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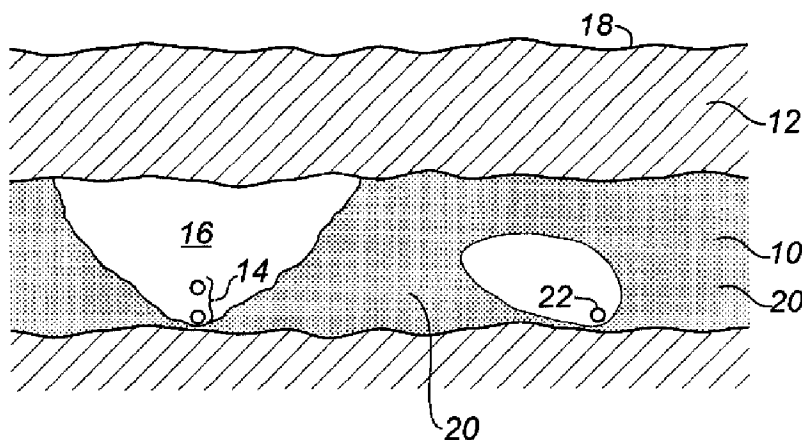
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(54) Titre : PROCEDE DE RECUPERATION DU PETROLE LOURD PAR DRAINAGE PAR GRAVITE AU MOYEN DE LA VAPEUR

(54) Title: STEAM-ASSISTED GRAVITY DRAINAGE HEAVY OIL RECOVERY PROCESS



(57) Abrégé/Abstract:

A pair of vertically spaced, parallel, co-extensive, horizontal injection and production wells and a laterally spaced, horizontal offset well are provided in a subterranean reservoir containing heavy oil. Fluid communication is established across the span of formation extending between the pair of wells. Steam-assisted gravity drainage ("SAGD") is then practised by injecting steam through the injection well and producing heated oil and steam condensate through the production well, which is operated under steam trap control. Cyclic steam stimulation is practised at the offset well. The steam chamber developed at the offset well tends to grow toward the steam chamber of the SAGD pair, thereby accelerating development of communication between the SAGD pair and the offset well. This process is continued until fluid communication is established between the injection well and the offset well. The offset well is then converted to producing heated oil and steam condensate under steam trap control as steam continues to be injected through the injection well. The process yields improved oil recovery rates with improved steam consumption.

1 **"STEAM-ASSISTED GRAVITY DRAINAGE**
2 **HEAVY OIL RECOVERY PROCESS"**

3 **ABSTRACT OF THE DISCLOSURE**

4 A pair of vertically spaced, parallel, co-extensive, horizontal injection
5 and production wells and a laterally spaced, horizontal offset well are provided
6 in a subterranean reservoir containing heavy oil. Fluid communication is
7 established across the span of formation extending between the pair of wells.
8 Steam-assisted gravity drainage ("SAGD") is then practised by injecting steam
9 through the injection well and producing heated oil and steam condensate
10 through the production well, which is operated under steam trap control.
11 Cyclic steam stimulation is practised at the offset well. The steam chamber
12 developed at the offset well tends to grow toward the steam chamber of the
13 SAGD pair, thereby accelerating development of communication between the
14 SAGD pair and the offset well. This process is continued until fluid
15 communication is established between the injection well and the offset well.
16 The offset well is then converted to producing heated oil and steam
17 condensate under steam trap control as steam continues to be injected
18 through the injection well. The process yields improved oil recovery rates with
19 improved steam consumption.

TECHNICAL FIELD

This invention relates generally to a process for recovering heavy oil from a subterranean reservoir using a combination of steam-assisted gravity drainage and cyclic steam stimulation.

BACKGROUND ART

Over the past 20 years, there has been an evolution in the thermal processes applied for recovering heavy, viscous oil from subterranean reservoirs in Alberta.

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

There are problems associated with the cyclic process. More particularly:

- The fracturing tends to occur vertically along a direction dictated by the tectonic regime present in the formation. In the Cold Lake area of Alberta, fracturing tends to occur along a north-east trend;

- 1 • When steam is injected, it tends to preferentially move through the
2 fractures and heat outwardly therefrom. As a result, the heated
3 steam chamber that is developed tends to be relatively narrow and
4 extends along this north-east direction from opposite sides of the
5 well;
- 6 • Therefore large bodies of unheated oil are left in the zone extending
7 between adjacent wells and their linearly extending steam
8 chambers; and
- 9 • The process is not efficient with respect to steam utilization.
10 Steam/oil ratios are relatively high because the steam is free to be
11 driven down any permeable path.

12 In summary then, huff and puff gives relatively low oil recovery and the
13 steam/oil ratio is relatively high.

14 A more recent, successfully demonstrated process involves a
15 mechanism known as steam-assisted gravity drainage ("SAGD").

16 One embodiment of the SAGD process is described in Canadian
17 patent 1,304,287. This embodiment involves:

- 18 • Providing a pair of coextensive horizontal wells spaced one above
19 the other. The spacing of the wells is typically 5 – 8 meters. The
20 pair of wells is located close to the base of the formation;
- 21 • The span of formation between the wells is heated to mobilize the
22 oil contained therein. This may be done by circulating steam
23 through each of the wells at the same time to create a pair of "hot
24 fingers". The span is slowly heated by conductance;

- 1 • When the oil in the span is sufficiently heated so that it may be
2 displaced or driven from one well to the other, fluid communication
3 between the wells has been established and steam circulation
4 through the wells is terminated;
- 5 • Steam injection at less than formation fracture pressure is now
6 initiated through the upper well and the lower well is opened to
7 produce draining liquid. Injected steam displaces the oil in the
8 interwell span to the production well. The appearance of steam at
9 the production well indicates that fluid communication between the
10 wells is now complete;
- 11 • Steam-assisted gravity drainage recovery is now initiated. Steam is
12 injected through the upper well at less than fracture pressure. The
13 production well is throttled to maintain steam trap conditions. That
14 is, throttling is used to keep the temperature of the produced liquid
15 at about 6 – 10°C below the saturation steam temperature at the
16 production well. This ensures that a short column of liquid is
17 maintained over the production well, thereby preventing steam from
18 short-circuiting into the production well. As the steam is injected, it
19 rises and contacts cold oil immediately above the upper injection
20 well. The steam gives up heat and condenses; the oil absorbs heat
21 and becomes mobile as its viscosity is reduced. The condensate
22 and heated oil drain downwardly under the influence of gravity. The
23 heat exchange occurs at the surface of an upwardly enlarging
24 steam chamber extending up from the wells. The chamber is
25 fancifully depicted in Figure 1. The chamber is constituted of

1 depleted, porous, permeable sand from which the oil has largely
2 drained and been replaced by steam.

3 • The steam chamber continues to expand upwardly and laterally
4 until it contacts the overlying impermeable overburden. The steam
5 chamber has an essentially triangular cross-section. If two laterally
6 spaced pairs of wells undergoing SAGD are provided, their steam
7 chambers grow laterally until they contact high in the reservoir. At
8 this stage, further steam injection may be terminated and
9 production declines until the wells are abandoned.

10 The SAGD process is characterized by several advantages, relative to
11 huff and puff. Firstly, it is a process involving relatively low pressure injection
12 so that fracturing is not likely to occur. The injected steam simply rises from
13 the injection point and does not readily move off through fractures and
14 permeable streaks, away from the zone to be heated. Otherwise stated, the
15 steam tends to remain localized over the injection well in the SAGD process.
16 Secondly, steam trap control minimizes short-circuiting of steam into the
17 production well. And lastly, the SAGD steam chambers are broader than
18 those developed by fracturing and huff and puff, with the result that oil
19 recovery is generally better. It has been demonstrated the better steam/oil
20 ratio and oil recovery can be achieved using the SAGD process.

21 However there are a number of problems associated with the SAGD
22 process which need addressing. More particularly:

23 • There is a need to more quickly heat the formation laterally between
24 laterally spaced wells; and

- As previously stated and as illustrated in Figure 1, the steam chambers produced by pairs of SAGD wells are generally triangular in cross-section configuration. As a result there is unheated and unrecovered oil left between the chambers in the lower reaches of the reservoir (this is indicated by cross-hatching in Figure 1).

It is the objective of the present invention to provide a SAGD process which is improved with respect to these shortcomings.

