United States Patent

Whitten et al.

[15] **3,705,625**

[45] **Dec. 12, 1972**

[54] **STEAM DRIVE OIL RECOVERY PROCESS**

[72] Inventors: **Derrill Gene Whitten,** Houston, Tex.; **Peter Vanmeurs,** Denver, Colo.

[73] Assignee: **Shell Oil Company,** Houston, Tex.

[22] Filed: **Oct. 22, 1971**

[21] Appl. No.: **191,657**

[52] **U.S. Cl.** **166/252,** 166/263, 166/272

[51] **Int. Cl.** **E21b 43/24**

[58] **Field of Search**.....166/252, 263, 272, 273, 274

[56] **References Cited**

UNITED STATES PATENTS

3,042,114	7/1962	Willman	166/272
3,149,668	9/1964	Arendt	166/274 X
3,185,634	5/1965	Craig, Jr. et al.	166/273
3,223,157	12/1965	Lacey et al.	166/273 X
3,259,186	7/1966	Dietz	166/272 X
3,288,212	11/1966	O'Brien et al.	166/274 X
3,354,954	11/1967	Buxton	166/272
3,369,601	2/1968	Bond et al.	166/274 X
3,412,793	11/1968	Needham	166/272 X
3,474,862	10/1969	Bruist	166/272 X
3,500,915	3/1970	Fitzgerald	166/272

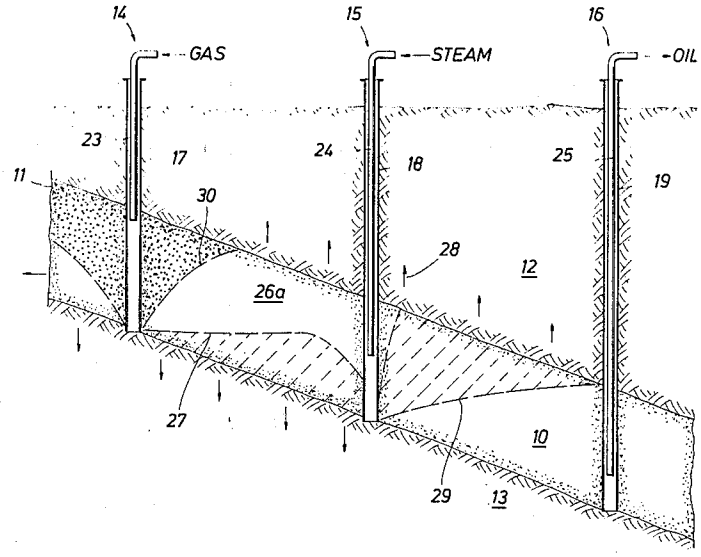
Primary Examiner—Stephen J. Novosad

Attorney—Rand N. Shulman et al.

[57] **ABSTRACT**

A line drive steam injection process in a dipping formation is improved by injecting steam into a row of up-dip wells and producing oil from two or more rows of down-dip wells. After steam breaks through into the first row of down-dip producing wells, steam injection is stopped in the up-dip wells and steam injection is initiated in the row of down-dip wells into which steam has broken through. Simultaneously, a non-condensing gas is injected into the up-dip wells to prevent upward migration into the segment of the formation contacted by steam injected through the original up-dip injectors of steam injected into the new row of down-dip injectors.

