components: water, bitumen, upgrade, methane, CO₂, CO/ N₂, oxygen, coke

Heterogeneity: Homogeneous sand.

Permeability: 6.7 D (h), 3.4 D (v)

Porosity: 33 %

Saturations: Bitumen 80%, water 20%, gas Mole fraction 0.114

Bitumen viscosity: 340,000 cP at 10 °C.

Bitumen average molecular weight: 550 AMU

Upgrade viscosity: 664 cP at 10 °C.

Upgrade average molecular weight: 330 AMU

Physical Conditions:

Reservoir temperature: 20 °C.

Native reservoir pressure: 2600 kPa.

Bottomhole pressure: 4000 kPa.

Reactions:

1. 1.0 Bitumen $\longrightarrow$ 0.42 Upgrade + 1.3375 CH₄ + 20 Coke
2. 1.0 Bitumen + 16 O₂ + 0.05 $\longrightarrow$ 12.5 water + 5.0 CH₄ + 9.5 CO₂ + 0.5 CO/N₂ + 15 Coke
3. 1.0 Coke + 1.225 O₂ $\longrightarrow$ 0.5 water + 0.95 CO₂ + 0.05 CO/N₂

EXAMPLES5 **Example 1**

Table 1a shows the simulation results for an air injection rate of 65,000 m³/day (standard temperature and pressure) into a vertical injector (E in Figure 1). The case of zero steam injected at the base of the reservoir at point I in well J is not
 10 part of the present invention. At 65,000 m³/day air rate, there is no oxygen entry

into the horizontal wellbore even with no steam injection and the maximum wellbore temperature never exceeds the target of 425 °C.

However, as may be seen from the data below, injection of low levels of steam at levels of 5 and 10 m³/day (water equivalent) at a point low in the reservoir (E in Figure 1) provides substantial benefits in higher oil recovery factors, contrary to intuitive expectations. Where the injected medium is steam, the data below provides the volume of the water equivalent of such steam, as it is difficult to otherwise determine the volume of steam supplied as such depends on the pressure at the formation to which the steam is subjected to. Of course, when water is injected into the formation and subsequently becomes steam during its travel to the formation, the amount of steam generated is simply the water equivalent given below, which typically is in the order of about 1000x (depending on the pressure) of the volume of the water supplied.

Table 1a: AIR RATE 65,000 m³/day- Steam injected at reservoir base.

Steam Injection Rate m ³ /day (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
0	410	90	0	35.1	28.3
5	407	79	0	38.0	29.0
10	380	76	0	43.1	29.8

* Not part of the present invention.

Example 2

Table 1b shows the results of injecting steam into the horizontal well via the internal tubing, G, in the vicinity of the toe while simultaneously injecting air at 65,000 m³/day (standard temperature and pressure) into the upper part of the reservoir. The maximum wellbore temperature is reduced in relative proportion to the amount of steam injected and the oil recovery factor is increased relative to the base case of zero steam. Additionally, the maximum volume percent of coke deposited in the wellbore decreases with increasing amounts of injected steam. This is beneficial since pressure drop in the wellbore will be lower and fluids will flow more easily for the same pressure drop in comparison to wells without steam injection at the toe of the horizontal well.

Table 1b. AIR RATE 65,000 m³/day- Steam injected in well tubing.

Steam Injection Rate m ³ /day (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
0	410	90	0	35.1	28.6
5	366	80	0	43.4	30.0
10	360	45	0	43.4	29.8

* Not part of the present invention.

Example 3

15

In this example, the air injection rate was increased to 85,000 m³/day (standard temperature and pressure) and resulted in oxygen breakthrough as shown in Table 2a. An 8.8% oxygen concentration was indicated in the wellbore for the base case of zero steam injection. Maximum wellbore temperature reached 1074 °C and coke was deposited decreasing wellbore permeability by 97%. Operating with the simultaneous injection of 12 m³/day (water equivalent) of steam at the

20

base of the reservoir via vertical injection well C (see Fig. 1) provided an excellent result of zero oxygen breakthrough, acceptable coke and good oil recovery.

Table 2a: AIR RATE 85,000 m³/day- Steam injected at reservoir base.

Steam Injection Rate m ³ /d (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
0	1074	97	8.8		
5	518	80	0		
12	414	43	0	36.1	33.4

* Not part of the present invention.

5

Example 4.

Table 2b shows the combustion performance with 85,000 m³/day air (standard temperature and pressure) and simultaneous injection of steam into the wellbore via an internal tubing G (see Fig. 1) . Again 10 m³/day (water equivalent) of steam was needed to prevent oxygen breakthrough and an acceptable maximum wellbore temperature.

10

Table 2b AIR RATE 85,000 m³/d. Steam injected in well tubing.

Steam Injection Rate m ³ /d (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
0	1074	100	8.8		
5	500	96	1.8		

10 407 45 0 37.3 33.2

* Not part of the present invention.

Example 5

- 5 In order to further test the effects of high air injection rates, several runs were conducted with 100,000 m³/day air injection. Results in Table 3a indicate that with simultaneous steam injection at the base of the reservoir (ie at location B-E in vertical well C-ref. Fig. 1), 20 m³/day (water equivalent) of steam was required to stop oxygen breakthrough into the horizontal leg, in contrast to only 10 m³/day steam (water equivalent) at an air injection rate of 85,000 m³/day.
- 10

Table 3a: AIR RATE 100,000 m³/day-Steam injected at reservoir base.

Steam Injection Rate m ³ /day (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
*0	1398	100	10.4		
5	1151	100	7.2		
10	1071	100	6.0		
20	425	78	0	34.5	35.6

* Not part of the present invention.

15

Example 6

Table 3b shows the consequence of injecting steam into the well tubing G (ref. Fig. 1) while injecting 100,000 m³/day air into the reservoir. Identically with steam

injection at the reservoir base, a steam rate of 20 m³/day (water equivalent) was required in order to prevent oxygen entry into the horizontal leg.

Table 3b AIR RATE 100,000 m³/d. Steam injected in well tubing.

Steam Injection Rate m ³ /day (water equivalent)	Maximum well Temperature, ° C.	Maximum coke in wellbore %	Maximum Oxygen in wellbore %	Bitumen recovery Factor % OOIP	Average oil Production Rate m ³ /day
0	1398	100	10.4		
5	997	100	6.0		
10	745	100	3.8		
20	425	38	0	33.9	35.6

5

Example 7

Table 4 below shows comparisons between injecting oxygen and a combination of non-oxidizing gases, namely nitrogen and carbon dioxide, into a single vertical injection well in combination with a horizontal production well in the THAI™ process via which the oil is produced, as obtained by the STARS™ In Situ Combustion Simulator software provided by the Computer Modelling Group, Calgary, Alberta, Canada. The computer model used for this example was identical to that employed for the above six examples, with the exception that the modeled reservoir was 100 meters wide and 500 meters long. Steam was added at a rate of 10 m³/day via the tubing in the horizontal section of the production well for all runs.

20

Test #	Injection Rate, km ³ /day			Mol % Oxygen	Mol % CO ₂	Total Injection Rate, km ³ /day	Production Rate, km ³ /day		Produced Gas Mol % CO ₂	Oil Rate m ³ /day (1-year)	Cumulative Oil Recovery m ³
	O ₂	CO ₂	N ₂	Injected	Injected	km ³ /day	CO ₂	N ₂	CO ₂	m ³ /day (1-year)	m ³
1	17.85	0	67.15	21	0	85	13.1	67.2	16.3	41	9700
2	8.93	33.57	0	21	79	42.5	37.9	0.0	96.0	54	12780
3	25	0	0	100	0	25	21.3	0.0	96.0	47	10078
4	17.85	67.15	0	21	79	85	75.0	0.0	96.0	136	20000
5	42.5	0	0	100	0	42.5	38.1	0.0	96.0	57	12704
6	42.5	42.5	0	50	50	85	74.2	0.0	96.0	113	28104
7	8.93	42.5	33.57	11	50	85	47.2	33.6	57.4	70	12000

As may be seen from above Table 4 comparing Run 1 and Run 2, when the oxygen and inert gas are reduced by 50% as in Run2, the oil recovery is nevertheless the same as in Run 1, providing that the inert gas is CO₂. This means that the gas compression costs are cut in half in Run 2, while oil is produced faster.

As may further be seen from above Table 4, Run #1 having 17.85 molar % of oxygen and 67.15% nitrogen injected into the injection well, estimated oil recovery rate was 41 m³/day. In comparison, using a similar 17.85 molar% oxygen injection with 67.15 molar % carbon dioxide as used in Run #4, a 3.3 times increase in oil production (136 m³/day) is estimated as being achieved.

As may be further seen from Table 4 above, when equal amounts of oxygen and CO₂ are injected as in Run 6, still with a total injected volume of 85,000 m³/day, oil recovery was increased 2.7-fold.

Run 7 shows the benefit of adding CO₂ to air as the injectant gas. Compared with Run 1, oil recovery was increased 1.7-fold without increasing compression costs.

The benefit of this option is that oxygen separation equipment is not needed.

Referring now to Figure 3, which is a graph showing a plot of oil production rate versus CO₂ rate in the produced gas (drawing on Example 7 above), there is a strong correlation between these parameters for in situ combustion processes. CO₂ production rate depends upon two CO₂ sources: the injected CO₂ and the CO₂ produced in the reservoir from coke combustion, so there is a strong synergy between CO₂ flooding and in situ combustion even in reservoirs with immobile oils, which is the present case.

SUMMARY

For a fixed amount of steam injection, the average daily oil recovery rate increased with air injection rate. This is not unexpected since the volume of the sweeping fluid is increased. However, it is surprising that the total oil recovered decreases as air rate is increased. This is during the life of the air injection period (time for the combustion front to reach the heel of the horizontal well). Moreover, with carbon dioxide injected in the vertical well, and/or in the horizontal production well, production rates improved production rates can be expected.

Although the disclosure described and illustrates preferred embodiments of the invention, it is to be understood that the invention is not limited to these particular embodiments. Many variations and modifications will now occur to those skilled in the art. For definition of the invention, reference is to be made to the appended claims.

The embodiments of the invention in which an exclusive property or privilege is claimed are defined as follows:

1. A process for extracting liquid hydrocarbons from an underground reservoir comprising the steps of:
 - (a) providing at least one injection well for injecting an oxidizing gas into the underground reservoir;
 - (b) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;
 - (c) injecting an oxidizing gas through the injection well to conduct in situ combustion, so that combustion gases are produced so as to cause the combustion gases to progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;
 - (d) providing a tubing inside the production well within said vertical leg and at least a portion of said horizontal leg for the purpose of injecting a hydrocarbon condensate, into said horizontal leg portion of said production well proximate a combustion front formed at a horizontal distance along said horizontal leg of said production well;

- (e) injecting a hydrocarbon condensate diluent into said tubing so that said condensate is conveyed proximate said toe portion of said horizontal leg portion via said tubing ; and
 - (f) recovering hydrocarbons in the horizontal leg of the production well from said production well.
2. The process of Claim 1 wherein said hydrocarbon condensate diluent is a condensate selected from the group of condensates consisting of ethane, butanes, pentanes, heptanes, hexanes, octanes, and higher molecular weight hydrocarbons, or mixtures thereof.
 3. The process of Claim 1, wherein said hydrocarbon condensate is VAPEX.
 4. The process of Claim 1 wherein the injection well is a vertical, slant or horizontal well.
 5. The process of Claim 1, said step of injecting said hydrocarbon condensate further serves to pressurize said horizontal well to a pressure to permit injection of said medium into the underground reservoir.
 6. The process of claim 1, said step of injecting said hydrocarbon condensate comprises injecting said condensate at a temperature and pressure at which said condensate exists in liquid form.
 7. The process of claim 1, said step of injecting said hydrocarbon condensate comprises injecting said condensate at a temperature and pressure at which such condensate exists in gaseous form.

8. The process of claim 1 wherein said hydrocarbon condensate is injected into said tubing in combination with a medium selected from the group of mediums consisting of steam, water, or a non-oxidizing gas, or mixtures thereof.
9. The process of claim 1 wherein an open end of the tubing is in the vicinity of the toe of the horizontal section so as to permit delivery of said condensate to said toe.
10. The process of claim 1 or 9 wherein the tubing is partially pulled back or otherwise repositioned for the purpose of altering a point of injection of the condensate along the horizontal leg.
11. The process of Claim 1 wherein said condensate is injected continuously or periodically.
12. A process for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:
 - (a) providing at least one injection well for injecting an oxidizing gas into an upper part of an underground reservoir;
 - (b) said at least one injection well further adapted for injecting steam, a non-oxidizing gas, or water which is subsequently heated to steam, into a lower part of an underground reservoir;
 - (c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection

well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;

(d) injecting an oxidizing gas through the injection well for in situ combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;

(e) injecting a hydrocarbon condensate into said injection well; and

(f) recovering hydrocarbons in the horizontal leg of the production well from said production well.