SUMMARY OF THE INVENTION

The invention is concerned with a process for recovering heavy viscous oil from a subterranean reservoir comprising the steps of:

- (a) providing a pair of spaced apart, generally parallel and co-extensive, generally horizontal steam injection and production wells;
- (b) establishing fluid communication between the wells;
- (c) practising steam-assisted gravity drainage to recover oil by injecting steam at less than formation fracture pressure (typically at a low pressure that is greater than but close to formation pressure) through the injection well and producing steam condensate and heated oil through the production well while throttling the production well as required to keep the produced liquid temperature less than the steam saturation temperature at the injection well (that is, operating the production well under steam trap control);

1 (d) providing a horizontal third well, generally parallel and co-
2 extensive with the injection and production wells and preferably
3 located at about the same general elevation as the pair of wells,
4 the third well being laterally offset from the pair of wells, typically
5 at a distance of about 50 to 80 m; and

6 (e) contemporaneously practising cyclic steam stimulation at the
7 offset well, preferably by injecting steam at less than formation
8 fracture pressure, more preferably at a "high" pressure which is
9 greater than that being used at the SAGD pair, and preferably
10 by operating the well during the production phase under steam-
11 trap control conditions, to develop a steam chamber which
12 causes lateral heating of the span of reservoir formation
13 between the pair of wells and the third well and to periodically
14 produce heated oil through the offset well.

15 Preferably, steps (c) and (e) are continued to establish fluid communication
16 between the injection well and the offset well and then the offset well is
17 converted to production. Steam-assisted gravity drainage procedure is
18 continued with the offset well being operated under steam-trap control to
19 produce part or all of the draining fluid.

20 The invention utilizes the discovery that practising SAGD and huff and
21 puff contemporaneously at laterally spaced horizontal wells leads to faster
22 developing fluid communication between the two well locations. When SAGD
23 and huff and puff are practised at relatively low and high pressures, there is a
24 greater tendency for the huff and puff steam chamber to grow toward the
25 SAGD steam chamber during the injection phase at the third well. During the

1 production phase at the third well, the injection pressure at the SAGD pair
2 preferably may be increased (while keeping it at less than fracture pressure)
3 to induce lateral growth of the SAGD steam chamber toward the third well.

4 The invention further utilizes the discovery that:

- 5 • if SAGD and huff and puff are practised contemporaneously using
6 horizontal wells at laterally spaced locations; and
- 7 • if the huff and puff well is converted to fluid production under steam
8 trap control when fluid communication has been established
9 between the locations;

10 then more extensive heating of the lower reaches of the reservoir between the
11 locations may be achieved. This leads to greater oil recovery.

12 The expression "contemporaneously" as used herein and in the claims
13 is to be interpreted to encompass both: (1) simultaneously conducting SAGD
14 and huff and puff steam injection at the two locations; and (2) intermittently
15 and sequentially repetitively conducting SAGD steam injection at the first
16 location and then huff and puff steam injection at the second location, to
17 minimize required steam production facilities.

18 In another preferred feature, at the stage where fluid communication
19 between the injection well and the offset well have been established and
20 SAGD is being practised using all three wells, a small amount of nitrogen or
21 methane could be injected with the steam. We contemplate using about 1 –
22 2% added N₂ or CH₄ gas. It is anticipated that the added gas will accumulate
23 along chamber surfaces where there is little liquid flow to the producing wells,
24 to thereby reduce heat loss.

1 It is further contemplated that the invention can be put into practice in a
2 staged procedure conducted across a reservoir by: (a) contemporaneously
3 practising SAGD at a first location and huff and puff at a second laterally
4 spaced location until fluid communication is established; (b) then practising
5 SAGD alone at the first pair, with the third well at the second location being
6 produced; (c) providing SAGD wells at a third location laterally spaced from
7 the second location; and repeating steps (a) and (b) at the second and third
8 locations and repeating the foregoing procedure to incrementally develop and
9 produce the reservoir.

10

11

DESCRIPTION OF THE DRAWINGS

12 Figure 1 is a fanciful sectional view showing the wells and steam
13 chambers developed by operating spaced apart, side-by-side pairs of wells
14 practising SAGD in accordance with the prior art;

15 Figures 2 and 3 are fanciful sectional views showing the wells and
16 steam chambers developed by practising SAGD and cyclic stimulation in
17 tandem at laterally offset locations in the initial (Figure 2) and mature stages
18 (Figure 3);

19 Figure 4 is a block diagram setting forth the steps of the present
20 invention;

21 Figure 5 is a numerical grid configuration used in numerical simulation
22 runs in developing the present invention;

23 Figure 6 is a plot setting forth the reservoir characteristics for three
24 layers making up the grid of Figure 3;

1 Figure 7 is a plot of a series of temperature profiles developed by a
2 numerical simulation run over time in the grid by practising the baseline case
3 of SAGD operation only at the left hand side of the grid;

4 Figure 8 is a plot of a series of temperature profiles developed by a
5 numerical simulation run over time in the grid by practising SAGD only for 6
6 years and then alternating SAGD and huff and puff using an offset well, under
7 mild conditions;

8 Figure 9 is a plot of a series of temperature profiles developed by a
9 numerical simulation run over time in the grid by practising SAGD only for 3
10 years and then alternating SAGD and huff and puff using an offset well, under
11 aggressive conditions;

12 Figure 10 is a plot of cumulative oil production over time for the run
13 carried out in accordance with the base line case and the two runs carried out
14 in accordance with the combination case, all runs being carried out at mild
15 conditions and, in the case of the first combination run, with offset huff and
16 puff commencing after 3 years and, in the case the case of the second
17 combination run, with offset huff and puff commencing after 6 years;

18 Figure 11 is a plot of cumulative oil production over time for the run
19 carried out in accordance with the combination case at aggressive conditions
20 with offset huff and puff commencing after 3 years;

21 Figure 12 is a plot showing cumulative steam injection for each of the
22 baseline and combination case runs operated at aggressive conditions; and

23 Figure 13 is a plot showing the steam/oil ratio for each of the baseline
24 and combination case runs operated at aggressive conditions.

1 **DESCRIPTION OF THE PREFERRED EMBODIMENT**

2 The steps of providing suitably completed and equipped horizontal
3 wells and operating them to practice SAGD and huff and puff are within the
4 ordinary skill of those experienced in thermal SAGD and huff and puff
5 operations; thus they will not be further described herein.

6 The discoveries underlying the present invention were ascertained in
7 the course of computer numerical simulation modeling studies carried out on
8 various combinations of thermal recovery procedures, with a view to
9 identifying a process that would yield better recovery in less time than prior art
10 processes.

11 Two procedures tested are relevant to the present invention and are
12 now described.

13 In the first procedure, referred to as the baseline case, numerical
14 simulation runs were carried out using a rectangular numerical grid 1 (see
15 Figure 5) representative of a block of oil reservoir existing in the Hilda Lake
16 region of Alberta. The grid was assigned 60 meters in width and was divided
17 into three layers (C1, C2 and C3) which were assigned thicknesses and
18 reservoir characteristics, as set forth in Figure 6. These values generally
19 agreed with the characteristics of the actual reservoir and were used in the
20 simulation. The model further incorporated a pair of horizontal, vertically
21 spaced upper injection and lower production wells 2,3 as shown in Figure 5.
22 The wells 2, 3 were located at the left margin of the grid 1. The baseline case
23 was assigned the following reservoir conditions:

1 initial temperature: 18°C
 2 initial pressure 3100 kPa
 3 GOR: 11
 4 oil viscosity: 10,000 cp
 5 initial water immobile.

6 Fluid communication between wells 2, 3 was developed by practising a
 7 52 day preheat involving simulation of steam circulation in both wells 2 and 3
 8 by adding heat to the grid containing the wells.

9 SAGD operation was initiated at the pair of wells 2,3 using the following
 10 operating parameters:

- 11 • Maximum injection pressure - 3110 kPa
- 12 • Maximum injection rate - 500 m³/d
- 13 • Steam quality - 95%
- 14 • Minimum production pressure - 3100 kPa with steam trap
 15 control.

16 Figure 7 shows periodic temperature profiles for a numerical simulation
 17 run carried out over a hypothetical 15 year period.

18 In the second procedure, referred to as the 'combination case', runs
 19 were carried out by:

- 20 • practising SAGD for several years at the pair of wells at the left
 21 hand side of the grid;
- 22 • then initiating huff and puff (cyclic steam stimulation) at an offset
 23 well 4 located at the right hand side of the grid; and

- 1 • thereafter periodically alternating huff and puff at well 4 and SAGD
2 at wells 2,3 (it was assumed that steam capacity was only sufficient
3 to inject steam at the two sides of the grid in alternating fashion).