9 Claims, 2 Drawing Figures



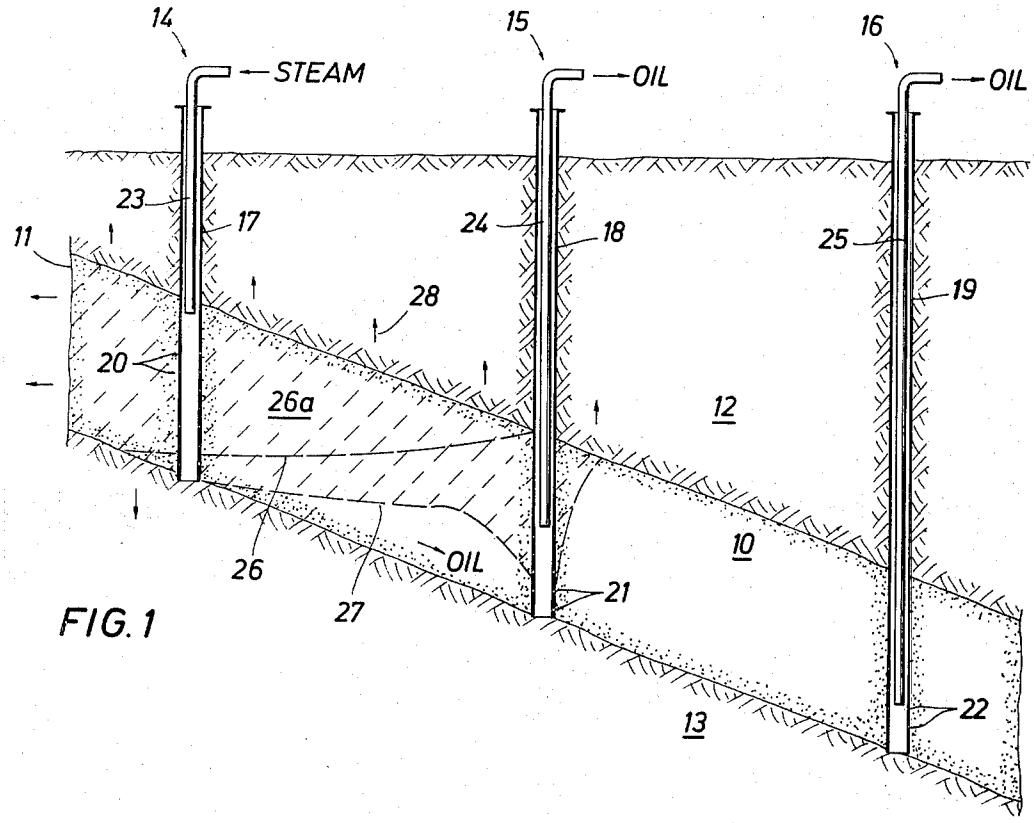

14
STEAM
15
OIL
16
OIL
23
17
24
18
25
19
11
28
20
26a
12
10
26
27
OIL
21
13
22

FIG. 1

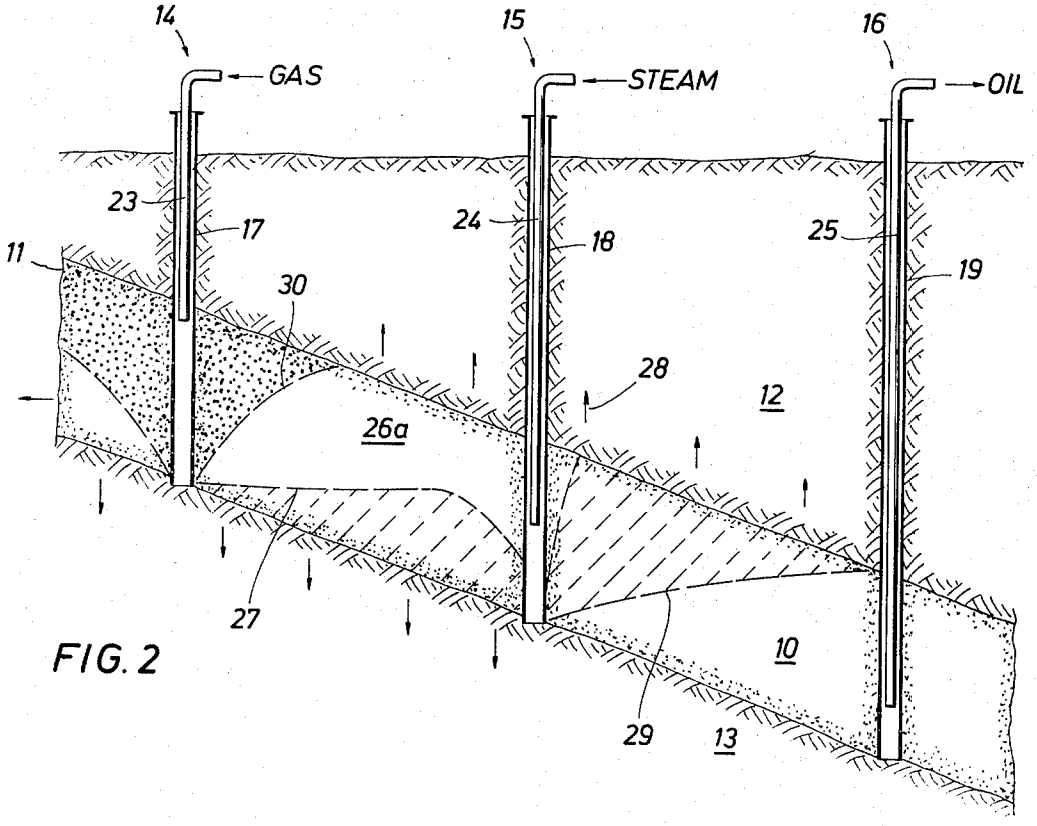

14
GAS
15
STEAM
16
OIL
23
17
24
18
25
19
11
30
28
12
26a
27
10
29
13

FIG. 2

STEAM DRIVE OIL RECOVERY PROCESS

BACKGROUND OF THE INVENTION

1. Field of the Invention

This invention relates to the field of producing oil through wells, and more particularly to an improved steam drive thermal recovery process.

2. Description of the Prior Art

In many areas of the world, reservoirs of low API gravity crude oil exists which are difficult to produce because the high viscosity of such low gravity oil makes it substantially immobile within the reservoir. It is well known that the viscosity of most crude petroleum is temperature dependent and that the viscosity of the oil in a given reservoir may be decreased by a factor often on the order of 50 to 1,000 times by an increase in the temperature of that oil on the order of 100°F. To this end, a number of methods for heating oil in a petroleum reservoir have been successfully employed. Among these is the injection of steam and/or hot water into the reservoir to heat the oil and to drive the heated oil to a producing well.

Steam stimulation may take the form of a steam drive in which steam is injected into a first well to drive heated oil to a second well from which fluid is produced. Another form of steam stimulation process is the soak or "huff and puff" process in which steam is injected into the oil-containing formation through a well for a period of time after which reservoir fluids are produced from that same well.

The economic success of a steam recovery process is dependent upon the ratio of the value of hydrocarbon liquids produced as a result of the steam treatment to the total cost of the steam treatment. Generally, the financial success of an operation is related to the ratio of barrels of oil recovered per barrel of steam injected. Projects with a high oil-to-steam ratio are for the most part more successful than projects with a low oil-to-steam ratio.

A major factor determining oil-to-steam ratio is heat loss from the thermally treated formation to adjacent earth formations above and below. If a large portion of the heat carried into the reservoir by a barrel of steam is lost to adjacent formations, this energy is not available to stimulate the production of oil from the thermally treated formation. This, of course, reduces the project oil-to-steam ratio.