13. A process for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:

(a) providing at least one oxidizing gas injection well for injecting an oxidizing gas into an upper part of an underground reservoir;

(b) providing at least one other injection well for injecting a hydrocarbon condensate into a lower part of an underground reservoir;

(c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its

connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the oxidizing gas injection well than the heel portion;

(d) injecting an oxidizing gas through the oxidizing injection well for in situ combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;

(e) injecting a hydrocarbon condensate, into said other injection well; and

(f) recovering hydrocarbons in the horizontal leg of the production well from said production well.

14. The process of Claim 12 or 13 wherein said hydrocarbon condensate is a condensate selected from the group of condensates consisting of ethane, butanes, pentanes, heptanes, hexanes, octanes, and higher molecular weight hydrocarbons, or mixtures thereof.

15. A method for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:

(a) providing at least one injection well for injecting an oxidizing gas into an upper part of an underground reservoir;

- (b) said at least one injection well further adapted for injecting steam, a non-oxidizing gas, or water which is subsequently heated to steam, into a lower part of an underground reservoir;
- (c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;
- (d) providing a tubing inside the production well within said vertical leg and at least a portion of said horizontal leg for the purpose of injecting hydrocarbon condensate into said horizontal leg portion of said production well;
- (e) injecting an oxidizing gas through the injection well for in situ combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;
- (f) injecting a hydrocarbon condensate into said injection well and into said tubing; and
- (g) recovering hydrocarbons in the horizontal leg of the production well from said production well.

16. The method of claim 15 wherein said hydrocarbon condensate is a condensate selected from the group of condensates consisting of ethane, butanes, pentanes, heptanes, hexanes, octanes, and higher molecular weight hydrocarbons, or mixtures thereof.
17. The method of claim 15 wherein the injection well is a vertical, slant or horizontal well.
18. A method for extracting liquid hydrocarbons from an underground reservoir, comprising the steps of:
 - (a) providing at least one injection well for injecting an oxidizing gas into an upper part of an underground reservoir;
 - (b) providing at least one other injection well for injecting steam, a non-oxidizing gas, or water which is subsequently heated to steam, into a lower part of an underground reservoir;
 - (c) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;
 - (d) providing a tubing inside the production well within said vertical leg and at least a portion of said horizontal leg for the purpose of injecting a hydrocarbon condensate into said horizontal leg portion of said production well;

- (e) injecting an oxidizing gas through the injection well for in situ combustion, so that combustion gases are produced, wherein the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in the direction from the toe portion to the heel portion of the horizontal leg, and fluids drain into the horizontal leg;
 - (f) injecting a hydrocarbon condensate into said other injection well and into said tubing; and
 - (g) recovering hydrocarbons in the horizontal leg of the production well from said production well.
19. The method of claim 18 wherein said hydrocarbon condensate is a condensate selected from the group of condensates consisting of ethane, butanes, pentanes, heptanes, hexanes, octanes, and higher molecular weight hydrocarbons, or mixtures thereof.
20. The method of claim 18 wherein the injection well is a vertical, slant or horizontal well.

Figure 1. THAI™ in situ Combustion Process

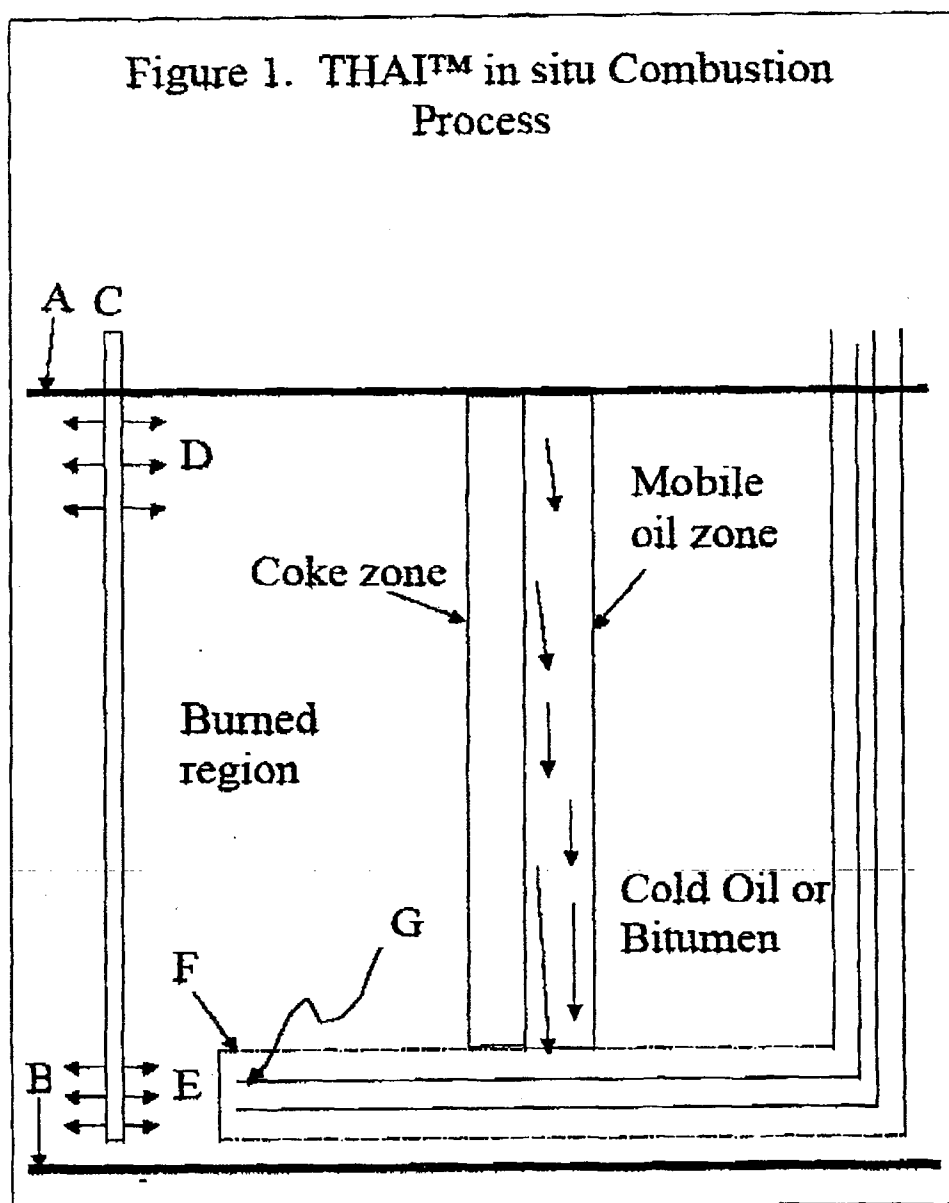


Figure 2. Reservoir Dimensions and Placement of Wells

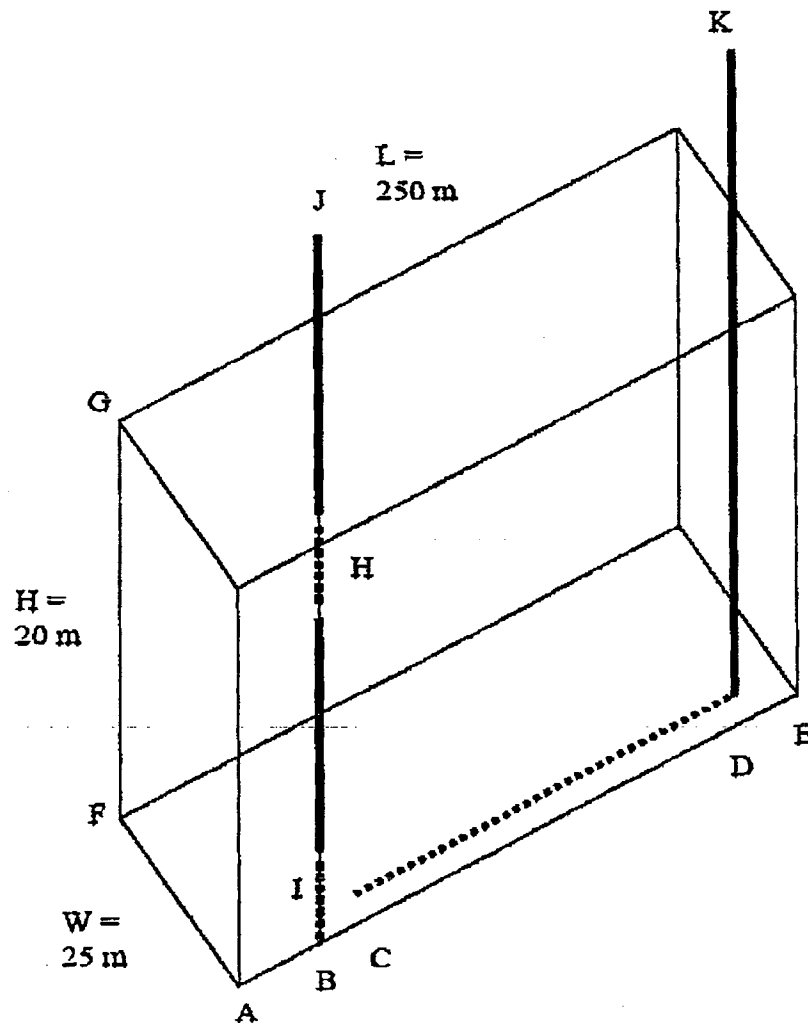
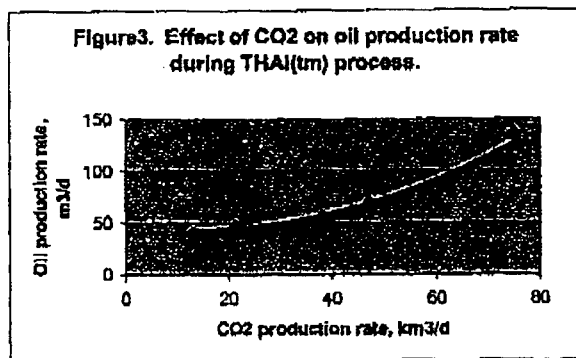


Figure 3. Graph Plotting Production Rate
versus CO₂ Rate in Produced Gas





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(12) **United States Patent**
Ayasse et al.

(10) Patent No.: **US 6,412,557 B1**
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(54) **OILFIELD IN SITU HYDROCARBON
UPGRADING PROCESS**

(75) Inventors: **Conrad Ayasse, Calgary (CA);
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1997.

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(52) U.S. Cl. **166/261; 166/262; 166/272.3;
166/245**

(58) Field of Search **166/256, 261,
166/262, 272.3, 245**

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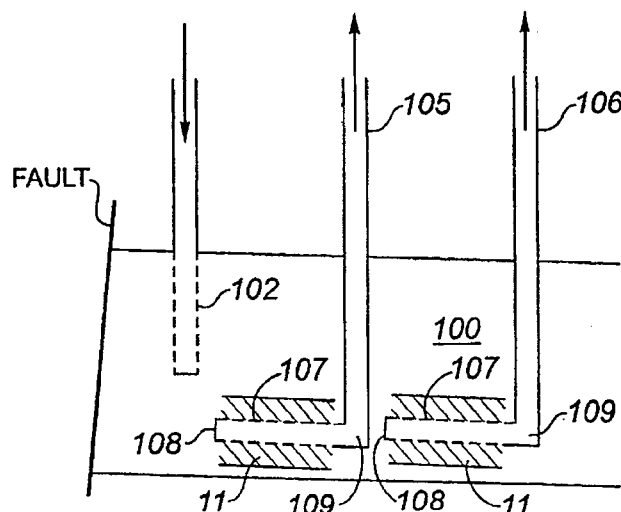
Primary Examiner—William Neuder

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(57) **ABSTRACT**

A well configuration is provided comprising an injection
well (102) completed relatively high in an oil reservoir (100)
and a production well (103-106) completed relatively low in
the reservoir (100). The production well has a horizontal leg
(107) oriented generally perpendicularly to a generally linear
and laterally extending, upright combustion front propa-
gated from the injection well (102). The leg (107) is posi-
tioned in the path of the advancing front. Oil upgrading
catalyst has been emplaced along the horizontal leg. The
production well (103-106) is maintained open, thereby
providing a low pressure sink which induces the front to
advance along the leg. The hot combustion gases react with
the commingled oil over the catalyst to provide in situ
upgrading.