4 Two runs were carried out according to the combination case
5 procedure under the following conditions. The first run was carried out at
6 relatively mild conditions of steam injection pressure and rate and the second
7 run at more aggressive conditions. More particularly:

8 1st run (SAGD + huff and puff – mild conditions):

- 9 • Maximum injection pressure – 5000 kPa;
- 10 • Maximum injection rate – 500 m³/d;
- 11 • (Both the pressure and injection rate varied. To start, the injection
12 rate was 500 m³/d and the initial pressure was 3100 kPa. As steam
13 was injected, the formation pressure around the well would increase
14 to a maximum of 5000 kPa, at which point the injection rate would
15 reduce to maintain this pressure. As injectivity was increased
16 through heating, the pressure would drop and the injection rate
17 would increase to the maximum of 500 m³/d);
- 18 • Steam quality – 95%;
- 19 • Minimum production pressure – 3100 kPa with steam trap control;
- 20 • Two injection/production cycles at the offset well. One month of
21 injection followed by two months of production followed by three
22 months of injection followed by three months of production, at which
23 time the offset well was converted to full time production under
24 steam trap control;
- 25 • Offset well distance – 60 m;

- 1 • Start huff and puff after 3 years of initial SAGD only. Huff and puff
- 2 duration was nine months. For the remainder of the run, SAGD
- 3 was practised with the offset well acting as a second SAGD
- 4 production well.

5 2nd Run (SAGD + huff and puff – aggressive conditions):

- 6 • Same conditions as the 1st run except for the following:
- 7 • Maximum injection pressure – 10,000 kPa
- 8 • Maximum injection rate – 1000 m³/d
- 9 • Nine months of injection followed by three months of production
- 10 followed by six months of injection followed by three months of
- 11 production at which time the offset well was converted to full
- 12 time production under steam trap control;
- 13 • Offset well distance – 60 m;
- 14 • Start huff and puff after 3 years of initial SAGD only. Huff and
- 15 puff duration was nineteen months. For the remainder of the
- 16 run, SAGD was practised with the offset well acting as a second
- 17 SAGD production well.
- 18 • It will be noted that the two runs differed in the following
- 19 respects:

20	<u>1st Run:</u>	<u>2nd Run:</u>
21	- short cycle	- longer cycle
22	- low injection rate	- higher injection rate
23	- low pressure	- higher pressure.

1 Having reference now to Figure 10, it will be noted that there was an
2 incremental improvement in rate of oil recovery between the combination and
3 baseline cases, commencing after about 6 years, when mild conditions of
4 steam injection pressure and rate were applied.

5 Having reference to Figure 11, it will be noted that there was a larger
6 incremental improvement in rate of oil recovery between the combination and
7 baseline cases, commencing after about 3 years, when the more aggressive
8 conditions of steam injection pressure and rate were applied.

9 Figures 10 and 11 show both an improved amount of oil recovery and
10 an improved rate of recovery.

11 Having reference to Figures 7, 8 and 9, it will be noted:

- 12 • that a comparison of the temperature contours at the ninth, twelfth
13 and fifteenth years of operation for the baseline and combination
14 cases (the latter involving huff and puff operation commencing at
15 the sixth year) with mild steam injection pressure and rate, showed
16 improved lateral extension of the high temperature contour in the
17 combination case; and
- 18 • that a comparison of the temperature contours at the end of nine
19 years of operation of the baseline and combination cases at
20 aggressive steam injection pressure and rate showed only partial
21 lateral extension of the highest temperature contour in the baseline
22 case but complete lateral extension in the combination case.

1 Having reference to Figures 11 and 12 it will be noted:

- 2 • that it took about 7 years for the combination case and 14 years for
3 the baseline case to produce 500,000 m³ of oil; and
4 • that the steam consumed by 7 years of combination case operation
5 was about 125,000 m³ to produce the 500,000 m³ of oil, whereas
6 the steam consumed by 14 years of baseline operation was about
7 165,000 m³ to produce the same amount of oil. (This is reiterated
8 by Figure 13.)

9 In other words, the combination case was more efficient in terms of steam
10 utilization.

11 In summary then, the experimental numerical simulation run data
12 establishes that:

- 13 • faster lateral heating of the reservoir;
14 • greater oil recovery;
15 • faster oil recovery; and
16 • improved steam consumption efficiency;

17 are achieved by the combination case when compared with the baseline case.

1 THE EMBODIMENTS OF THE INVENTION IN WHICH AN
2 EXCLUSIVE PROPERTY OR PRIVILEGE IS CLAIMED ARE DEFINED AS
3 FOLLOWS:

4

5 1. A thermal process for recovering heavy viscous oil from a
6 subterranean reservoir, comprising:

7 (a) providing a pair of spaced apart, generally parallel and co-
8 extensive, generally horizontal steam injection and production wells;

9 (b) establishing fluid communication between the wells;

10 (c) practising steam-assisted gravity drainage to recover oil by
11 injecting steam at less than formation fracture pressure through the injection
12 well and producing steam condensate and heated oil through the production
13 well while throttling the production well as required to keep the produced liquid
14 temperature less than the steam saturation temperature at the injection well;

15 (d) providing a generally horizontal third well, offset from and generally
16 parallel and co-extensive with the injection and production wells; and

17 (e) contemporaneously practising cyclic steam stimulation at the offset
18 well to develop lateral heating of the span of reservoir formation between the
19 pair of wells and the third well and periodically producing heated oil and steam
20 condensate therethrough.

1 2. The process as set forth in claim 1 comprising:
2 continuing steps (c) and (e) to establish fluid communication between
3 the injection well and the third well; and
4 then continuing to inject steam through the injection well and produce
5 heated oil and steam condensate through the third well while throttling the
6 third well as required to keep the produced liquid temperature less than the
7 steam saturation temperature at the injection well.

8
9 3. The process as set forth in claim 1 or 2 comprising throttling the
10 third well during cyclic stimulation as required to keep the produced liquid
11 temperature less than the steam saturation temperature at the injection well.

12
13 4. The process as set forth in claim 2 comprising injecting a small
14 amount of nitrogen or methane together with the steam after fluid
15 communication has been established between the injection well and the third
16 well.

17
18 5. The process as set forth in claim 2 comprising throttling the third
19 well during cyclic stimulation as required to keep the produced liquid
20 temperature less than the steam saturation temperature at the injection well
21 and injecting a small amount of nitrogen or methane together with the steam
22 after fluid communication has been established between the injection well and
23 the third well.

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FIG. 1 (Prior Art)