It is known that the amount of heat lost from a steam zone surrounding a steam injection well to formations above and below the oil-containing formation is related to the area of contact between the steam zone and these adjacent formations. As the steam zone becomes large, the amount of heat lost to these adjacent formations becomes sufficiently great to adversely affect project efficiency. Thus, it is generally desired to keep steam zones as small as possible while still heating a large amount of the reservoir. For this reason, it has been the practice in most steam drive recovery projects to use pattern floods, for example five-spot or seven-spot patterns, of the type in which steam is driven from a number of peripheral wells to a relatively close centrally located well as opposed to using a line drive type flood pattern in which steam is driven from one side of an oil-containing reservoir across that reservoir to the other side. However, the line drive method is often the most efficient method from a percentage of oil recovered view point, especially in a dipping reservoir in which the line drive is designed to work in concert with natural gravity forces.

SUMMARY OF THE INVENTION

We have now discovered a method for producing oil from a dipping, viscous-oil containing subsurface earth formation using a line drive type recovery pattern without incurring excessive heat losses across the boundaries of the formation by providing at least three spaced wells which intersect and are in fluid communication with the formation, the second of these wells being down-dip from the first of the wells and the third of the wells being down-dip from the second. Steam is first injected into the formation through the first, up-dip, well to drive oil through the formation toward the down-dip second and third wells while simultaneously producing oil from the formation through the second and third well. This injection of steam into the up-dip well and production from the down-dip wells is continued until steam breaks through into the second well. Thereafter, injection of steam into the first well and production of oil from the second well are stopped. A non-condensing gas is then injected into the first well. Simultaneously, steam is injected into the second well to drive oil through the formation toward the third well and production is continued from the third well. In one preferred embodiment the non-condensing gas is one less dense than steam vapor, or stated another way, is a gas having a molecular weight less than 18.

Advantageously, the non-condensing gas in injected into the first well at a volumetric rate sufficient to maintain that portion of the formation contacted by steam injected through the first well substantially free from steam injected into the formation through the second well. Of course, there will be some invasion of the previously steamed zone in the immediate vicinity of the second well. Preferably, the non-condensing gas is injected at a pressure and rate such that this gas fills the portion of the reservoir previously contacted by steam with gas at a pressure substantially equal to the steam pressure as steam in this portion of the formation condenses due to heat loss to adjacent strata.