16 Claims, 6 Drawing Sheets



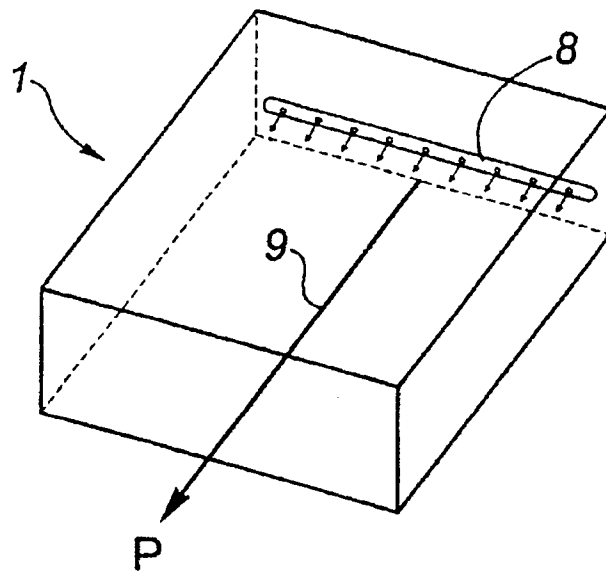


FIG. 1

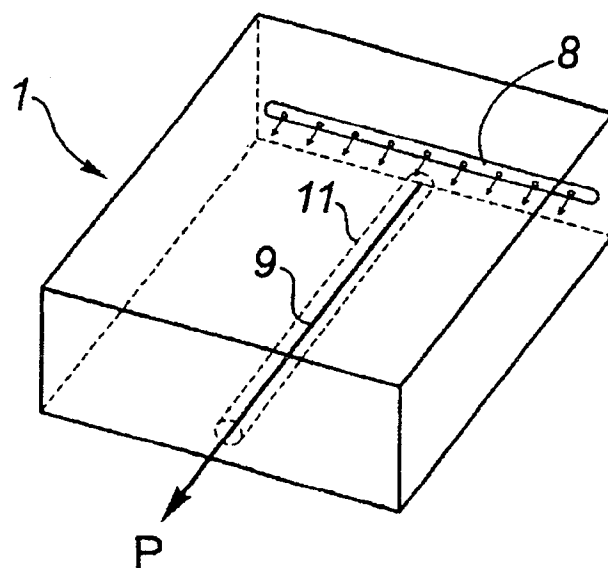


FIG. 2

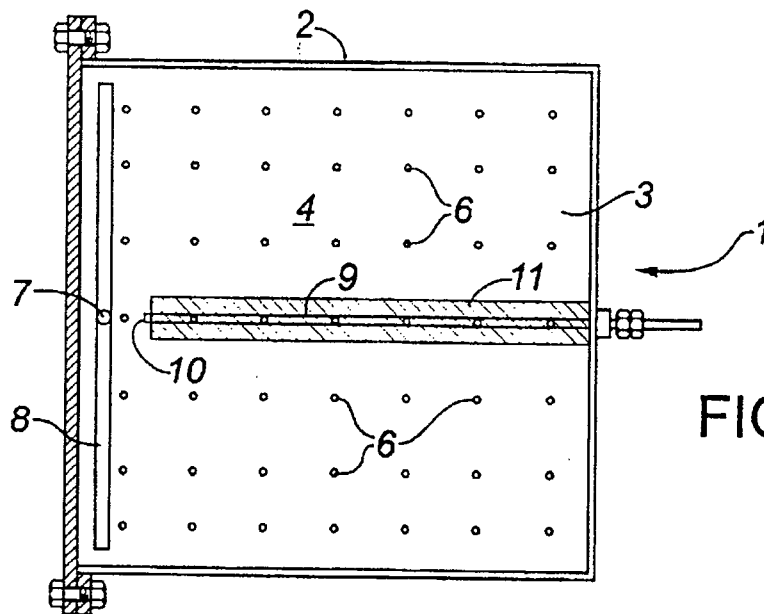


FIG. 3A

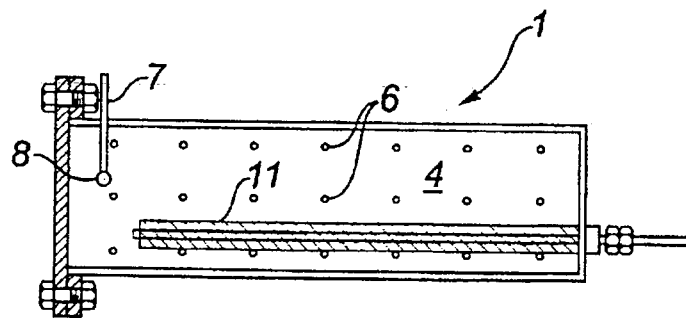


FIG. 3B

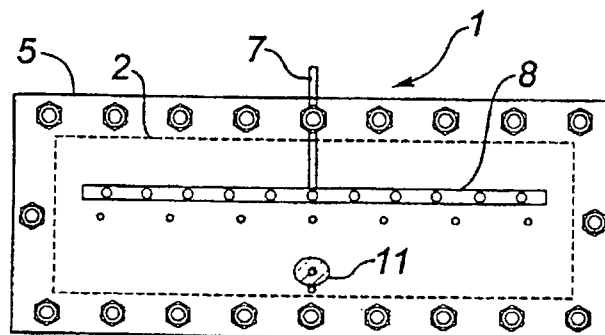


FIG. 3C

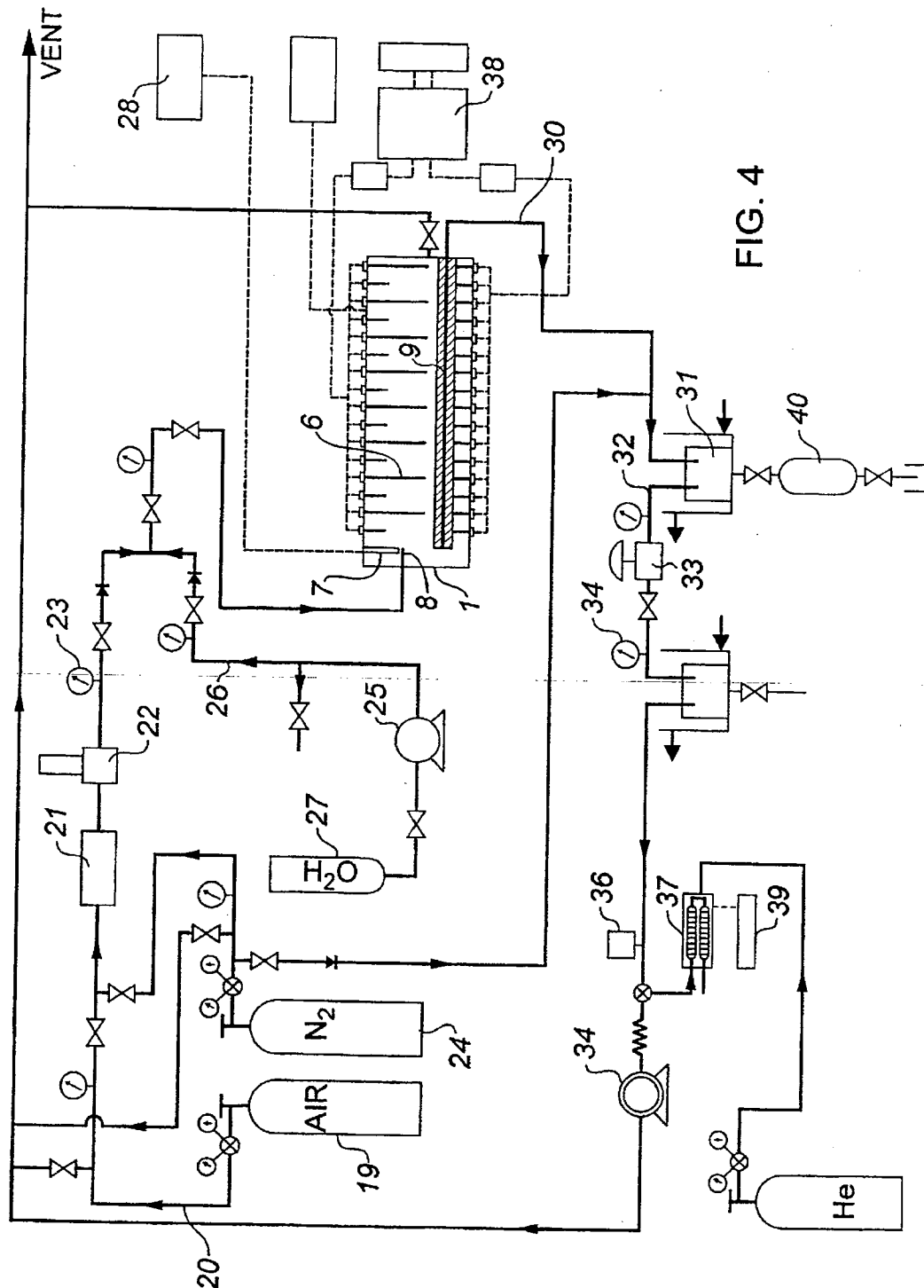


FIG. 4

FIG. 5A

BASE WOLF LAKE OIL

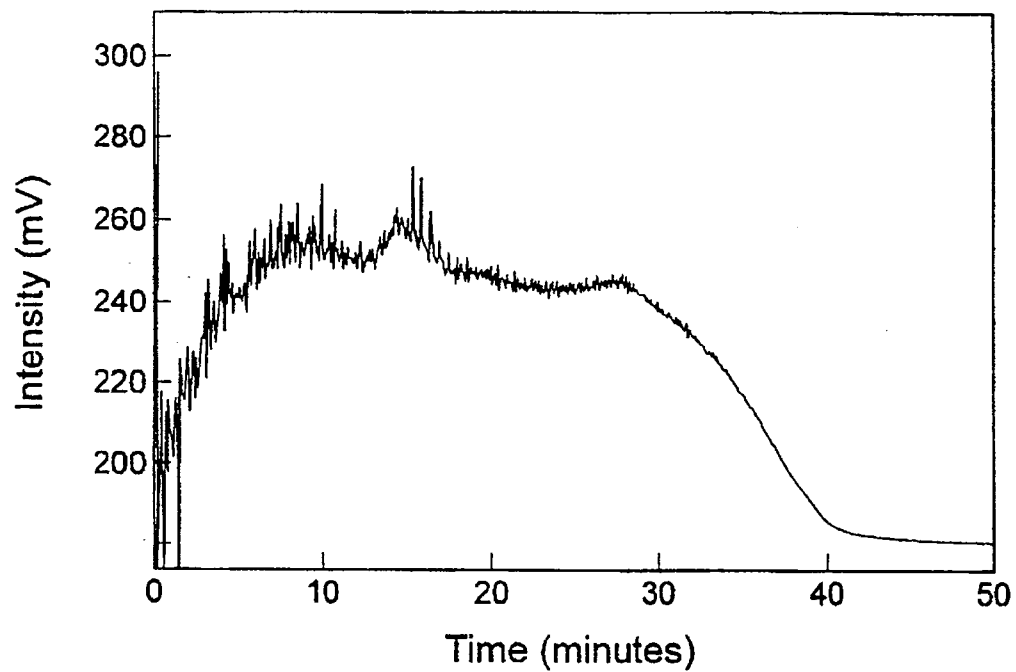


FIG. 5B

WET CATALYTIC ISC RUN 976

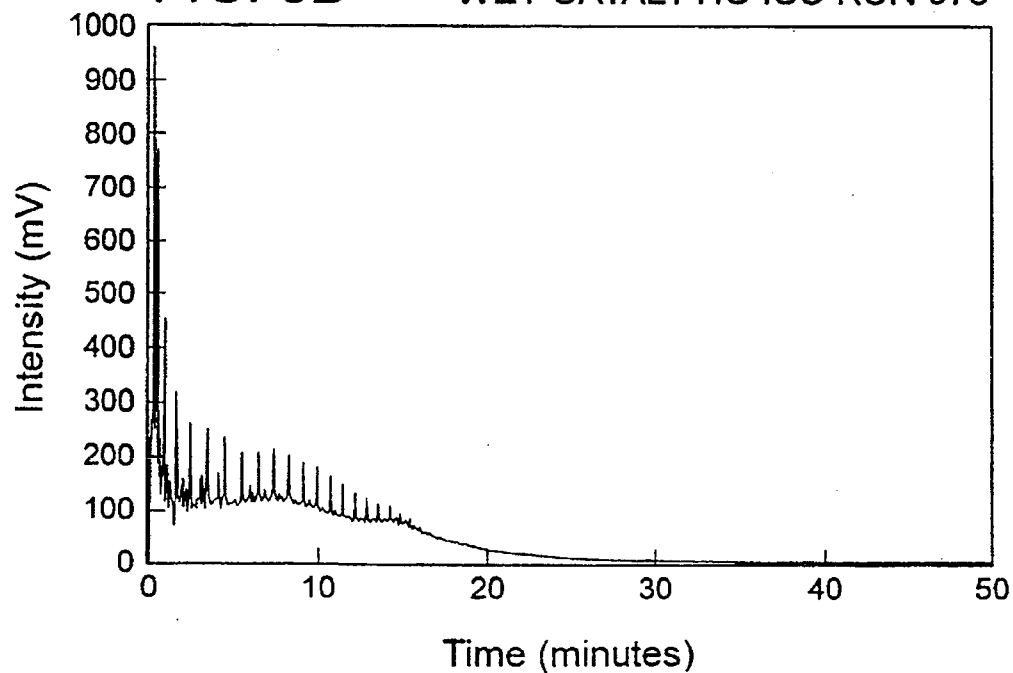


FIG. 8A

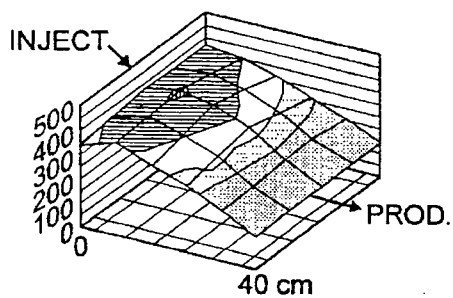


FIG. 8B

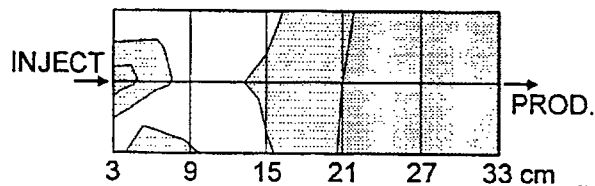


FIG. 8C

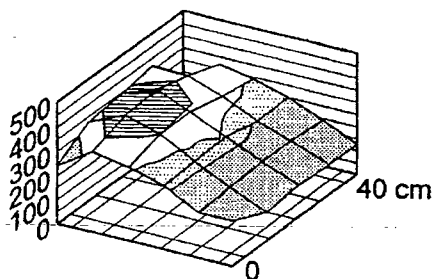


FIG. 8D

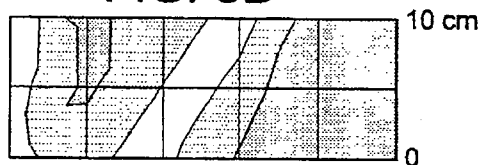


FIG. 8E

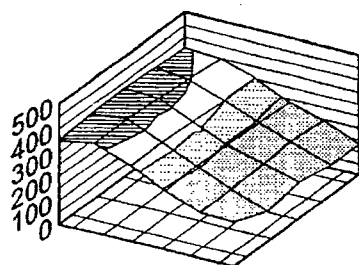
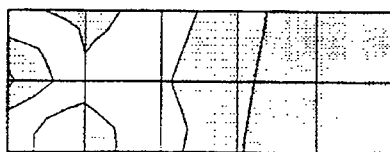