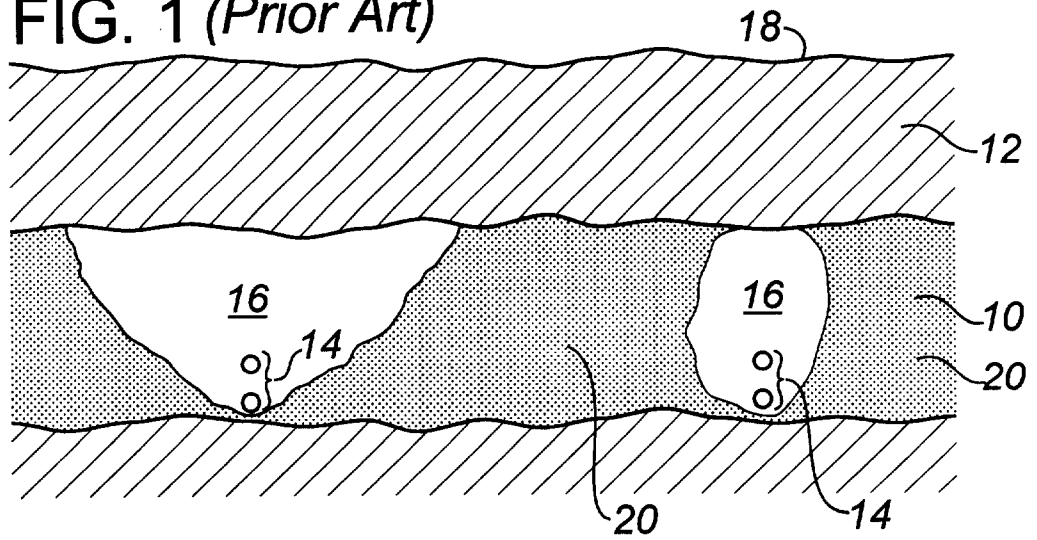


FIG. 2

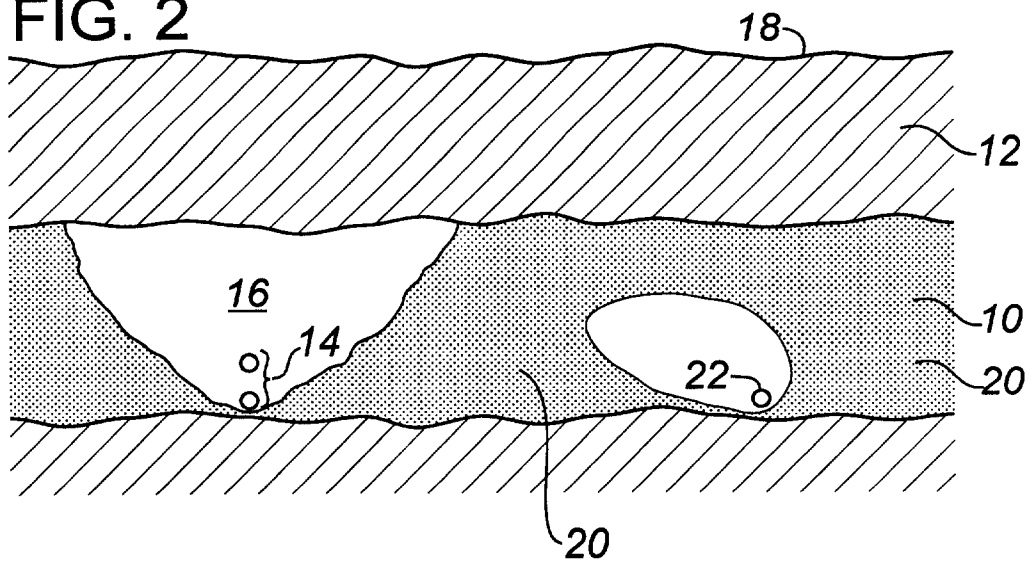
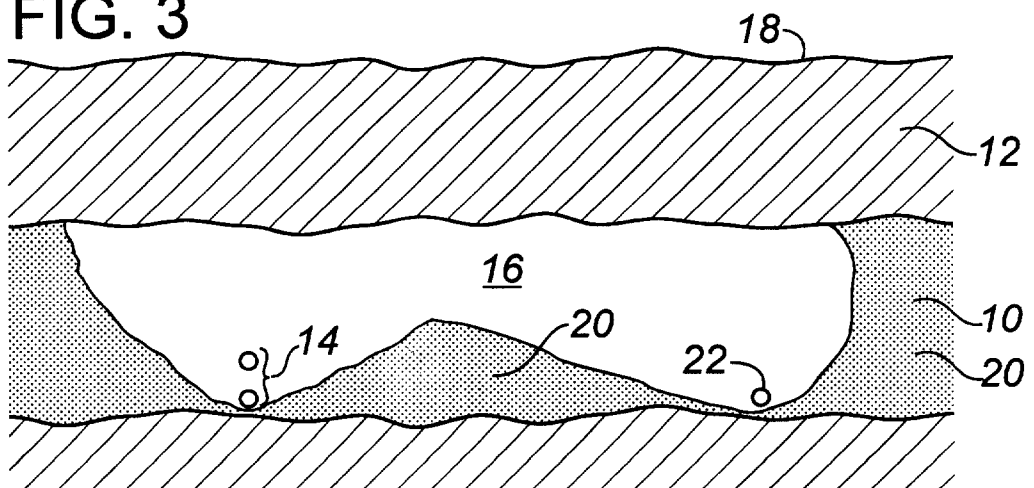


FIG. 3



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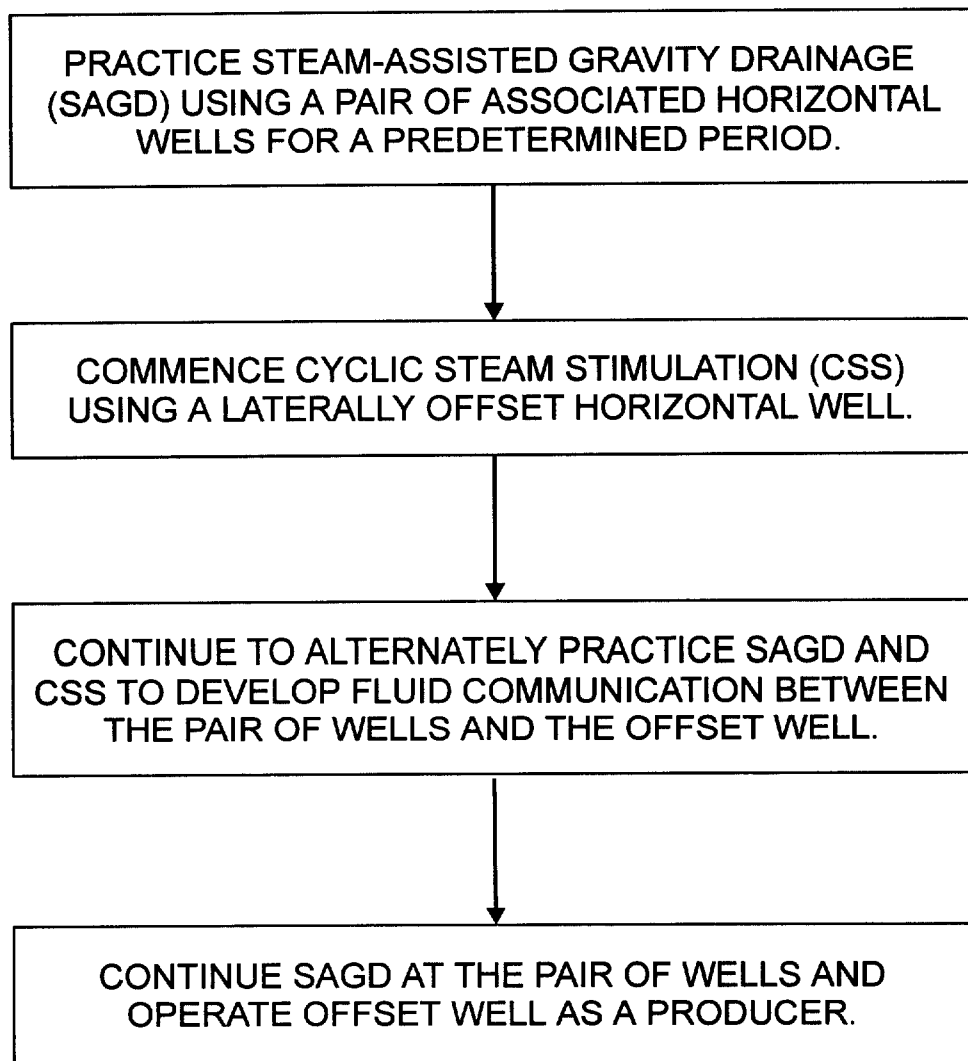
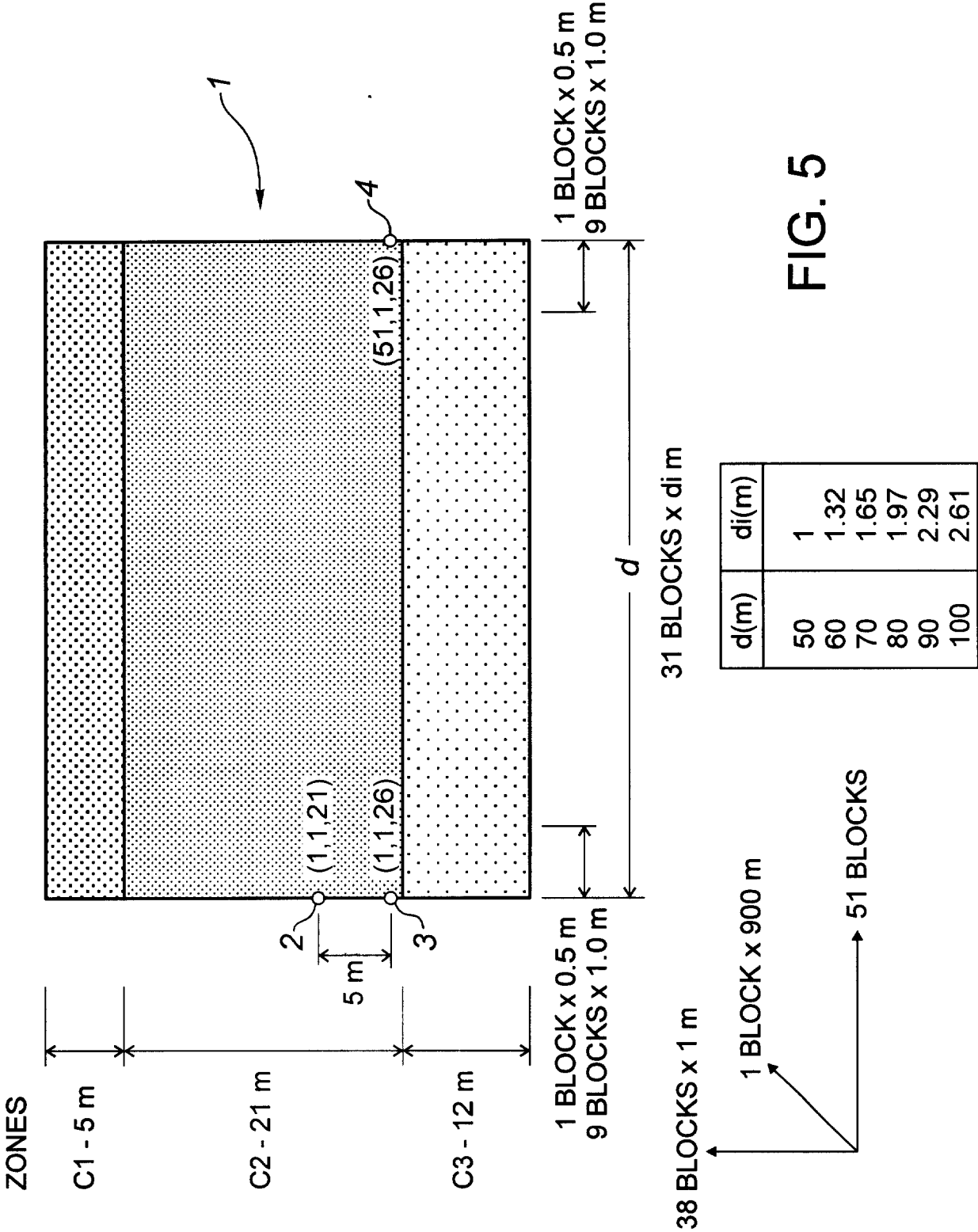