The non-condensing gas is preferably not injected at rates high enough to significantly raise the fluid pressure in the formation since this will increase the temperature at which aqueous fluid must be injected into the formation if the fluid is to be in the vapor phase. Such an increase in temperature results in additional expense for heating the aqueous fluid prior to injection.

The method may be practiced as a first thermal stimulation process in a particular reservoir or after other stimulation projects have been initiated. It may be particularly advantageous to first steam soak the injection and producing wells using one or more cycles of a huff and puff type process to heat the reservoir and loosen the oil contained therein prior to initiating the steam drive.

In one embodiment of the invention a foaming agent is injected into the up-dip injection well after the termination of steam injection in that well and before the commencement of non-condensing gas injection in order to provide a foam barrier between the steam zone and the non-condensing gas zone. This reduces the probability of non-condensing gas breakthrough into producing wells.

It also may be desirable in some cases to inject water into the second well while continuing to inject non-condensing gas into the first well after steam breakthrough from the second well to the third well in order to scavenge heat from the formation and to drive oil to the third well and/or to other wells further down-dip.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a sectional view of a dipping subsurface earth formation penetrated by three wells.

FIG. 2 shows the subsurface earth formation in FIG. 1 at a time after gas injection has been commenced near the top of the formation according to the teachings of this invention.

DESCRIPTION OF PREFERRED EMBODIMENTS

Referring to FIG. 1 we see a sectional view of a dipping earth formation **10**. The formation **10** contains viscous hydrocarbon liquids which may be mobilized upon heating. Formation **10** is sealed to fluid flow along its up-dip boundary by an impermeable barrier such as fault line **11** and is bounded above and below by adjacent formations **12** and **13**, respectively. Three wells, **14**, **15** and **16**, are shown intersecting the formation **10** in the plane of FIG. **1**. It should be understood that the wells **14**, **15** and **16** may represent rows of wells similarly situated along the dip of the formation **10**. In the line drive method of this invention, the wells of each row are preferably treated in substantially the same way as the respective wells **14**, **15** and **16**.

According to the method of this invention, steam is injected into the up-dip well **14** to drive oil to the down-dip wells **15** and **16**. To this end, each of the wells is completed with suitable equipment of a known type. For example, the wells may be provided with tubular casings **17**, **18** and **19**, respectively, which are cemented in place and perforated adjacent the formation **10** to open the interior of the casings into fluid communication with the formation. The perforations **20** of the up-dip well **14** preferably are spaced throughout the interval of the casing **17** adjacent the upper half of the formation **10** and may extend throughout substantially the entire interval of the casing **17** adjacent the formation **10** as shown. Advantageously, the perforations **21** and **22** of the down-dip producing wells **15** and **16**, respectively, are confined to the lower half of the formation **10**.

Up-dip well **14** may be provided with an injection tubing string **23** for carrying steam from the surface to a point in the well **14** adjacent the formation **10**. Correspondingly, production wells **15** and **16** may be provided with tubing strings **24** and **25**, respectively, for carrying produced fluids to the surface. Fluid lift means such as down hole pumps (not shown) may be associated with these production tubing strings **24** and **25**.

Steam from a surface steam generator (not shown) is injected down well **14** and into the formation **10** to heat the formation and the fluids therein, thereby mobilizing the viscous hydrocarbon liquids. Steam is preferably injected at a pressure and rate selected to achieve maximum benefit from the steam drive project per unit of energy expended in generating steam at the surface. A high injection rate may not be preferred since the attendant high pressures will raise minimum steam temperature and thereby increase surface energy requirements.

Because the steam is less dense than the liquids originally present in the formation **10**, the steam will tend to rise to the top of the formation and the mobilized oil will tend to flow to the bottom of the formation due to normal gravity forces. Thus, the steam may advance through the reservoir with a substantially horizontal front as shown by line **26** of FIG. **1**.

Concurrently with the injection of steam through up-dip well **14**, reservoir fluids are produced through down-dip wells **15** and **16**. As the front of injected steam approaches the first down-dip producing well **15**, steam will eventually be drawn down into the perforated interval of the well **15**. Line **27** of FIG. **1** represents the position of the steam front at this time.