FIG. 8F



OILFIELD IN SITU HYDROCARBON UPGRADING PROCESS

This application claims benefit of provisional application No. 60/069,182 filed Dec. 11, '97

FIELD OF THE INVENTION

This invention relates to a catalytic in situ process for upgrading hydrocarbons in an underground reservoir. More particularly, it relates to a process in which a catalyst is placed along the horizontal segment of a horizontal production well operating in a toe-to-heel configuration, which enables carbon monoxide and/or hydrogen produced in the reservoir or injected into the reservoir with steam, to pass sequentially with reservoir oil over the catalyst, immediately prior to being produced.

BACKGROUND OF THE INVENTION

Large supplies of heavy oil (ca. 8 to 15 degrees API) and medium oil (ca. 15-25 API) exist throughout the world, most notably in Venezuela, Canada and the U.S.A. Significant deposits are also to be found in the North Sea, China and Romania. The composition of the crude oil barrel is inexorably moving towards this heavier material, but it is relatively uneconomic to produce. Without upgrading to produce an oil of lighter composition, i.e. containing more white oil distillates (gasoline, diesel, etc.), heavy oil has very limited potential, historically trading at around \$9.00 below the price of conventional oil. While surface upgrading technology (H-Oil, Vega-Combi or LC Fining processes) is possible, the payout time on the very large investment required is long (ca. ten years), which is discouraging to commercialization.

In situ oil upgrading has several advantages over conventional surface upgrading technologies. Because in situ upgrading (reaction occurring underground) can be implemented on a well-by-well basis, there is no need for large capital-intensive projects. Rather, the size of an in situ project for a particular field can be tailored to available production rates. Thus, in situ upgrading is practical even for those fields deemed too small to provide sufficient production for conventional surface upgrading processing. Additional advantages for in situ upgrading include the production of a more desirable and valuable product, ease in shipping and pipelining (minimum of 22 degree API gravity), and less demanding downstream processing (processable by a conventional refinery).

The requirements for an in situ upgrading process include: provision of a downhole bed of catalyst, achievement of appropriate high reaction temperatures and pressure at the catalyst bed, and mobilization of oil and co-reactants over the catalyst. Although the technologies to accomplish each of these tasks separately are known, their combination into a unified effective underground process has yet to be demonstrated in practice.

Because it is the most efficient method to achieve high temperatures in a reservoir without the direct application of heat, in situ combustion (ISC) is a promising oil recovery process to exploit in the development of an efficient and economical in situ upgrading process.

In-situ combustion processes are applied for the purpose of heating heavy or medium oil to mobilize it and drive it to an open production well for recovery. In general, the usual ISC technique used involves providing spaced apart vertical injection and production wells completed in a reservoir. Typically, an injection well will be located within a pattern

of surrounding production wells. Air, or other oxygen-containing gases are injected into the formation. The mixture of air or oxidizing gas and hydrocarbons is ignited, a combustion front is generated in the formation and the resulting combustion front is advanced outwardly toward the production wells. Or, alternately, a row of injection wells may feed air to a laterally extending combustion front which advances as a line drive toward a parallel row of production wells.

In both cases the operator seeks to establish an upright combustion front which provides good vertical sweep and advances generally horizontally through the reservoir with good lateral sweep. However the processes are not easy to operate and are characterized by various difficulties. One such difficulty arises from what is referred to as gravity segregation. The hot combustion gases tend to rise into the upper reaches of the reservoir. Being highly mobile, they tend to penetrate permeable streaks and rapidly advance preferentially through them. As a result they fail to uniformly carry out, over the cross-section of the reservoir, the functions of heating and driving oil towards the production wells. The resulting process efficiency therefore is often undesirably low. Typically the volumetric sweep efficiencies are less than 30%.

Weissman et al (Energy and Fuels. 1996, 10.883,889) have recently proposed a modified in situ combustion process using a vertical well production strategy, in which a catalyst bed is emplaced around the production well. They have reported the results of two ISC tests, from which they concluded that a heated bed of hydrocracker catalyst placed in the bottom section of an 1.8 m long, 0.1 m diameter combustion tube (a special thin-walled reactor to simulate reservoir conditions), was effective in converting carbon monoxide, produced at the combustion front, and water, into carbon dioxide and hydrogen, via the water gas shift reaction. Not only was 50% of the sulphur removed by hydrodesulfurization ("HDS"), but there were also decreases in the oil density and viscosity obtained by the catalytic reaction. However, there were two main problems foreseen with this process: (1) the high retention of oil in the catalyst bed/gravel-pack (a large, one-place volume, with a vertical producer well), would lead to severe coking of the catalyst; and 2) the need to operate in either a cyclic mode (backflow on the injector well), or with a severe gas override condition to provide heat to the catalyst bed. Both processes possibly require supplementary downhole heating, which is both expensive and risky. Also, very importantly, the extremely acidic process gases (carbon dioxide and sulfur dioxide) entering the vertical production well, in combination with a temperature of over 300 degrees Celsius, will cause severe corrosion to the vertical well, through which all production fluids must pass. In the case of deliberate combustion-gas override (which is used to achieve high temperatures at the vertical well), very poor reservoir sweep will be achieved and the possibility of oxygen breakthrough is increased, which could cause a serious explosion hazard. In the case that the proposed cyclic combustion process is used (again to achieve high temperatures at the vertical production well), the production rates will be at least halved because of the required air injection time in the same well. In summary, the two proposed catalytic in situ processes appear expensive and difficult to operate, and so are not felt to be feasible.

A new viscous oil recovery process has recently been developed which provides a substantial increase in reservoir sweep efficiency over that of the traditional ISC process. A combination of wells is used wherein the toes of horizontal production wells are the first segments to provide hydrocar-

bon production and to come into contact with the injected gases. Greaves and Turta, in U.S. Pat. No. 5,626,191, disclose such a well configuration, which they call the "toe-to-heel" oil displacement process. The patent applies to any process where gases are injected to reduce the viscosity of oil in an underground reservoir, and includes oxidizing gases for in situ combustion, steam injection, steam injection along with other gases, and hydrocarbon solvent gases.

Many oilfield operators are reluctant to apply the in situ combustion process because of historically poor performance when used in a traditional vertical well drive mode, and so an in situ upgrading process that uses steam would be more appealing. Since some heavy or medium gravity oil reserves are found in relatively deep and hot reservoirs, for example in the Orinoco Belt in Venezuela, high temperature steam can be utilized to provide the heat for an in situ upgrading process in some cases.

In summary of the prior art, it has been recognized as very desirable to achieve oil upgrading in an underground reservoir and the ISC process has been proposed as a possible heat source, but an effective process for implementing these steps has not yet been developed. The work underlying the present invention was undertaken to reach this objective. The present invention will now be described.

SUMMARY OF THE INVENTION

Considering the disclosure of U.S. Pat. No. 5,626,191 of Greaves and Turta that:

1. if a generally linear and laterally extending, upright combustion front is established and propagated high in an oil-containing reservoir; and
2. if an open production well is provided having a horizontal leg positioned low in the reservoir so that the well extends generally perpendicularly to and lies in the path of the front and has its furthest extremity ("toe") spaced from but adjacent to the injection sources; then
3. the production well will provide a low pressure sink and outlet that functions to induce the lateral sweep front to advance in a guided and controlled fashion, first intersecting the toe and then proceeding along the length of the horizontal leg - under these circumstances, the oil displacement front will remain generally stable and upright and be characterized by a relatively high reservoir sweep efficiency; and
4. the unreacted injectant gases and reaction gases will flow through the swept portion of the reservoir and through the vertical reaction front and react with the oil at the front. Streamlines of the gases will bend towards the horizontal leg, due to the downward flow gradient created by the action of the production well as a sink, but will also rise due to gravity phase segregation, resulting in a net vertical front advancing laterally without significant over-riding. In the case of steam injection, the condensed water and heated oil will, along with any gases present, likewise flow down to the low pressure sink. In the case of in situ combustion the gases will be combustion gases: carbon monoxide, carbon dioxide, sulphur dioxide and water vapor.

Now, in accordance with the present invention:

if an appropriate oil upgrading catalyst is placed along the horizontal leg of a production well arranged in toe-to-heel configuration, including any of within the leg, on the leg or in the reservoir around the leg; then

hot combustion gases from an ISC process, or steam from a steam injection process combined with injected

reducing gases, such as carbon monoxide or hydrogen, will react with the commingled oil over the catalyst at appropriate temperature and pressure and the oil will be substantially upgraded.

When compared in experimental runs with a conventional toe-to-heel ("TTH") in situ combustion process in accordance with the Greaves and Turta patent, without catalyst in the vicinity of the horizontal leg of the oil producing well, the present invention was found to be relatively characterized by:

- increased average API gravity of produced oil;
- reduced oil viscosity;
- reduced oxygen and carbon monoxide and increased carbon dioxide levels in the produced gas stream;
- extensive hydrodesulfurization of the oil; and
- extensive hydrodemetallization of the oil.

Additionally, the present process benefits from being a single pass catalytic process so that the reactant oil and gases continuously access fresh catalyst. The distributed catalyst along the horizontal well maintains high conversion activity by virtue of sequential catalyst exposure caused by the advancing movement of the combustion front from the toe to the heel of the horizontal well.

Therefore, in broad terms, the invention is a process for upgrading oil in an underground reservoir while the oil is recovered through a production well, comprising: providing an injection well for injecting a gaseous fluid into the reservoir to form an advancing, laterally extending displacement front operative to reduce the viscosity of reservoir oil; providing at least one open production well having a horizontal leg completed relatively low in the reservoir and positioned substantially perpendicular to and in the path of the advancing front; emplacing oil upgrading catalyst along the leg's length; injecting the gaseous fluid into the injection well and advancing the displacement front along the leg; and producing the production well to recover upgraded oil from the reservoir.

DESCRIPTION OF THE DRAWINGS

FIG. 1 is a perspective view schematically showing a sand pack with simulated vertical injection wells and a perpendicularly arranged, horizontal production well, said injection wells and production well being completed relatively high and low in the pack, respectively, as in the base case of the Greaves and Turta prior art, and reported below for Runs 971 and 972;

FIG. 2 is a perspective view schematically showing a sand pack with simulated vertical injection wells and a perpendicularly arranged, horizontal production well, said injection wells and production well being completed relatively high and low in the pack, respectively, as in FIG. 1, but with the placement of upgrading catalyst around the horizontal segment of the horizontal well, and reported below for Runs 975 and 976;

FIGS. 3a, 3b, 3c are top, side and end views of the test cell employed in demonstration of the present invention for the toe-to-heel process when operated in the catalytic upgrading mode in Runs 975 and 976;

FIG. 4 is a flow diagram showing the laboratory set-up, including the test cell of FIGS. 3a-3c, used to conduct the experimental runs reported on below;

FIGS. 5a and 5b show gas chromatographic spectra for Wolf Lake crude oil used in the test runs, and produced oil from the catalytic wet ISC Run 976 of the present invention, respectively;

FIG. 6 is a plan view showing a preferred field embodiment of the well layout;

FIG. 7 is a side cross-section taken along the line XII—XII of the well arrangement of FIG. 6; and

FIGS. 8a, 8c and 8e are horizontal thermal contour plots for three layers in the sand pack after 6 hours of operation during Run 7—FIGS. 8b, 8d and 8f are vertical cross-section thermal contour plots.

DESCRIPTION OF THE PREFERRED EMBODIMENT

The invention was developed in the course of carrying out an experimental investigation involving test runs carried out in a test cell or three dimensional physical model.