FIG. 4



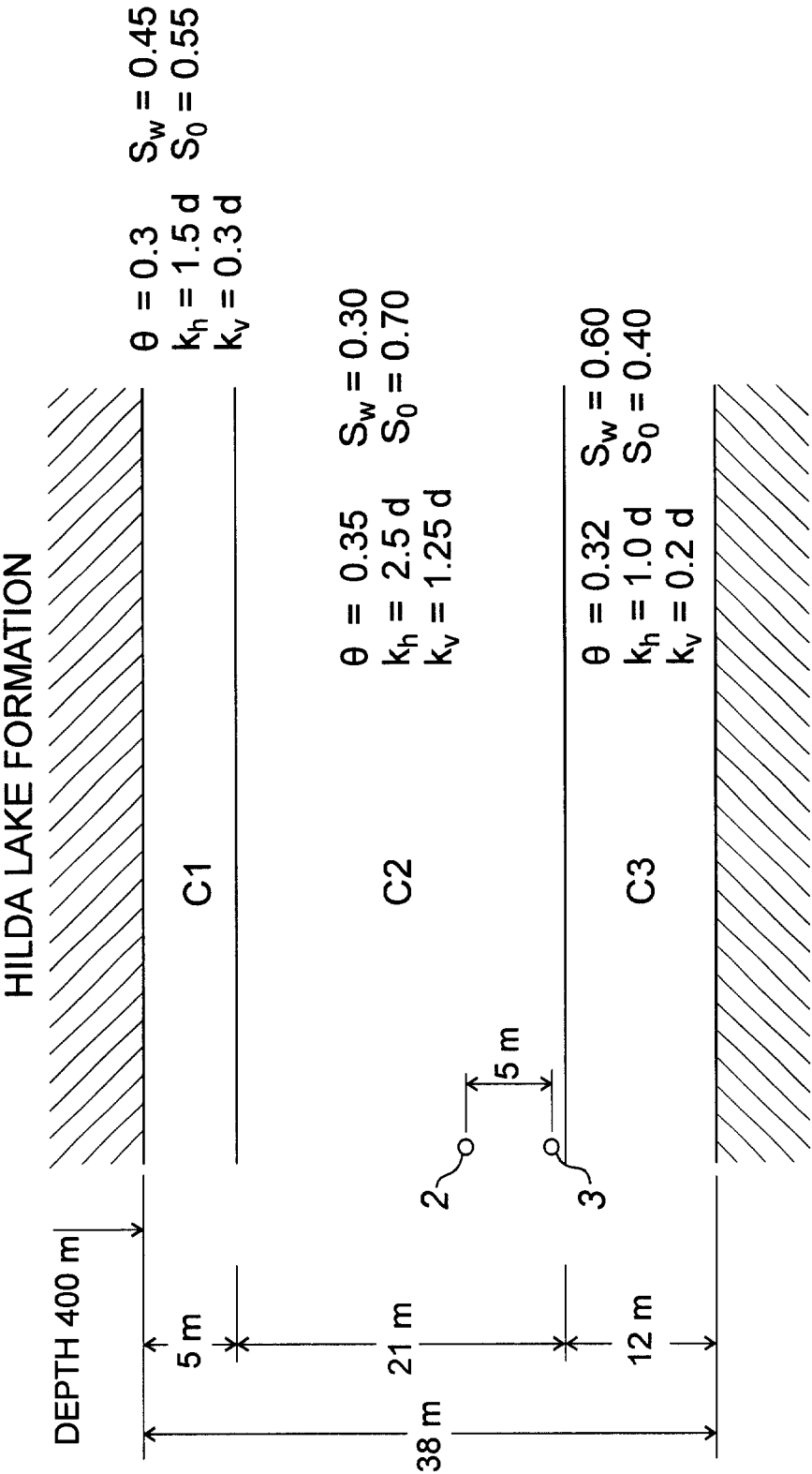


FIG. 6

FIG. 7A

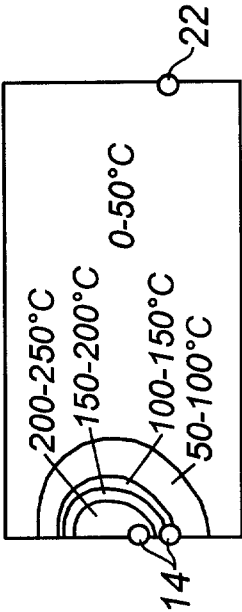


FIG. 7B

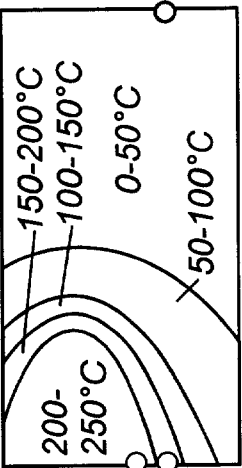


FIG. 7C

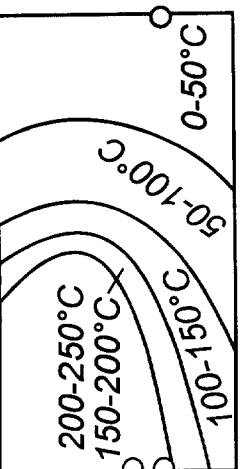


FIG. 7D

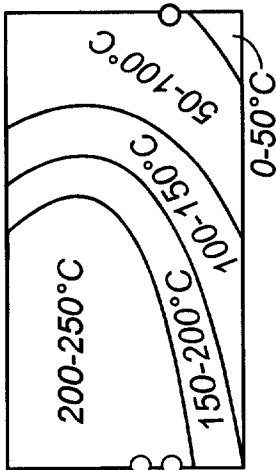


FIG. 7E

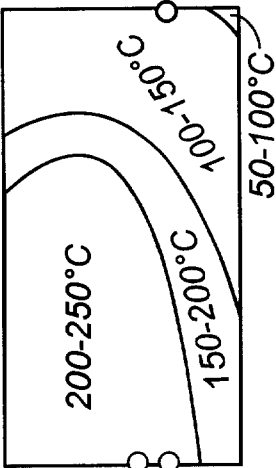


FIG. 7F

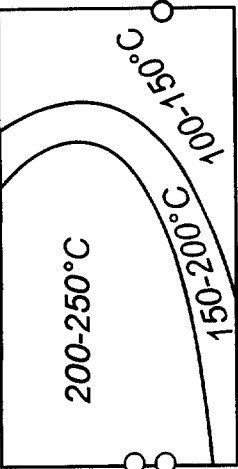


FIG. 8A

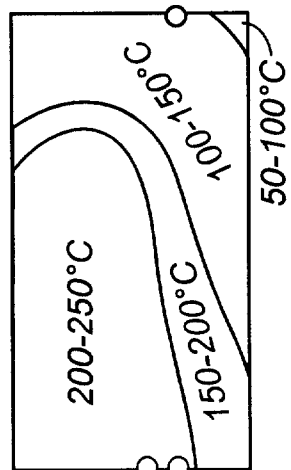


FIG. 8B

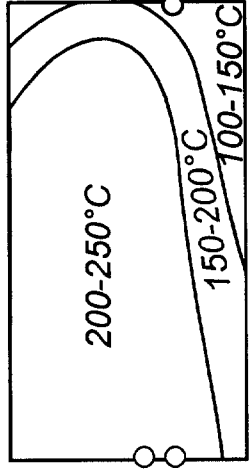
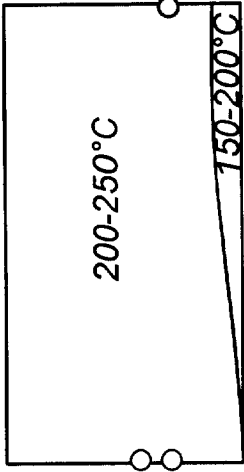
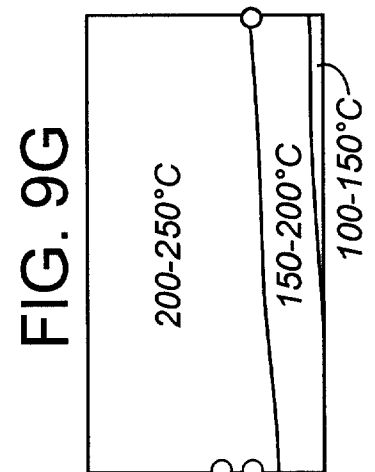
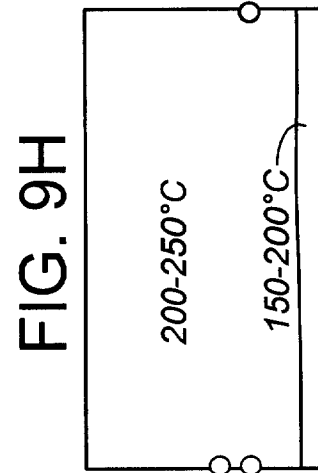
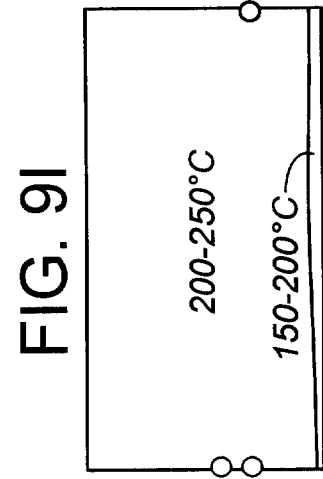
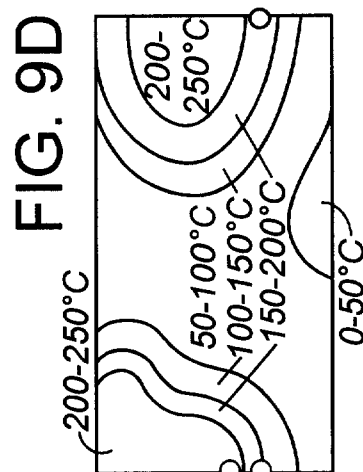
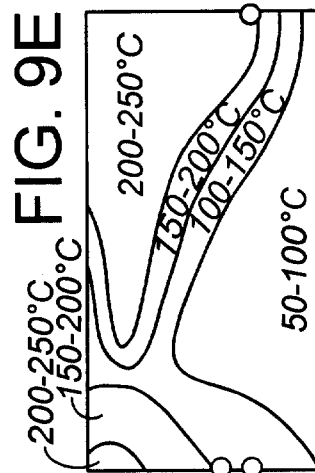
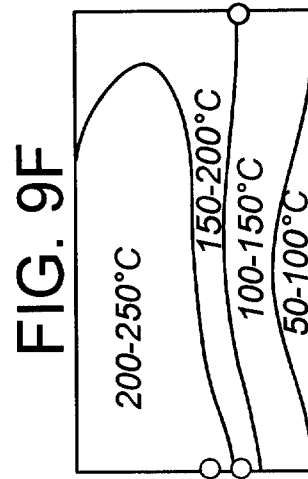
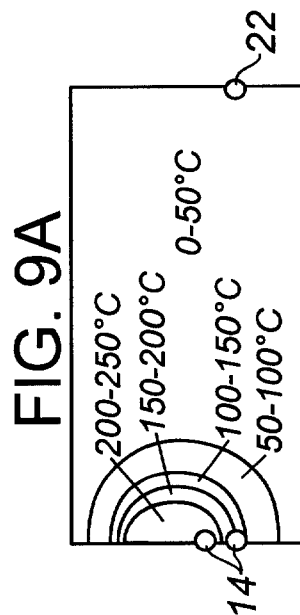
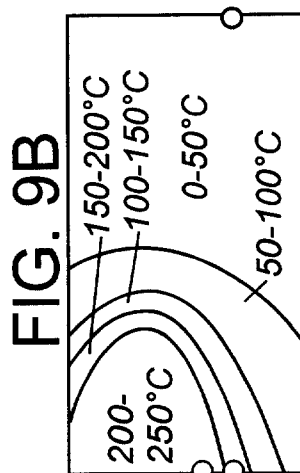
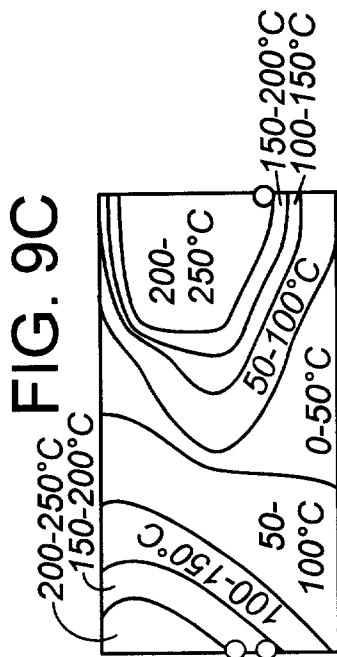