Once steam has broken through into well **15**, the producing efficiency of that well becomes greatly reduced. Therefore, it is advantageous at this time to stop fluid production from the down-dip well **15** adjacent the injection well **14** and to start injecting steam into this well to drive oil toward producing well **16**. After steam injection is begun into well **15**, portions of the formation **10** heated by steam injected through the up-dip well **14** (e.g., zone **26***a* of FIG. 1) continue to lose heat by conduction to adjacent formations **12** and **13**. Such heat losses are particularly great across those portions of the boundaries of formation **10** contacted by steam. Arrows **28** in the figures represent the heat loss across these portions of the boundaries of formation **10**.

As heat passes from the steam zone **26***a* across the boundaries of the formation **10** into adjacent formation **12** and **13**, steam in this zone **26***a* condenses with an attendant substantial drop in the fluid pressure within the zone **26***a*. At least some of the steam injected into the down-dip well **15** will move up-dip into the previously steamed zone **26***a*, rather than down-dip toward producing well **15**, in response to this reduced pressure if no fluid is injected into well **14** to maintain the pressure in the steam zone **26***a* surrounding that well. However, if steam injection into the up-dip well **14** is continued, the thermal efficiency of the steam drive process is reduced because a substantial portion of the energy required to generate this steam is utilized in the formation **10** to replace energy lost by conduction to formations **12** and **13** rather than to further stimulate oil recovery.

We have found that it is, therefore, advantageous to inject a noncondensing gas into the up-dip well **14** to maintain the pressure in the zone **26***a*. A "non-condensing" gas is a gas which will not condense at conditions of temperature and pressure expected to exist in the formation **10**. In a preferred embodiment, this non-condensing gas is one having a density less than the density of steam at formation conditions of temperature and pressure (.e.g., helium, methane, or other gas or mixture of gases having an average molecular weight less than **18**).

The non-condensing gas is preferably injected into the up-dip injection well **14** at a volumetric rate sufficient to fill the reservoir volume vacated as steam in the zone **26***a* condenses due to heat lost by conduction to adjacent formations. Advantageously, this is achieved by regulating the rate of gas injection as required to maintain formation pressure in the zone **26***a* contacted by steam injected from the first well substantially constant.

It is undesirable to inject an amount of non-condensing gas which will cause the pressure in the zone **26***a* and other portions of the formation **10** to rise substantially since this would increase the temperature required to maintain steam of a given quality in the formation. This increases the surface energy requirements for carrying out the steam drive process. Thus, it is generally not desired that the injected non-condensing gas drive steam toward the producing well **16** to the extent that this would result in an increase in reservoir temperature. However, it may be advantageous to advance the non-condensing gas through the formation **10** at a rate substantially equal to the net rate of diffusion and convection of steam into the portion of the formation occupied by non-condensing gas. This rate may be measured experimentally or may be estimated mathematically.

If the injected non-condensing gas is of density less than the density of steam, as is preferred, then this non-condensing gas will tend to rise to the top of the formation and steam will tend to move to the bottom of the formation as shown in FIG. **2**. This will have beneficial result of insulating the top boundary of the formation. Such insulation reduces conductive heat losses to adjacent formation **12** and, thus, minimizes the injected non-condensing gas requirements since steam condensation in the formation **10** is thereby reduced.

The steam injected into the down-dip well **15** will advance down-dip through the reservoir in the same manner as steam formerly injected through the up-dip well **14**. This movement is illustrated in FIG. **2** which shows the boundary of the steam zone **26***a* at the time of commencement of steam injection into the well **15**, line **27**, as well as the lower boundary **29** of an enlarged steam zone after a period of steam injection into the well **15**. Zone **30** is occupied by non-condensing gas injected through the up-dip gas injection well **14**.

Preferably, the rate of steam injection into the well **15** is reduced with respect to the original rate of steam injection into the up-dip well **14** in proportion to the reduction in produced fluids volume due to the loss of intermediate well **15** as a producing well. This enables the steam drive process to be continued at substantially the same reservoir pressure as during the period of steam injection into the up-dip well **14**. As noted above, this pressure was selected as being an efficient one for the purposes of benefit derived per unit of energy expended in generating steam at the surface.