More particularly, a test cell 1, shown in FIGS. 3a, 3b and 3c was provided. The cell comprised a rectangular, closed, thin-walled stainless steel box 2. Dimension-wise, the box 2 formed a chamber 3 having dimensions 40×40×10 cm (total volume 16,000 c.c.). The thickness of each box wall was 4 millimeters. The chamber 3 was filled with a sand pack 4 consisting of a mixture of sand, clay, oil and water. The composition of the uniform mixture charged into the chamber 3 and other bed properties shown below in Table 1.

The porosity of the sand pack 4 was about 38.5% and the permeability was about 1.042 darcys.

The loaded cell box 2 was placed inside a larger aluminum box 5 and the space between them was filled with vermiculite powder insulation.

Sixty type K thermocouples 6, positioned at 6 cm intervals as shown in FIGS. 3a, 3b, 3c and 4, extended through the wall of the cell 1 into the sand pack 4, for measuring the three dimensional temperature distribution in the sand pack 4.

To compensate for heat losses, the cell 1 was wound with heating tape (not shown). This heat source was controlled manually, on demand, in response to the observed combustion peak temperature and adjacent well temperature values. The temperature at the wall of the cell was kept a few degrees Celsius less than the temperature inside the sand, close to the wall. In this way, the quasi-adiabatic character of the run was assured.

A cell heater 7 was embedded in the top section of the sand pack 4 at the air injection end, for raising the temperature in the region of the injection well 8 to ignition temperature.

Simulated air injection wells 8 were provided at the injection end of the cell 1. A simulated production well 9 was provided at the opposite or production end of the cell 1.

For Runs 975 and 976, a 0.25 inch diameter cylindrical catalyst bed was placed around the horizontal leg, whereas, for Runs 971 and 972, which constitute demonstrations of prior art for comparison purposes, the catalyst bed was omitted.

The positioning and vertical or horizontal disposition of the wells 8, 9 are shown schematically in FIGS. 1, 2 and 3a-3c for the four test runs reported on below. This well configuration is referred to as the direct line drive configuration. However, other well configurations are also contemplated, such as staggered line drive where the vertical injection wells are placed between the horizontal legs, or a horizontal injection well is placed relatively high in the reservoir to simulate the effect of a number of vertical injectors by having periodic perforations as a means to distribute the injectant gas. In the case that the reservoir heating is accomplished by injection of steam, the appropriate

location of the steam injectors will be reservoir-specific and may not be high in the reservoir.

As shown in FIG. 1 for non-catalytic Runs 971 and 972, a horizontal injection well 8 was placed relatively high in the cell, while the production well 9 was horizontal and placed relatively low in the test cell with its toe slightly displaced from the injection well. Non-catalytic Runs 971 and 972 were a demonstration of prior art (Greaves and Turta) and were conducted for comparison purposes only. Run 971 was a dry ISC process, and Run 972 was a wet ISC process. There was no catalyst present for these Runs.

As shown in FIGS. 2 and 3a-3c, for catalytic Runs 975 and 976, a horizontal injection well 8, positioned laterally across the sand pack 4, was provided. The injection well was located relatively high in the sand pack. The production well 9 was horizontal, elongated, positioned low in the sand pack and had its toe adjacent to but spaced from the injection well. The horizontal production well 9 was arranged to be generally perpendicular to a laterally extending combustion front developed at the injection source. However, the toe 10 of the production well was spaced horizontally away from a vertical projection of the injection well. An elongated ring of catalyst, 11, was placed around the horizontal well 9.

The oil upgrading catalyst employed in Runs 975 and 976 was a standard hydrotreating/HDS catalyst manufactured by Akzo Chemie Nederland bv. Amsterdam, and identified as Ketjenfine 742-1, 3AQ.

Each of the injection and production wells 8,9 were formed of perforated stainless steel tubing having a bore 4 mm in diameter. The tubing was covered with 100 gauge wire mesh (not shown) to exclude sand from entering the tubing bore.

The combustion cell 1 was integrated into a conventional laboratory system shown in FIG. 4. The major components of this system are now shortly described.

Air was supplied to the injection well 18 from a tank 19 through a line 20. The line 20 was sequentially connected with a gas dryer 21, mass flowmeter 22 and pressure gauge 23 before reaching the injection well 8. Nitrogen could be supplied to the injection well 8 from a tank 24 connected to line 20. Water could be supplied to the injection well 8 from a tank 27 by a pump 25 through line 26. Line 26 was connected with line 20 downstream of the pressure gauge 23. A temperature controller 28 controlled the ignition heater 7. The produced fluids passed through a line 30 connected with a separator 31. Gases separated from the produced fluid and passed out of the separator 31 through an overhead line 32 controlled by a back pressure regulator 33. The regulator 33 maintained a constant pressure in the test cell 1. The volume of the produced gas was measured by a wet test meter 34 connected to line 32. The liquid leaving the separator was collected in a cylinder 40.

Part of the produced gas was passed through an oxygen analyzer 36 and gas chromatograph 37. Temperature data from the thermocouples 6 was collected by a computer 38 and gas composition data was collected from the analyzer 36 and gas chromatograph 37 by an integrator 39.

TABLE 1

BED PROPERTIES				
Run Code	971	973	975	976
Bed Type	Uncon	Uncon	Uncon	Uncon
Sand Type	Silica. W50	Silica. W50	Silica. W50	Silica. W50

TABLE 1-continued

BED PROPERTIES				
Run Code	971	973	975	976
Sand wt %	97	97	97	97
Clay wt %	3	3	3	3
kaolinite				
Porosity %	38.5	38.5	38.5	38.5
Permeability (md)	1042	1042	1042	1042
S _{oi} %	76	76	76	76
S _{wi} %	17	17	17	17
S _{gi} %	7	7	7	7
Initial Temperature (Deg C.)	18	17	18	17

Air was injected at a rate of approximately 6.0 l/m. and ignition was initiated using the heater 7. The tests were typically continued for up to 11 hours for the dry ISC Runs 971, 975 and for 7.5 hours for the wet ISC Runs 972, 976. In the runs where water was added, its rate was 0.025 l/m. Details of the operating conditions are provided in Table 2.

TABLE 2

OPERATING CONDITIONS				
Run Code	971	972	975	976
Combustion Mode	Dry	Wet	Dry	Wet
Catalyst	no	no	yes	yes
Air flux (m ³ /m ² · hr)	9	9	9	9
Oxygen flux (m ³ /m ² · hr)	1.89	1.89	1.89	1.89
Air Injection Rate (l/min)	6	6	6	6
Water Air Ratio (m ³ /m ³)	0	0.0042	0	0.0042
Water injection rate (l/min)	0	0.025	0	0.025
Initial Temperature (Deg C.)	18	17	18	17
Operating pressure (psig)	25	25	25	25
Well Type	HI-HP	HI-HP	HI-HP	HI-HP
Configuration	Line Drive	Line Drive	Line Drive	Line Drive
Back pressure set point (psig)	24.4	24.3	24.5	24.4

Legend

HI=Horizontal Injector

HP=Horizontal Producer

Following completion of each run, an analysis of the cell sand pack 4 was undertaken to determine the volumetric sweep efficiency. The analysis comprised a physical removal of successive vertical layers of the sandpack at 3 cm intervals and determining the extent of the burned zone by measuring the oil and coke content. In this way the volumetric sweep of the burning front was determined postmortem and compared with that obtained from the peak temperature profiles during the run. The results of the four Runs are set forth in Table 3.

TABLE 3

SUMMARY OF RESULTS				
Run Code	971	972	975	976
Combustion Mode	Dry	Wet	Dry	Wet
Catalyst?	no	no	yes	yes
Overall period (hrs)	12.7	7.5	12.5	7.3
Pre-ignition period (hrs)	1.98	2.00	2.30	1.98
Air injection period (hrs)	10.7	5.5	10.2	5.3
Dry phase period (hrs)	10.7	2.4	10.2	2.6
Wet phase period (hrs)	0	3.1	0	2.7
Peak temp (dry phase) (deg C.)	621	625	629	627
Stabilized temp (dry phase) (deg C.)	452	455	455	451
Peak temp (wet phase) (deg C.)	N/A	477	N/A	468
Stabilized temp (wet phase) (deg C.)	N/A	393	N/A	402
CO ₂ % (dry stabilized)	14.3	14.2	16.5	16.5
CO % (dry stabilized)	4.0	4.0	2.4	2.3
O ₂ % (dry stabilized)	1.10	1.18	0.85	0.93
CO ₂ % (wet stabilized)	N/A	13.9	N/A	17.1
CO % (wet stabilized)	N/A	3.5	N/A	0.3
O ₂ % (wet stabilized)	N/A	2.3	N/A	1.6
H ₂ % (calculated for 975 & 976)	N/A	N/A	1.9	5.8
CO/CO + CO ₂	0.220	0.200	0.130	0.017
H/C	0.73	0.71	0.44	0.33
Air to Fuel requirements (Sm 3/kg)	9.485	9.544	9.457	9.810
O ₂ to fuel requirements (Sm 3/kg)	2.00	2.00	2.00	2.06
Fuel burned (kg)	0.384	0.186	0.371	0.181
Fuel burned (% of OOIP)	9.10	4.40	8.74	4.27
Oxygen utilization % (Average)	94.8	89.0	96.0	92.3
Volumetric sweep efficiency %	40.7	43.0	39.0	38.7
Fuel combustion (kg/m ³)	65	30	65	32
Air Oil ratio (m ³ /m ³)	1328	744	1428	738
Water Air ratio (m ³ /m ³)	0	0.0042	0	0.0042
Oil recovery % of OOIP	67.9	62.3	60.4	53.2
Water recovery % of OOIP	91.3	80.4	71.1	69.8
Combustion front velocity (m/hr)	0.016	0.024	0.015	0.022

The produced gas analyses provide support for occurrence of the water gas shift reaction in the catalyst zone. The reaction is: $\text{CO} + \text{H}_2\text{O} = \text{CO}_2 + \text{H}_2$. Comparing the non-catalytic and catalytic dry ISC Runs, 971 and 975 respectively, the CO produced gas is 40% lower for the catalytic case (2.4% vs 4.0%).

Comparing the produced CO for the wet combustion cases, Runs 972 and 976, the CO level is 91% lower when catalyst is present (0.31% vs 3.50%).

The CO₂ levels are higher in the two catalyst Runs 975 and 976, compared with the corresponding non-catalytic Runs 971 and 972, which provides further support for the water gas shift reaction as a primary source of hydrogen in catalytic in situ upgrading.

The differences in recovery of the original water in place can be used to calculate the amount of hydrogen produced and consumed during in situ upgrading reactions; the result is 1.91% of the total produced gas phase for Run 975 dry catalytic ISC, and 5.8% for wet catalytic ISC Run 976.

The results described above make it clear that any catalyst that has water gas shift activity would be beneficial and could be employed by itself or in any proportion in admixture with the hydrotreating/HDS catalyst used in Runs 975 and 976 or other such catalyst.

Since the water gas shift reaction produces the hydrogen required for oil upgrading, the process can be carried out by injecting high temperature steam and carbon monoxide. A carbon monoxide source, for example, oxygen-starved combustion of natural gas, will produce a gas elevated in CO which can be injected into the reservoir. In this way the key ingredients for effective in situ upgrading will be provided: these are heat, hydrogen and active catalysts.

Also to be noted as a benefit of catalytic ISC is the lower level of produced oxygen. Since each pair of non-catalytic and catalytic Runs were conducted under the same conditions, the oxygen reduction can be attributed to the presence of catalyst.

The analyses of produced oil are presented in Tables 4 and 5 for API gravity, density and viscosity at each half-hour interval.

The prior art toe-to-heel ISC process of Greaves and Turta provides considerable thermal upgrading as measured by the three aforementioned parameters (Runs 971 and 972), but still fall very short of the performance of the catalytic Runs 975 and 976 of the present invention. The average results are summarized in Table 6. Wet catalytic ISC improved the oil gravity from 11.0 API to 20.7 API and reduced the viscosity from 100,000 cps to 46 cps. Therefore the upgraded oil at a viscosity of 46 cps will be easily pipelined without the need for a diluent. Since diluent light hydrocarbons are expensive and in short supply this is a valuable benefit of the present invention.