FIG. 8C





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FIG. 10

Cumulative Oil Production, 120 m Well Pair (60 m offset) Spacing, Short Cycles

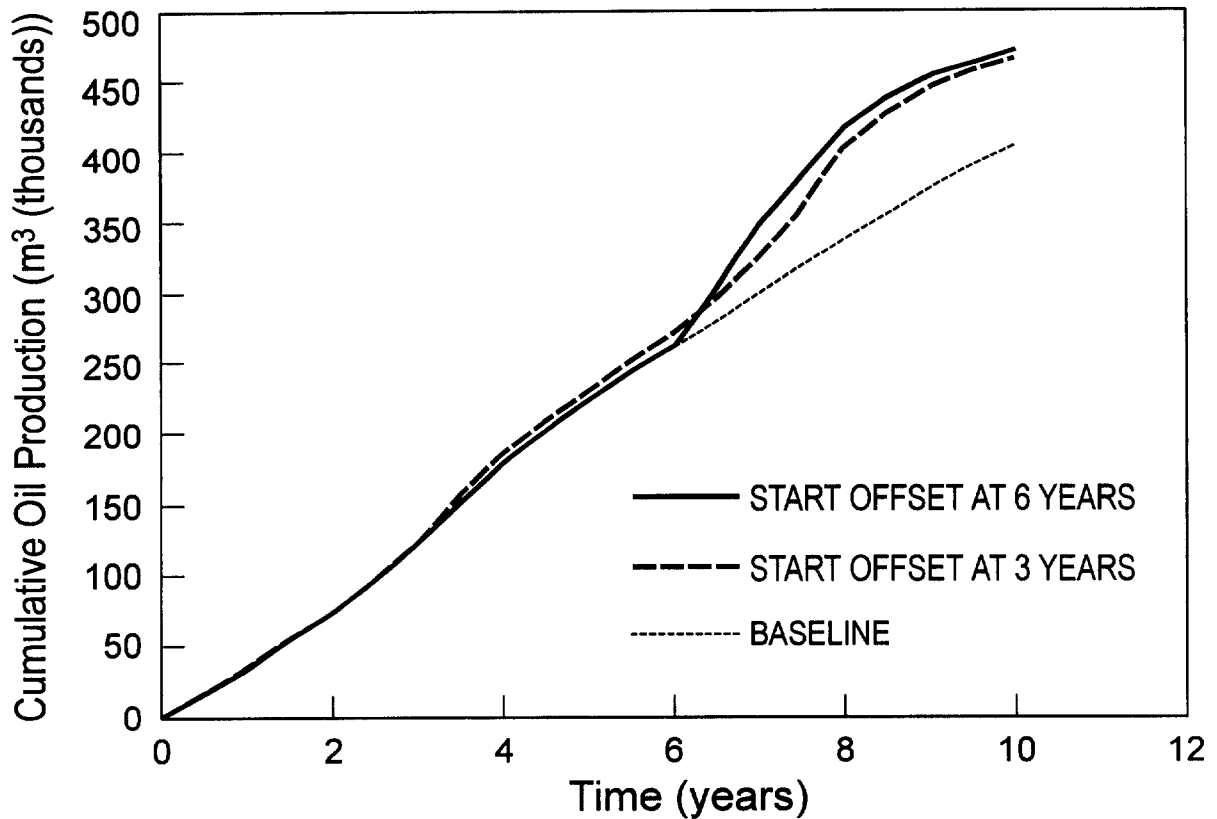
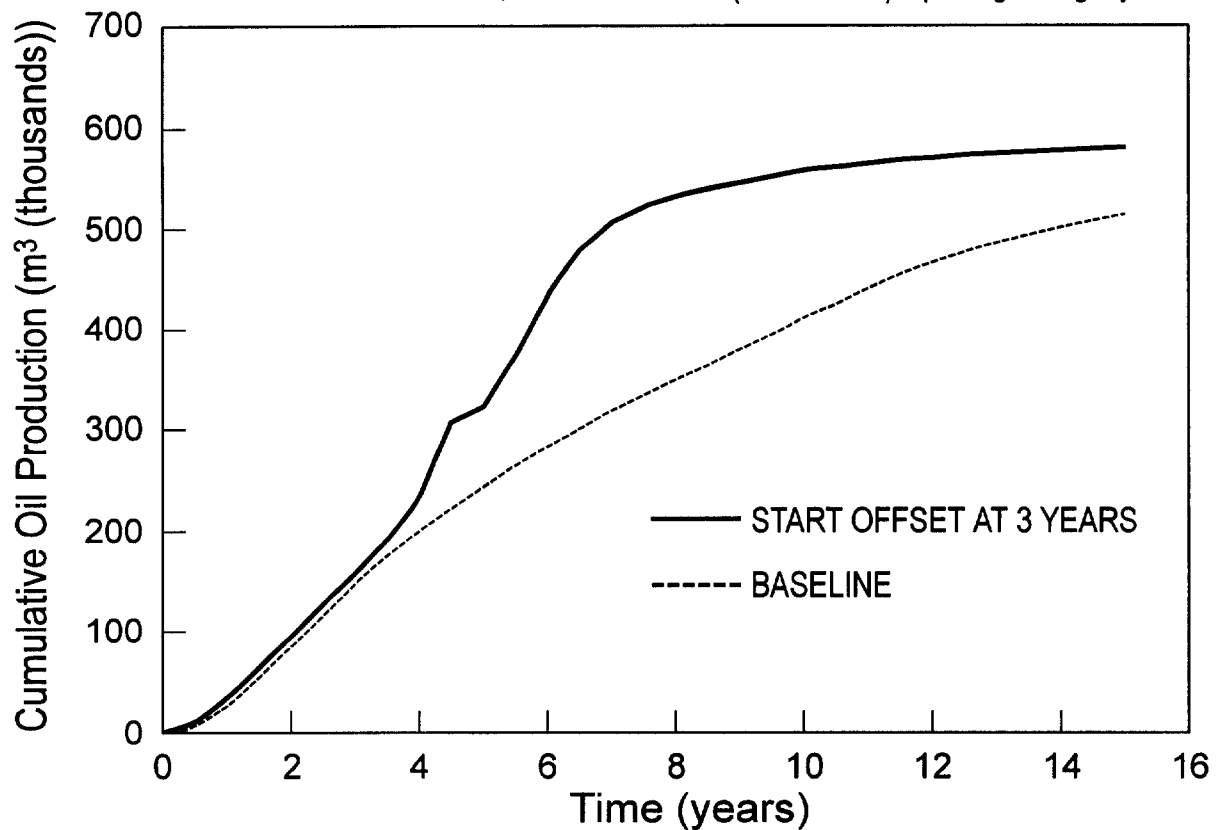