It may be desirable in some cases to inject a stable foam comprising a foamed mixture of non-condensing gas and a foaming agent, such as "OK Liquid," a modified ammonium akyl sulfate and organic builder manufactured by the Procter and Gamble Company, or other surfactant capable of maintaining a substantially stable foam in the formation **10** at the existing formation temperature, into the up-dip injection well **14** after the end of the initial period of steam injection into that well and prior to the injection of non-condensing gas. This foam is preferably injected in a volume sufficient to maintain a coherent foam bank in the formation between the non-condensing gas and steam. The foam will reduce mixing of non-condensing gas and steam with the beneficial effect of confining steam to portions of the formation down-dip from that occupied by the non-condensing gas. The non-condensing gas occupied volume is then removed from the portion of the formation in which pressure is dramatically reduced as heat is lost due to the condensation of steam.

Foam injection is particularly advantageous where the density difference between the non-condensing gas injected and steam is minimal or where the non-condensing gas is a gas more dense than steam i.e., carbon monoxide). The foam may be generated prior to injection into formation **10** or may be generated in situ by alternate injection of slugs of foaming agent and the non-condensing gas.

It may also be desirable in some cases to inject water into the intermediate injection well **15** after a period of steam injection to scavenge heat from the reservoir and carry this heat downward through the formation **10** towards the producing well **16**. During the injection of water into the well **15**, non-condensing gas injection into up-dip well **14** is continued at a rate sufficient to prevent substantial up-dip migration of injected water.

While the method of this invention has been particularly described with respect to a line of three wells **14**, **15** and **16**, it should be understood that the method can be advantageously extended to other wells down-dip from well **16** in formations traversed by such additional wells. In those formations, after steam breaks through into the second down-dip well **16**, injection of steam through first down-dip well **15** is stopped, steam injection through well **16** is commenced, and a non-condensing gas is injected into well **15** in addition to up-dip well **14**. Production of oil is continued through the additional wells (not shown) down-dip from new injection well **16**.

We claim as our invention:

1. An improved method for producing oil from a dipping, viscous-oil containing, subsurface earth formation comprising the steps of:

providing at least three spaced wells which intersect and are in fluid communication with the formation, the point of intersection of the second of the wells with the formation being down-dip from the point of intersection of the first of the wells with the formation and the point of intersection of the third of the wells with the formation being down dip from the point of intersection of the second of the wells with the formation;

injecting steam into the formation through the first well to drive oil through the formation toward the second and third wells;

producing oil from the formation through the second and third wells while simultaneously injecting steam through the first well;

continuing to inject steam through the first well and to produce oil through the second and third wells until steam breakthrough into the second well;

thereafter, stopping the injection of steam through the first well and the production of oil through the second well; and then

injecting a non-condensing gas into the formation through the first well;

injecting steam into the formation through the second well to drive oil through the formation toward the third well; and

continuing to produce oil from the formation through the third well.

2. The method of claim 1 wherein the non-condensing gas is a gas less dense than steam at formation conditions of temperature and pressure.

3. The method of claim 2 wherein the non-condensing gas is methane or helium.

4. The method of claim 1 wherein the non-condensing gas is injected into the first well at a volumetric rate sufficient to maintain that portion of the formation contacted by steam injected into the formation through the first well substantially free from steam injected into the formation through the second well.

5. The method of claim 1 wherein a zone of non-condensing gas is formed adjacent the first well;

wherein steam advances into this zone of non-condensing gas down-dip from the first well;

wherein the non-condensing gas is injected into the formation through the first well at an injection rate sufficient to advance the zone of non-condensing gas through the formation; and including the steps of:

determining the rate of advance of steam into the zone of non-condensing gas; and

injecting non-condensing gas into the formation through the first well at an injection rate selected such that the rate of advance of the non-condensing gas through the formation is substantially equal to the rate of advance of steam into the zone of non-condensing gas.

6. The method of claim 1 including the step of injecting a stable foam into the formation through the first well after the initiation of steam injection through the second well.

7. The method of claim 6 wherein the non-condensing gas is carbon monoxide.

8. The method of claim 1 including the steps of:

stopping the injection of steam through the second well after a period of steam injection through the second well;

injecting water into the formation through the second well to scavenge heat from the formation and to drive oil through the formation toward the third well;

continuing to produce oil from the formation through the third well; and

continuing to inject non-condensing gas into the formation through the first well.

9. The method of claim 1 including:

the step of prior to the injection of steam into the formation through the first well to drive oil to the second and third wells, steam soaking the formation, to mobilize fluids therein, through one or more steam soak cycles each cycle comprising the steps of

injecting steam into the formation through the first, second and third wells for a selected period of time; and

thereafter, producing fluid from the formation through the first, second and third wells for a second selected period of time.

* * * * *