TABLE 4

DRY NORMAL AND CATALYTIC						
Run 971 (Dry Normal)				Run 975 (Dry Catalytic)		
Time	API	Density	Viscosity	API	Density	Viscosity
0.5	11.0	0.993	100000	11.0	0.993	100000
1	11.0	0.993	100000	11.3	0.991	97780
1.5	11.0	0.993	100000	14.2	0.971	8220
2	11.1	0.992	98873	14.6	0.969	7830
2.5	12.4	0.983	20234	20.6	0.930	40
3	12.8	0.981	14060	20.5	0.931	43
3.5	15.3	0.964	7435	19.8	0.935	62
4	14.8	0.967	7675	19.5	0.937	68

TABLE 4-continued

DRY NORMAL AND CATALYTIC						
Run 971 (Dry Normal)				Run 975 (Dry Catalytic)		
Time	API	Density	Viscosity	API	Density	Viscosity
4.5	14.5	0.969	8020	19.3	0.938	74
5	14.1	0.972	8430	19.2	0.939	82
5.5	14.3	0.971	8160	18.9	0.941	97
6	14.0	0.973	8570	18.6	0.943	104
6.5	13.8	0.974	9010	18.4	0.944	111
7	13.7	0.945	9035	18.3	0.945	117
7.5	13.9	0.973	8660	18.2	0.945	123
8	14.0	0.973	8550	18.5	0.943	106
8.5	13.8	0.974	8990	18.0	0.946	133
9	13.6	0.975	9050	18.3	0.945	118
9.5	13.2	0.978	9780	18.4	0.944	110
10	13.4	0.977	9580	18.2	0.945	123
10.5	13.5	0.976	9440	18.3	0.945	118
11	13.3	0.977	9630	18.1	0.946	129
11.5	13.4	0.977	9560	18.0	0.946	132
12	13.1	0.979	9820	18.3	0.945	118
12.5	13.2	0.978	9770	18.4	0.944	109
Average (3.5-12.5 hrs)	13.8	0.972	8903	18.7	0.948	101

TABLE 5

WET NORMAL AND CATALYTIC						
Run 971 (Dry Normal)				Run 975 (Dry Catalytic)		
Time	API	Density	Viscosity	API	Density	Viscosity
0.5	11.0	0.993	100000	11.0	0.993	100000
1	11.0	0.993	100000	11.7	0.988	95760
1.5	11.0	0.993	100000	13.4	0.977	10043
2	11.2	0.967	99020	15.1	0.965	6320
2.5	14.8	0.971	7690	19.8	0.935	65
3	14.2	0.975	8210	20.4	0.932	46
3.5	13.7	0.976	9015	19.7	0.936	63
4	13.5	0.974	9460	19.6	0.936	65
4.5	13.8	0.977	9000	19.4	0.938	72
5	13.4	0.977	9560	22.2	0.930	24
5.5	13.2	0.978	9760	20.7	0.921	37
6	12.5	0.983	10170	21.4	0.925	31
6.5	13.0	0.979	9900	20.7	0.930	37
7	12.9	0.980	9960	21.0	0.928	33
7.5	12.8	0.981	10040	21.3	0.926	32
Average (2.5-7.5 hrs)	13.4	0.980	9342	20.6	0.931	46

TABLE 6

SUMMARY OF UPGRADING RESULTS (AVERAGES)				
Run #	Condition	API Gravity	Density g/cc	Viscosity mPa · s
Base	no ISC	11.0	0.993	100,000
971	Dry Normal	13.8	0.972	8,903
975	Dry Catalytic	18.7	0.948	101
972	Wet Normal	13.4	0.980	9,342
976	Wet Catalytic	20.7	0.931	46

Further important upgrading benefits are demonstrated in Table 7, where XT004466 is clean dry Wolf Lake crude oil which was used in the four test Runs 971, 972, 975 and 976, and XT004467 is produced oil from the wet catalytic Run 976 of the present invention.

An extensive desulfurization and demetalization of the base oil was achieved in the catalytic Run 976 of the present invention. Sulfur was reduced 88% from 43,400 ppm to

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5,100 ppm; nickel 96% from 73 ppm to 3 ppm and vanadium 96% from 195 ppm to 8 ppm. Other metals, such as iron and molybdenum were also partially removed in the catalytic process. It should be noted that the increase in silicon is not a consequence of the presence of catalyst: all high temperature steam processes give rise to elevated silicon levels.

TABLE 7

OIL SULFUR AND METAL ANALYSIS (by ICP, mg/kg)		
Sample ID	XT004466 (10 API)	XT004467 (20.7 API)
Customer ref:	Base Wolf Lake oil	Run 976 product
Silver	<1	<1
Aluminum	<1	<1
Boron	2	3
Barium	<1	<1
Calcium	2	2
Chromium	<1	<1
Copper	<1	<1
Iron	5	<1
Potassium	<8	<8
Magnesium	1	<1
Manganese	<1	<1
Molybdenum	7	3
Sodium	<6	<6
Nickel	73	3
Phosphorus	<2	<2
Lead	<2	<2
Sulphur	43400	5100
Silicon	1	69
Tin	<2	<2
Titanium	1	<1
Vanadium	195	8
Zinc	2	5

FIG. 5 shows gas chromatographic analyses of samples XT 004466 Wolf Lake crude oil and Run 976 wet catalytic ISC product. Very extensive oil upgrading is apparent from the large decrease in heavy components observed in the catalytic Run.

The wet combustion test of Run 976 demonstrated the preferred form of the invention. Either moderate wet combustion or superwet combustion may be applied. However, in oil reservoirs where water injectivity is too low, the catalytic dry combustion process may be applied as well. Test of NCC Type Catalyst

Run 986 was conducted using NCC catalyst placed around the horizontal leg of the producer for the purpose of comparison with an otherwise identical non-catalytic Run 985.

The original test cell was modified to have 6-band heaters and computer control to provide a better approach to adiabatic conditions.

The catalytic Run 986 used the catalyst FCC-RESOC-1 BU, a rare earth aluminosilicate supplied by Grace Davison, and having the following physical characteristics.

Composition	42% Al ₂ O ₃ , 1.0% Rare Earth oxide, 0.2% Na ₂ O
Surface area (square meters/gm)	300
Bulk density (g/ml)	0.7
Average particle size (microns)	72

Results showed that the Run 986 with NCC catalyst produced Wolf Lake oil (11 API) of 21.0 degrees API, which was 7 degrees API higher than the thermally cracked oil in the absence of catalyst in Run 985.

The effect of vertical heterogeneity of the reservoir on fluid channeling was tested in a specially-packed cell in Run

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7. Three layers of sand were packed sequentially using fine, coarse and fine-grained sands to see whether air would advance ahead of the vertical combustion front in the high-permeability central layer. Table 8 gives the details of the stratified model. FIGS. 8a-8f shows the results in terms of thermal contours. The vertical axis represents temperature in all cases. Lowest temperatures are shown in dark color. The combustion front remained substantially vertical, with no preferred advancement into the central zone. The explanation may be that the vertical drainage of the hot cracked oil provides a "self-healing" phenomenon where air advancement into the central high permeability streak is blocked by draining oil. This demonstrates that the process of the present invention has a major advantage over processes of the prior art in which both the injected air and produced fluids flow substantially horizontally between vertical wells and fingering of air into high permeability layers causes early oxygen breakthrough and safety hazards. Layers of varying permeability are a very common feature of clastic reservoirs and often prohibits the use of traditional in situ combustion as an oil recovery process. The present invention removes this limitation.

TABLE 8

RUN 7 DRY IN SITU COMBUSTION IN A STRATIFIED MODEL; CLAIR OIL, 19.8 API, 200 CPS AMBIENT		
Layer	Sand Grain Size	Permeability MD
Top	fine	616
Middle	coarse	3000
Bottom	fine	616

In the preferred field embodiment of the invention, the direct line-drive application illustrated in FIGS. 6 and 7, a reservoir 100 is characterized by a downward dip and lateral strike. A row 101 of vertical air-water injection wells 102 is completed high in the reservoir 100 along the strike. At least two rows 103, 104 of production wells 105, 106 having generally horizontal legs 107, are completed low in the reservoir and down dip from the injection wells, with their toes 108 closest to the injection wells 102. The toes 108 of the row 103 of production wells 105 are spaced down dip from a vertical projection of the injection wells 102. Catalyst particles are emplaced along the horizontal well by a well-known operation called "gravel packing". The second row 104 of production wells 106 is spaced down dip from the first row 103, and is similarly gravel packed. Generally, the distance between wells, within a row, is considerably lower than the distance between adjacent rows. In the first phase of the process, a generally linear combustion front is generated in the reservoir 100 by injecting air or air-water through every second well 102. Preferably a generally linear lateral combustion front is developed by initiating combustion at every second well and advancing these fronts laterally until the other wells are intercepted by the combustion front and by keeping the horizontal production wells closed. Then, air is injected through all the wells 102 in order to link these separate fronts to form a single front. Only during this initiation phase of the field exploitation process, and only once in the lifetime of a producing reservoir, is non-upgraded oil produced. The front is then propagated by injecting air and water down dip toward the first row 103 of production wells 105. The horizontal legs of the production wells 105 are generally perpendicular to the front. The production wells 105 are open during this step, to create a

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low pressure sink to induce the front to advance along their horizontal legs 107 and to provide an outlet for the heated oil. When the front approaches the heel 109 of each production well 105, the well is closed in. The horizontal legs 106 (107) of the closed-in wells 105 are then filled with cement. The wells 105 are then perforated high in the reservoir 100 and converted to air-water injection, thereby continuing the propagation of a combustion front toward the second row 104 of production wells 106. Preferably, the first row 101 of injection wells is converted to water injection for scavenging heat in the burnt out zone and bringing it ahead of the combustion zone. This process is repeated as the front progresses through the various rows of production wells. By the practice of this process, a guided combustion front is caused to move through the reservoir with good volumetric sweep efficiency, and the production of upgraded oil.

The embodiments of the invention in which an exclusive property or privilege is claimed are defined as follows:

1. A process for upgrading hydrocarbons in-situ in an underground reservoir having hydrocarbons, comprising the steps of:

- (a) providing at least one injection well for injecting an oxidizing gas into the underground reservoir;
- (b) providing at least one production well having a substantially horizontal leg and a substantially vertical production well connected thereto, wherein the substantially horizontal leg extends toward the injection well, the horizontal leg having a heel portion in the vicinity of its connection to the vertical production well and a toe portion at the opposite end of the horizontal leg, wherein the toe portion is closer to the injection well than the heel portion;
- (c) providing an oil upgrading catalyst between the toe portion and the heel portion substantially coextensive with at least a portion of the horizontal leg;
- (d) injecting the oxidizing gas through the injection well for in-situ combustion, so that combustion gases are produced;
- (e) thermally upgrading the hydrocarbons in a first in-situ upgrading phase of the process, wherein the combustion gases initially contact the hydrocarbons in the vicinity of the toe portion of the horizontal leg;
- (f) catalytically upgrading at least a portion of the hydrocarbon thermally upgraded in step (e) in a second in-situ upgrading phase of the process, wherein at least a portion of the hydrocarbons thermally upgraded in step (e) and at least a portion of the combustion gases initially contact the oil upgrading catalyst in the vicinity of the toe portion of the horizontal leg; and
- (g) progressively thermally and catalytically upgrading hydrocarbons, wherein
 - (i) the combustion gases progressively advance as a front, substantially perpendicular to the horizontal leg, in a direction from the toe portion to the heel portion and
 - (ii) the oil upgrading catalyst is progressively consumed substantially in a direction from the toe portion to the heel portion of the horizontal leg.

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2. The process of claim 1 wherein the oil upgrading catalyst is provided in packing around the horizontal leg of the production well.

3. The process of claim 1 wherein the horizontal leg of the production well is coated with the oil upgrading catalyst.

4. The process of claim 1 wherein the oil upgrading catalyst is provided in packing inside the horizontal leg of the production well.

5. The process of claim 1 wherein the oil upgrading catalyst comprises a hydrosulfurizing catalyst.

6. The process of claim 1 wherein a water-gas shift catalyst is used in combination with the oil upgrading catalyst.

7. The process of claim 1 wherein the oxidizing gas comprises air.

8. The process of claim 1 wherein a reducing gas is injected through the injection well.

9. The process of claim 8 wherein the reducing gas is selected from carbon monoxide, hydrogen and a combination thereof.

10. The process of claim 1 wherein a substantially linear array of substantially vertical injection wells is used for injecting oxidizing gas.

11. The process of claim 10 wherein the reservoir extends downwardly at an angle to have a dip and a strike, the injection wells extend generally along the strike and the horizontal leg of the production well extends generally along the dip.

12. The process of claim 10 wherein the reservoir extends downwardly at an angle to have a dip and a strike, a plurality of production wells, each connected to horizontal legs, are provided in at least two spaced apart rows parallel with the array of injection wells, and the rows of injection wells and production wells extend generally along the strike and the horizontal legs of the production wells extend generally along the dip.

13. The process of claim 12 wherein the wells are arranged in a staggered line.

14. The process of claim 12 wherein the wells are arranged in a direct line drive configuration.

15. The process of claim 12, further comprising the steps of:

- (h) closing each production well in the first row as the combustion front approaches the heel of its respective horizontal leg;
- (i) filling the horizontal legs of the closed production wells in the first row with cement;
- (j) re-completing the wells relatively high in the reservoir and converting them to injection wells for injecting oxidizing gas; and
- (k) repeating steps (d) through (g).

16. The process of claim 1 wherein the injection well is a horizontal well having a horizontal portion perpendicular to the horizontal leg of the production well.

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[54] **IN-SITU COMBUSTION METHOD FOR
RECOVERY OF HEAVY OIL UTILIZING
OXYGEN AND CARBON DIOXIDE AS
INITIAL OXIDANT**

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[51] Int. Cl.³ F21B 43/243

[52] U.S. Cl. 166/261

[58] Field of Search 166/256, 261, 272, 274

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[57] **ABSTRACT**

An in-situ combustion method for recovering viscous oil from a subterranean, viscous oil-containing formation comprising injecting a mixture of essentially pure oxygen and carbon dioxide into the formation to initiate an in-situ combustion operation followed by injecting essentially pure oxygen.