FIG. 11

Cumulative Oil Production, 120 m Well Pair (60 m offset) Spacing, Long Cycles



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FIG. 12

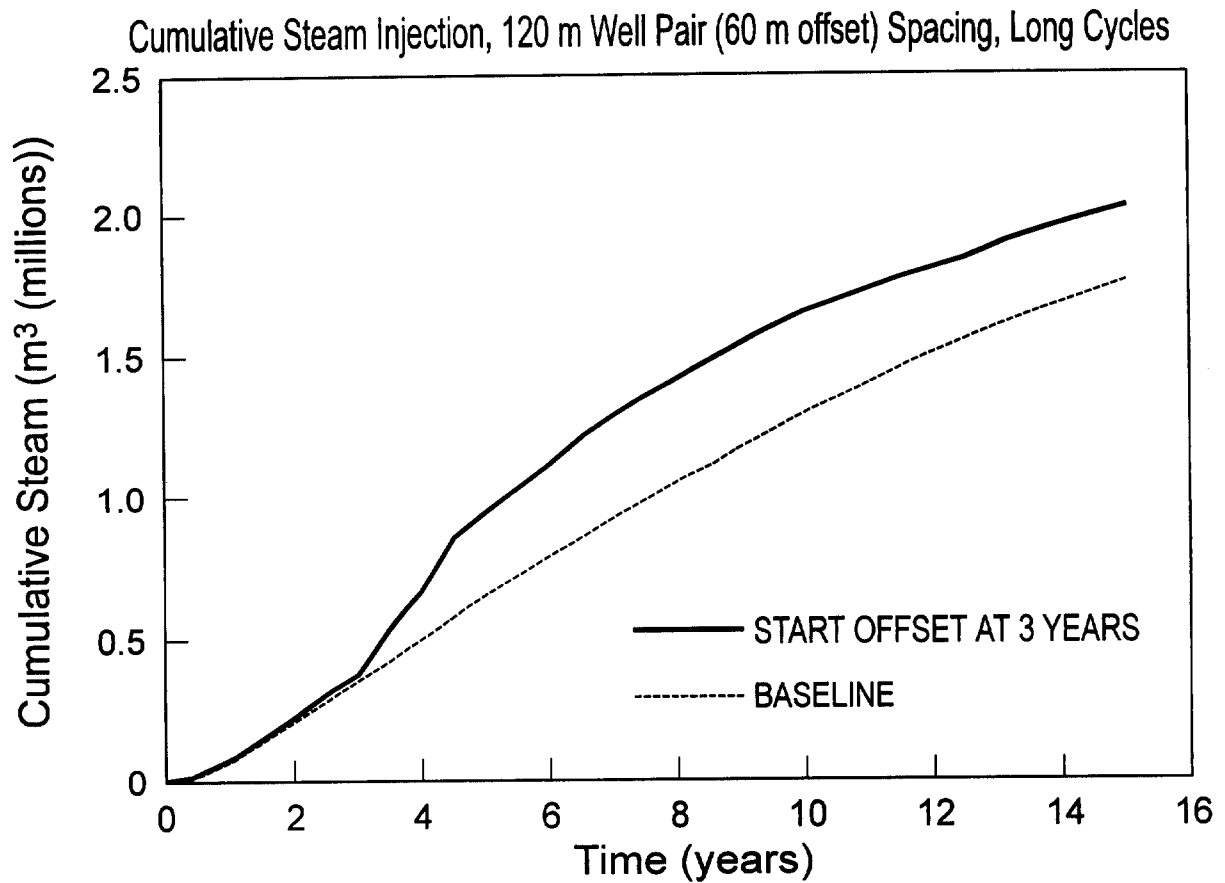
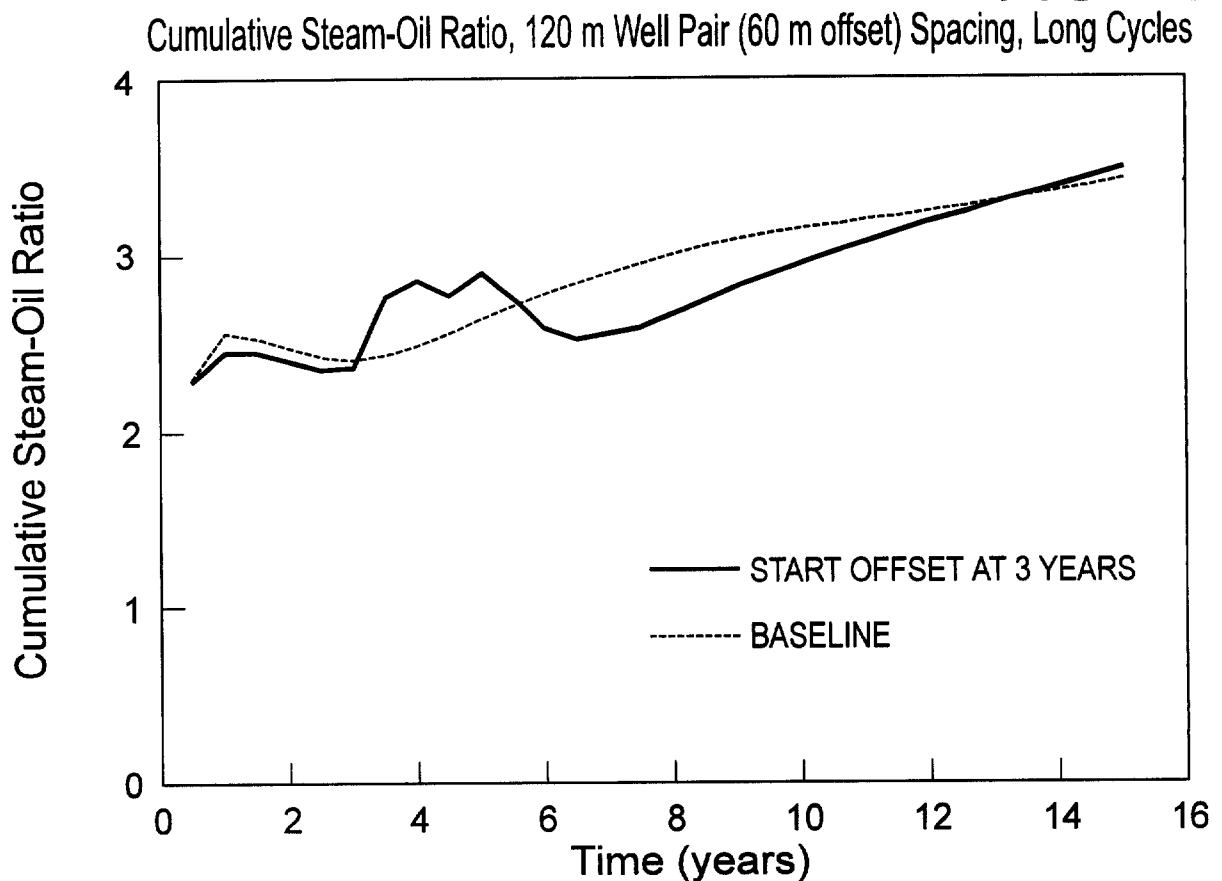