5 Claims, No Drawings

IN-SITU COMBUSTION METHOD FOR RECOVERY OF HEAVY OIL UTILIZING OXYGEN AND CARBON DIOXIDE AS INITIAL OXIDANT

BACKGROUND OF THE INVENTION

1. Field of the Invention

This invention pertains to the recovery of oil from a subterranean, viscous oil-containing formation utilizing an improved in-situ combustion process.

2. Background of the Invention

In-situ combustion is a common method for recovering viscous crudes or tar sands. The use of high purity oxygen in place of air significantly improves the performance of the in-situ combustion process. The injection of oxygen into a wellbore, however, presents significant hazards and requires safety precautions. Previous work in this regard includes the injection of O₂ through a bottom water zone, as disclosed in U.S. Pat. No. 3,208,519, and the initiation of combustion with air followed by oxygen as disclosed in an article by G. Pusch, Erdol und Kohle-Erdgas-Petrochemie combined with Brennstoff-Chemie, Vol. 30, No. 1, Jan. 1977, pp. 13-25. All these methods use air to establish gas flow. However, it has been found that injection of air increases the viscosity of the oil by 100 times when the oil is contacted by air for two days at 210° F. This increase in viscosity is detrimental to the recovery process. In addition, the inert gaseous nitrogen in the air injected tends to reduce the effective permeability for oil in the reservoir.

My invention proposes a method to initiate the in-situ combustion operation initially using a combustion supporting gas comprising a mixture of essentially pure oxygen and carbon dioxide followed by the use of essentially pure oxygen that eliminates the problem of increasing the viscosity of the oil in the formation using conventional combustion supporting gases such as air, air enriched with oxygen, or oxygen.

SUMMARY OF THE INVENTION

The invention is a method for recovering oil from a subterranean, viscous oil-containing formation penetrated by at least one injection well and a spaced apart production well comprising initiating in-situ combustion by injecting a mixture of essentially pure oxygen and carbon dioxide into the injection well followed by injecting essentially pure oxygen into the formation to support in-situ combustion either immediately after the initiation of combustion or after the combustion front has advanced away from the injection well a distance of at least 30 feet. The amount of carbon dioxide mixed with oxygen for initiation of in-situ combustion is not more than 80%. The use of an oxygen/carbon dioxide mixture to initiate in-situ combustion does not promote degradation in oil viscosity due to oxidation.

DESCRIPTION OF THE PREFERRED EMBODIMENT

In one embodiment of my invention, an in-situ combustion front is established in a subterranean, viscous oil-containing formation such as tar sand deposits by injecting a combustion-supporting gas comprising essentially pure oxygen and carbon dioxide. The oxygen/carbon dioxide mixture is introduced into the formation via at least one injection well to establish an in-situ combustion front and oil is produced from the formation via a spaced apart production well. The amount of

carbon dioxide mixed with the oxygen must not be more than 80% so as not to interfere with the in-situ combustion process. The amount of carbon dioxide may be substantially less than 80%, depending upon the experience of operating personnel in handling high purity oxygen. Once an in-situ combustion front is initiated, or preferably after the combustion front has advanced away from the injection well a distance of at least 30 feet, the mixture of O₂/CO₂ is terminated and essentially pure oxygen is injected into the injection well to support combustion. In a preferred embodiment, after in-situ combustion has been initiated, or preferably after the combustion front has advanced away from the injection well a distance of at least 30 feet, the amount of carbon dioxide injected into the formation along with oxygen is gradually decreased at a controlled rate until the combustion-supporting gas comprises essentially pure oxygen.

The use of a mixture of oxygen and carbon dioxide as the combustion-supporting gas to initiate in-situ combustion does not promote degradation in oil viscosity due to oxidation as is the case with mixtures of oxygen and nitrogen in conventional in-situ combustion processes. In the present process, any increase in oil viscosity due to oxidation is more than offset by a reduction in viscosity due to carbon dioxide dissolution. For example, an Athabasca bitumen with a viscosity of 50,000 cp at 104° F. will have a reduction in viscosity by 100 times, when saturated with carbon dioxide at 600 psia (see Jacobs, F. A., et al., J. Can. Pet. Tech., Oct.-Dec., 1980, pages 46-50). In the latter example, it is disclosed that it requires only 200 scf of carbon dioxide to saturate a barrel of oil at 600 psia. Assuming the oil saturation is 1000 bbls/ac-ft, it requires only 0.2×10⁶ scf/ac-ft of carbon dioxide to saturate the oil. After in-situ combustion has been initiated, there is a sufficient amount of carbon dioxide generated in-situ to saturate the oil in the formation so there is no need to continuously inject carbon dioxide during the combustion process. It is noted that the dissolution of the carbon dioxide in the oil reduces the free gas in the reservoir and increases effective oil permeability. In addition, carbon dioxide has a nice fire-extinguishing characteristic which can be conveniently applied in the case of an accidental well-bore ignition.

The oxygen and carbon dioxide may both be stored in liquid form near the injection well or wells. Both materials may be more conveniently pumped in liquid form from separate storage tanks into a vaporizer and then injected into the injection well. The composition of the oxygen/carbon dioxide mixture supplied to the injection well is controlled by sensing and controlling the flow rates of the individual oxygen and carbon dioxide streams by means of a flow controller.

What is claimed is:

1. A method for recovering oil from a subterranean, viscous oil-containing formation penetrated by at least one injection well and a spaced apart production well comprising:

(a) initiating an in-situ combustion front in the formation by injecting a combustion-supporting gas comprising a mixture of essentially pure oxygen and carbon dioxide into the injection well and continuing injection of said combustion-supporting gas until said combustion front has advanced a predetermined distance from the injection well, said injected carbon dioxide dissolving

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in the in place oil thereby reducing its viscosity and increasing effective oil permeability;

(b) thereafter terminating injection of the mixture of essentially pure oxygen and carbon dioxide and injecting essentially pure oxygen into the injection well to support in-situ combustion; and

(c) producing oil from the formation via said production well.

2. The method of claim 1 wherein the combustion-supporting gas in step (a) comprises not more than 80% carbon dioxide.

3. The method of claim 1 wherein injection of the mixture of essentially pure oxygen and carbon dioxide is

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continued during step (a) until the combustion front has advanced away from the injection well a distance of at least 30 feet.

4. The method of claim 1 further comprising gradually decreasing the amount of carbon dioxide in said combustion-supporting gas following step (a) until the gas injected comprises essentially pure oxygen.

5. The method of claim 4 wherein the amount of carbon dioxide is gradually decreased when the combustion front has advanced away from the injection well a distance of at least 30 feet.

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United States Patent [19]

Pusch et al.

[11] 4,042,026

[45] Aug. 16, 1977

[54] METHOD FOR INITIATING AN IN-SITU RECOVERY PROCESS BY THE INTRODUCTION OF OXYGEN

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[52] U.S. Cl. 166/258; 166/251; 166/261; 166/262

[58] Field of Search 166/261, 256, 302, 258, 166/303, 251, 262

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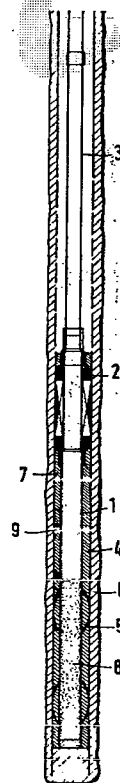
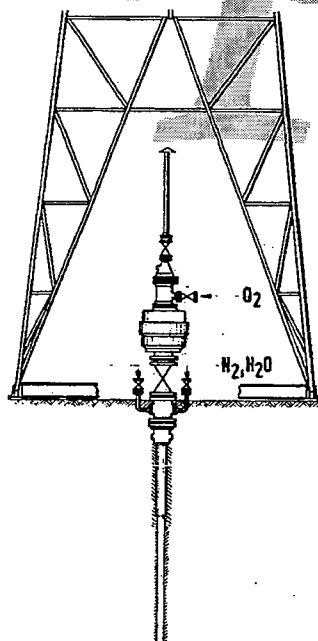
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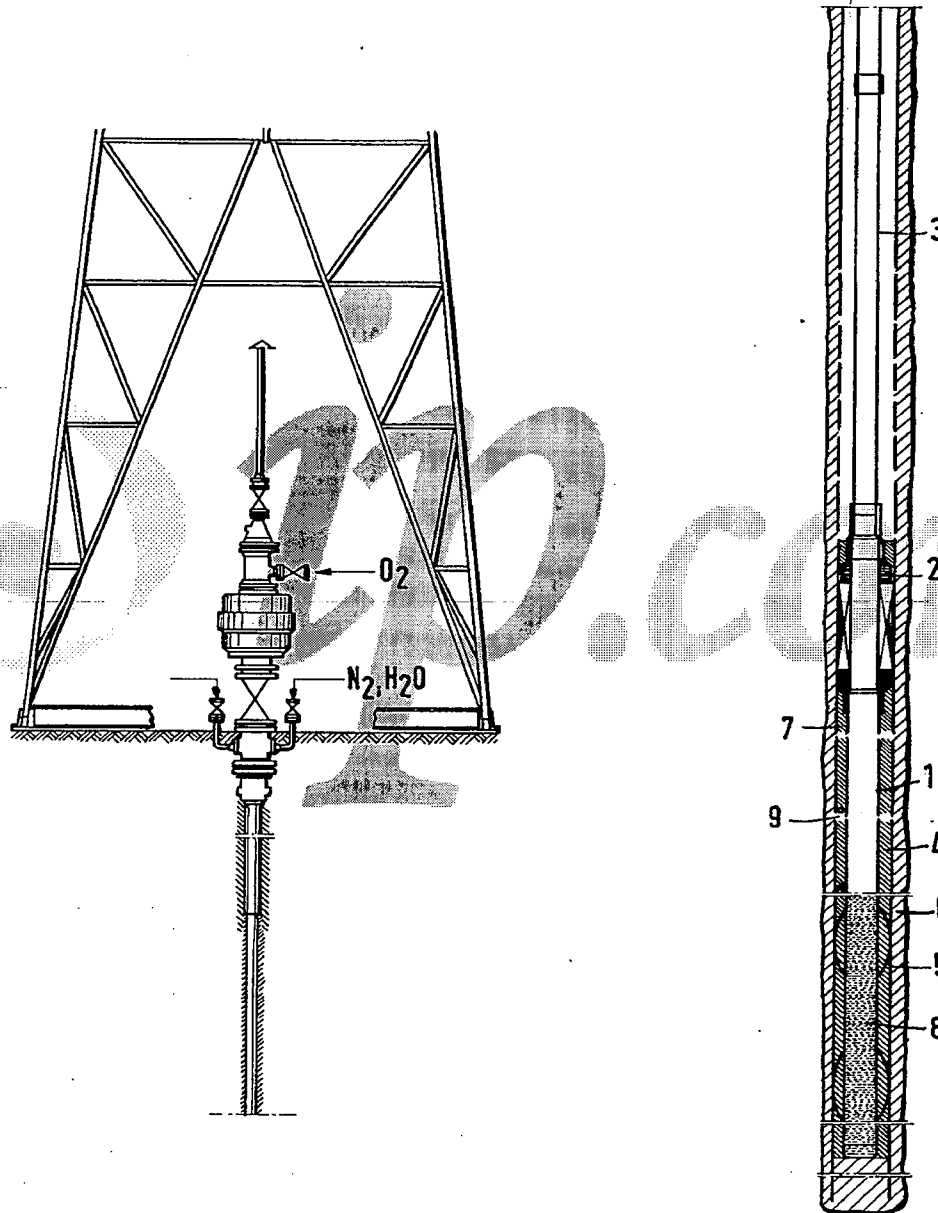
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[57] ABSTRACT

A method for starting a process to recover energy raw materials from a subterranean formation whereby igniters are injected into the upper region of the formation and inert gas is injected into the lower region of the formation, and thereafter an oxygen-containing gas is injected at a predetermined oxygen concentration and rate to initiate combustion, followed by increasing the oxygen concentration and/or rate of the injected gas to a maximum value.

15 Claims, 1 Drawing Figure





METHOD FOR INITIATING AN IN-SITU RECOVERY PROCESS BY THE INTRODUCTION OF OXYGEN

BACKGROUND OF THE INVENTION

This invention relates to a method for initiating an in-situ recovery process or for starting the operation of the process to recover energy raw materials from a subterranean formation by the introduction of oxygen into the formation.

Since the invention of the underground combustion method for petroleum recovery by F. A. Howard in 1923, a number of methods have been developed, the object of which is the production of heat within the reservoir, especially of sufficient heat, by means of partial combustion of oil residues in a petroleum reservoir to enable recovery of the remaining oil. The most important processes contributing to petroleum displacement are viscosity reduction by means of heat, distillation and cracking of the oil and of the higher boiling components, sweeping out of the oil with hot water and extraction of the oil by means of miscible products. Such a method is specified, for example, in U.S. Pat. No. 3,026,935. Specific modifications of this method require a high oxygen partial pressure in order to bring about miscibility of the carbon dioxide formed during combustion. A high oxygen partial pressure can generally only be obtained by enriching the combustion-supporting gas with oxygen. Oxygen is known to be a gas which reacts readily with almost all substances. The amount of combustion heat released for example in a reaction between oxygen and organic fuels is considerable. On average it amounts to 3000 kcal per kg oxygen.

One of the disadvantages of the use of oxygen is its hazardous nature that could lead to uncontrolled reactions or explosions. Because of the hazardous nature of pure oxygen in reacting with other materials much work has been done to reduce this danger. In addition to the question of reaction of oxygen with various materials the dynamics of compressible fluids is also an important factor in determining what hazard exists when a material is reacted with oxygen.

Great importance is accordingly attached to the structure of the spaces in which the oxygen is flowing. Should said spaces possess a large inner surface in relation to the volume then the danger of an explosion when a fuel and oxygen are reacted is greatly reduced. Consequently the reaction of oxygen with oil contained in the pores of the reservoir rocks poses relatively few problems. However, given certain geometric proportions of the spaces through which the oxygen flows, local temperature peaks can occur, which, although not in accordance with the laws of the dynamics of compressible fluid, cause ignition of the material (steel, plastic, wood etc.).

Finally it is known from experience in autogenous gas cutting that not only the nature of the material but also the composition of the gas used has an influence on the material's cutting quality. With an oxygen content of less than 95%, steel can still be ignited but combustion is not self-sustaining. These ratios apply to atmospheric pressure. However there exists no practical experience with regard to high pressures as found in deep petroleum reservoirs.

If one proceeds from the assumption that the operation of oxygen plants above ground can be considered relatively safe and that the reaction of the oxygen with

the oil in the reservoir can be controlled, then it follows that the most dangerous point along the oxygen's flow-path is the borehole. The operating conditions in a petroleum borehole are such that when high percentage oxygen is introduced there is a great danger of an explosion in the borehole. Neither is the borehole equipment made from deflagration-proof material (copper, Inconel) nor is the condition of the equipment, due to contact with corrosive, erosive and organic agents, such that the danger is lessened.

It is therefore the objective of this invention to eliminate these risks or at least reduce them to an acceptable level within the framework of conventional equipment used in boreholes for the recovery of energy raw materials such as petroleum hydrocarbons.

BRIEF DESCRIPTION OF THE DRAWING

The accompanying drawing illustrates the method used in the invention.

DESCRIPTION OF THE PREFERRED EMBODIMENT

In order to achieve this objective, a method for starting the operation of a process for subterranean recovery of energy raw materials by introducing oxygen into the penetrated reservoir was developed, characterized in that, igniters known per se are injected into the upper region of the reservoir, that simultaneously an inert gas is injected into the lower region of the reservoir to prevent the igniters penetrating into this region, that subsequently a gas with a predetermined oxygen concentration and a rate of injection is introduced until a corresponding increase in temperature indicates that ignition has taken place and a combustion front is formed, that injection of the gas is continued at the same rate until the combustion front is at a predetermined distance from the injection borehole, whereafter the rate of injection and/or oxygen concentration is increased to a predetermined maximum rate or end concentration, that the oxygen is injected into the reservoir through at least one radially arranged outlet opening with a pressure ratio of flow-in pressure to discharge pressure at the outlet opening of from 1.2 to 2.5 and that simultaneously water is injected into the upper region of the reservoir.

An advantage of this method is that the injection of the igniters and the gases into the reservoir by means of two vertically unconnected regions avoids oxygen and residual oil from the reservoir coming into contact with igniters in the borehole, thereby eliminating the dangerous phase during the injection of oxygen.

A more complete understanding of the performance and advantages of the invention may be had by referring to the drawing. The drawing illustrates a cross-sectional view of a borehole traversing the subterranean reservoir containing the energy raw material.

Packer 2 with Liner 1, made of high-grade steel, is set in the casing and cemented in the borehole. Prepared cement 4, mixed with suitable setting inhibitors, is previously pumped into the borehole up to a specific level. Once packer 2 has been set at the correct height the superfluous cement 4 is circulated off. An injection pipe 3 is screwed into packer 2. This string has a flexible part to equalize tensions resulting from changes in temperature and pressure. Only dry gases are injected through pipe 3. The injection gas is passed from the borehole into the reservoir via openings 9 which have been subsequently perforated through liner 1, the first cement

using 4, casing 5 and the second cement casing 6. The number of openings and their cross-sectional area is such that, at given specific injection rates and injection pressures, "critical flow conditions" exist within the outlet openings.

It was found, surprisingly, that given said flow conditions and conditions similar to them, neither combustion of the metal nor an explosion due to organic residues occurred. The critical flow conditions are defined such that at the appropriate temperature the gas is expelled at the velocity of sound. At this point it draws heat from the surrounding area to such an amount that rapid cooling occurs, thus preventing the ignition temperature of steel ($\sim 1100^\circ \text{C}$) and of organic residues ($> 150^\circ \text{C}$) being reached. The velocity of sound of the gas is reached with the pressure ratio prior to, and behind the outlet opening reaches 1.89. The pressure gradient of the borehole wall is generally determined by means of the injection pressure, the injection rate, the number of perforation openings plus their cross-sectional area and the back pressure in the rock (reservoir pressure and friction loss in the rock). Only two of said characteristic magnitudes are independently variable, the remainder being fixed.

If one of the two pressures is given and the other is variable, and in addition the maximum injection rate is fixed, then the outlet cross-sectional area required to obtain critical flow conditions can be calculated.

$$F = \frac{q}{v [1 - (\gamma - 1)/2]^{1/\gamma - 1}}$$

$$v_{\max} = a_s = \{[2 \gamma / (\gamma + 1)] g R' T\}^{1/2}$$

F = outflow cross-sectional area (m^2)

q = gas flow rate in the pipe (m^3/s)

v = flow velocity in outlet opening (m/s)

T = temperature of gas in the pipe (K)

a_s = Laval velocity (velocity of sound in gas which cools during expansion (m/s))

γ = adiabatic exponent; for oxygen = 1.4

g = acceleration due to gravity; $9.81 \text{ (m/sec}^2\text{)}$

R' = individual gas constants.

In these formulae flow conditions are assumed to be restricted. Experience has shown that this simplification can be used to the first approximation.

The following formula is used to calculate cooling at the outlet opening:

$$T/T_1 = 1 - \frac{(\gamma - 1)(v^2 - a_s^2)}{2a_s^2}$$

T_2 = temperature of the expanding gas at Laval velocity (K)

Upon obtaining the sonic flow T_2 becomes $= 0.829 T_1$. It has been shown that even given rapid compression of the gas in the pipe, no ignition of the metal parts or of the organic residue occurs since the perforated pipe forms in addition a "pressure rarefaction zone" and thereby cooling takes place, whereas the compression wave is clearly only formed on the most extreme peak of the pressure wave.

If residual oil is present in the borehole, or collects during the process, or if irremovable bituminous residues foul the wall of the pipe, there is an increased danger of explosion in the presence of oxygen. It has now been found that this danger can be eliminated if high grade grit or sand or Raschig rings is introduced

and packed into the cavities of the reservoir in which there is a danger of explosion. Grit packing 8 is therefore introduced into the extended liner 1, here having the form of a "sump", in order to render any residual oil present harmless in the presence of oxygen.

Obviously, in place of high-grade steel, copper, brass, Inconel or Monel or other nickel alloys can be used as material for the liner. It is of particular advantage to maintain the oxygen concentration below 96% as this then rules out the possibility of autothermal (self-sustaining) combustion spreading. According, in the subject method it is not essential that the oxygen be of the highest purity.

Occasionally admixture of inert gases, such as nitrogen, carbon dioxide or steam, is recommended in order to desensitize the oxygen. The oxygen should then be between about 80% and 96% pure.

The method for starting the operation of underground combustion (as described for example in German Auslegeschrift 2,263,960 and in German Patent No. 2,132,679) is performed in the following sequence of steps.

Phase I

The pressure in the petroleum reservoir is reduced as far as is possible and is necessary.

Since it is known that in an explosion the pressure can increase to 5 to 10 times the initial pressure, it is considered expedient for safety reasons to reduce the pressure in the reservoir, in a manner known per se, to slightly above the bubble-point of the reservoir liquid.

The igniters are injected into the upper region of the reservoir via the annulus, in the approximate sequence diesel oil, chemical igniters, water. The dimensions and composition of the chemical igniters can be determined for example in the manner described in German Auslegeschrift 2,263,960. The diesel oil slug should be of the same magnitude (volume) as the chemical igniters slug. By means of nitrogen all the igniters are injected into the formation via the annulus. Simultaneously nitrogen is injected at a low rate (low excess pressure) into the reservoir via injection pipe 3, in order to prevent the igniters circulating back into the high-grade steel linear and injection pipe. When the chemical igniters are injected into the formation the ignition gas (20% - 80% volume oxygen concentration) is injected at the specific rate of approx. $10 - 50 \text{ m}^3/\text{m}^2$ rock surface per hour (gas volumes under normal conditions) until thermocouples set into the cement casing 4 of liner 1 indicate by an increase in temperature that ignition has taken place. The preferred specific injection rate of the gas is about $30 \text{ m}^3/\text{m}^2\text{h}$. The gas is subsequently injected at the same rate until the combustion front is at a distance of approx. 3 - 30 m from the injection borehole. The preferred distance from the combustion front to the injection borehole is about 5 to 15 m. There are then no more liquid hydrocarbons present in this zone, only solid oxidation residues.

Phase II

The oxygen concentration in the injection gas is increased in stages and the injection rate is increased to the maximum oxygen rate as set down in the process. The cross-sectional area of the perforations is calculated from this rate, in order to achieve critical flow conditions. The maximum oxygen rate depends on the process to be performed. It is pointed out here that even in

subcritical flow conditions, an adequate cooling effect can be achieved in the borehole region.

Water is simultaneously injected via the annulus. The water/oxygen ratio should be within the range of from 1 - 15 m³ water per 1000 m³ oxygen (gas volumes under normal conditions). The oxygen concentration should be increased in stages, e.g. in three stages, from 30% - 50%, from 50% - 70% and from 70% - 90%. The reservoir pressure is increased until it lies within the range of from 80 bar to, for example, 150 bar.

Provision must be made that, in the event of the process being interrupted, nitrogen can be injected at any time into the injection pipe and into the annulus (Phase I) via a by-pass from the surface. This is to ensure that adequate control over the borehole is maintained (prevention of reflux, cooling down the borehole).

We claim:

1. A method for starting the operation of a process for the recovery of energy raw materials from a subterranean formation penetrated by a borehole comprising the steps of:

- a. introducing into the upper region of said formation igniters known per se,
- b. simultaneously introducing into the lower region of said formation an inert gas thereby preventing intrusion of said igniters into said lower region,
- c. subsequently introducing a gas with a predetermined oxygen concentration and injection rate into the lower region until ignition occurs and a combustion front is formed as indicated by a corresponding increases in temperature,
- d. continuing injection of said gas at said injection rate until the combustion front has been moved a predetermined distance into said formation,
- e. increasing said injection rate of said gas and/or oxygen concentration in said gas to a maximum rate and/or concentration respectively,
- f. injecting the said gas with the final oxygen concentration through at least one radially arranged outlet opening into the formation with a pressure ratio of flow-in pressure to discharge pressure at the outlet opening of 1.2 to 2.5, and
- g. simultaneously injecting water into the upper region of said formation.

2. The method according to claim 1, characterized by injecting the oxygen at a pressure at which it flows into the reservoir at the velocity of sound.

3. The method according to claim 1, characterized in that, at the beginning of the injection processes, the reservoir pressure is lowered to slightly above the bubble-point of the reservoir liquid.

4. The method according to claim 1, characterized in that the injection processes are carried out via an injection borehole which, in the region of the reservoir, is divided into an upper and a lower injection region with no direct connection between these two regions.

5. The method according to claim 1, characterized by the oxygen concentration of the gas to be injected amounting to from 20 to 80 vol. %.

6. The method according to claim 1, characterized by increasing the injection rate and/or oxygen concentration in steps.

7. The method of claim 1, characterized by admixing with the process oxygen an inert gas.

8. The method of claim 7, wherein said inert gas is nitrogen, carbon dioxide, steam and mixtures thereof.

9. The method of claim 1, wherein said inert gas is present in amounts of from 4 to 20 vol. %.

10. The method according to claim 1, characterized by the specific injection rate of the gas amounting to from 10 to 50 m³/m²h.

11. The method of claim 10 wherein the specific injection-rate is about 30 m³/m²h.

12. The method according to claim 1, characterized in that the distance from the combustion front to the injection borehole amounts to from 3 to 30 m, before the injection rate and/or oxygen concentration are stepwise increased to their final value.

13. The method of claim 12 wherein the distance from the combustion front to the injection borehole is 5 to 15 m.

14. The method according to claim 1, characterized by selecting a H₂O/O₂ ratio of 1 to 15 m³/1000 m³ O₂ (gas volumes at normal conditions).

15. The method according to claim 1, characterized in that all cavities in the reservoir region of the injection borehole in which a contact between oxygen and combustible materials is possible, are filled with porous filling material (e.g. sand, grit packing, Raschig rings).

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