FIG. 13



Temperature Profiles for 120 m (60 m offset) well spacing Baseline SAGD

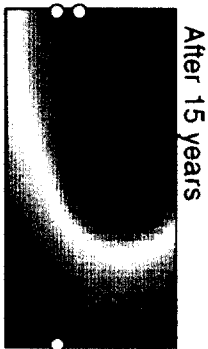
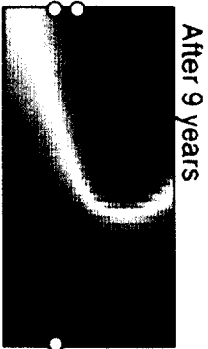
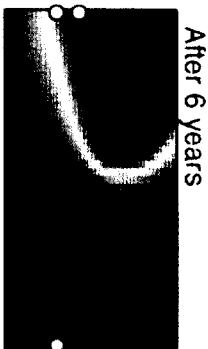
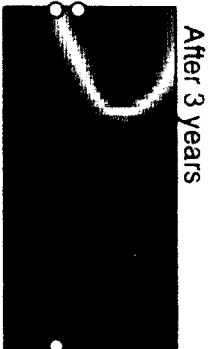
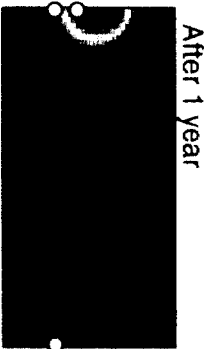
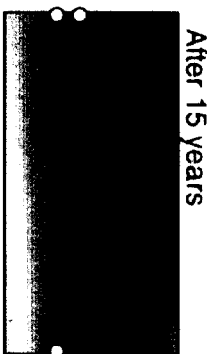
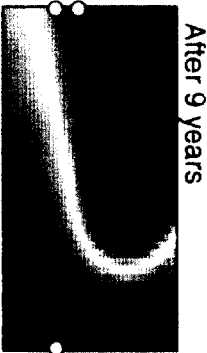
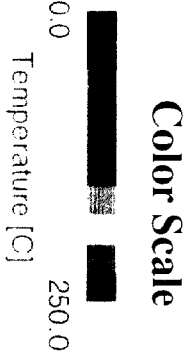


FIGURE 7A-10



SAGD with offset starting @ 6 years

FIGURE 8A-50



Temperature Profiles for 120 m (60 m offset) well spacing

SAGD with offset starting @ 3 years

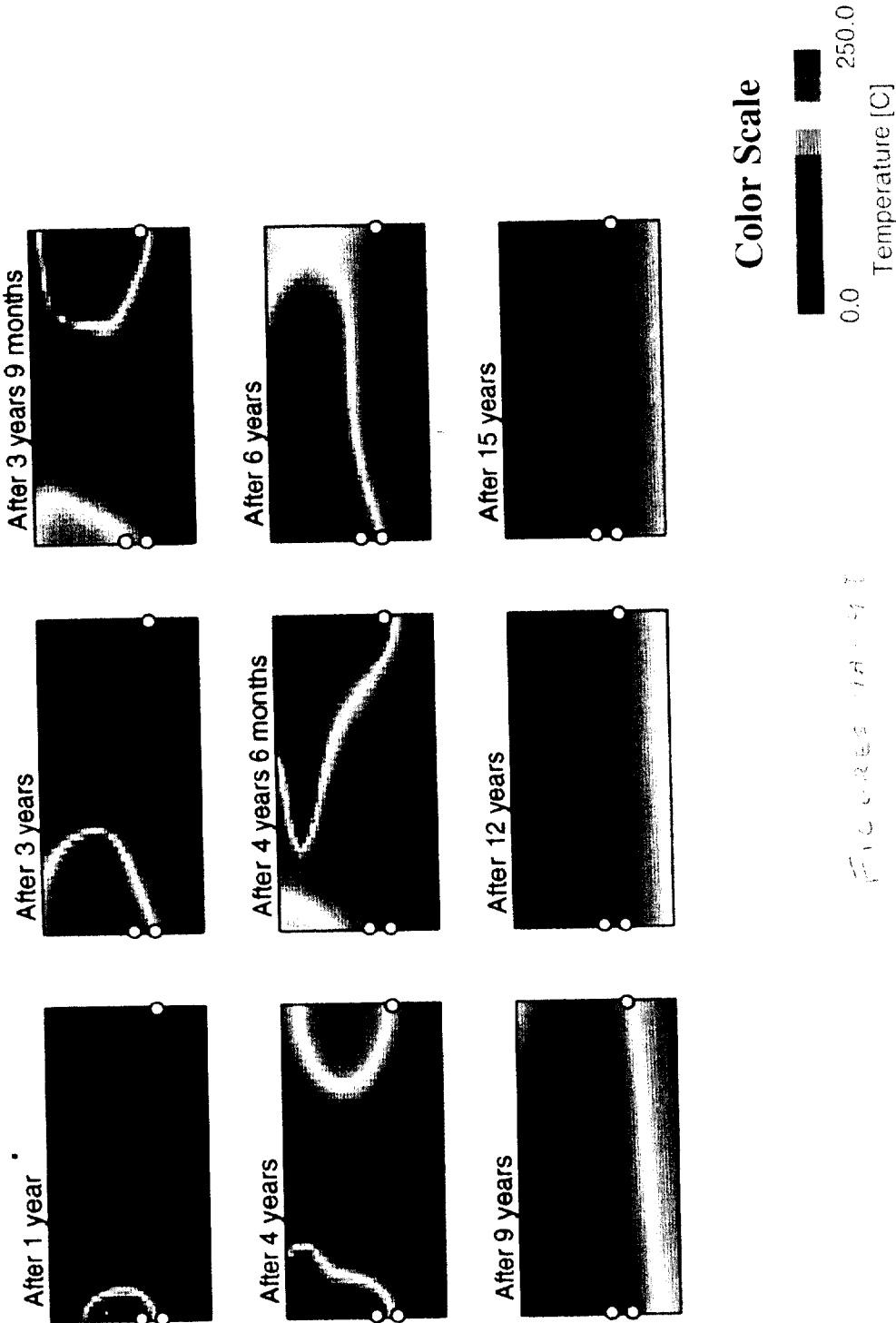


FIGURE 1A-47

