March 19, 1968 T. C. BOBERG ET AL 3,373,805

STEAM LIFTING OF HEAVY CRUDES

Filed Oct. 14, 1965 2 Sheets-Sheet 1

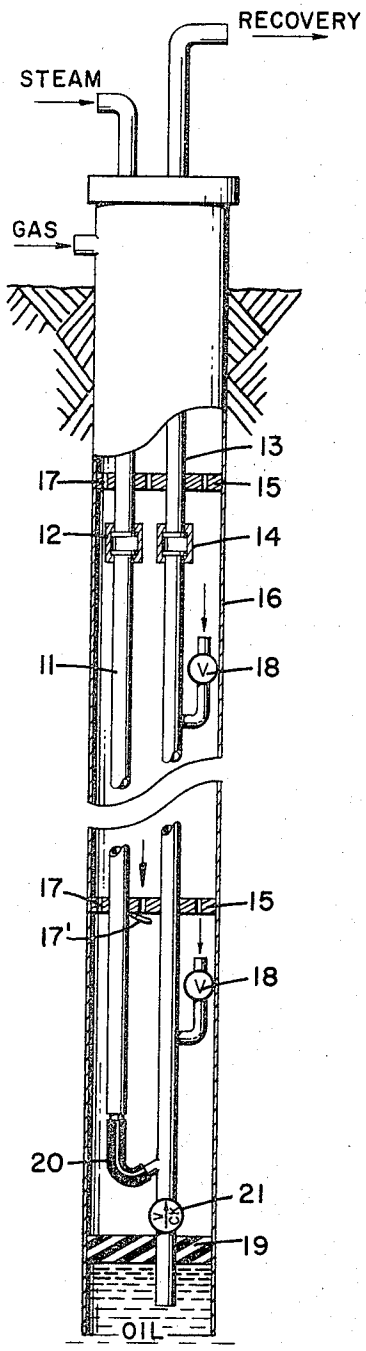


FIG. - 1

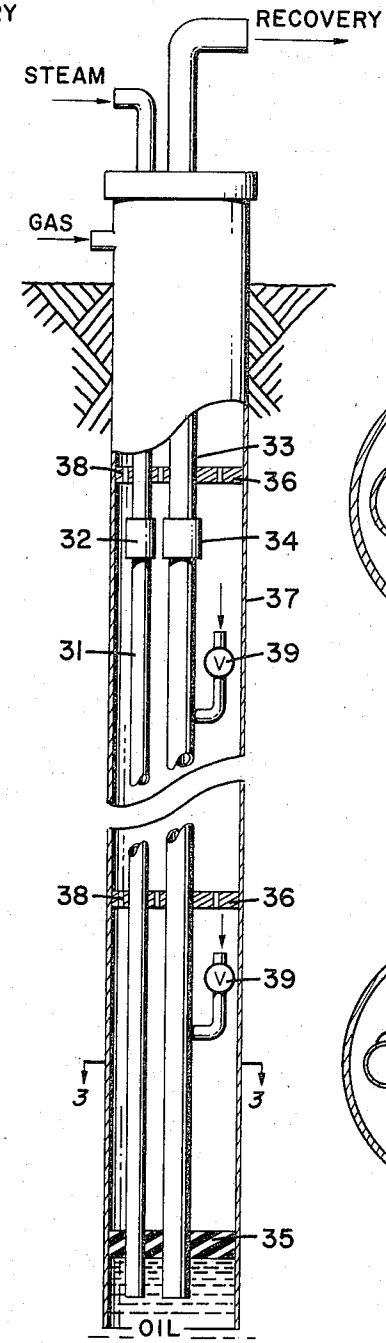


FIG. - 2

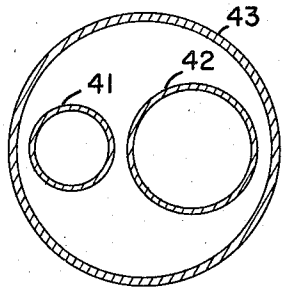


FIG. - 6

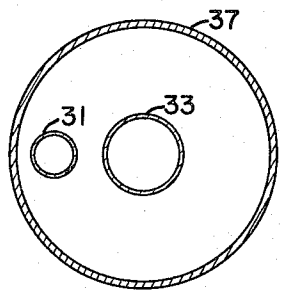


FIG. - 3

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STEAM LIFTING OF HEAVY CRUDES

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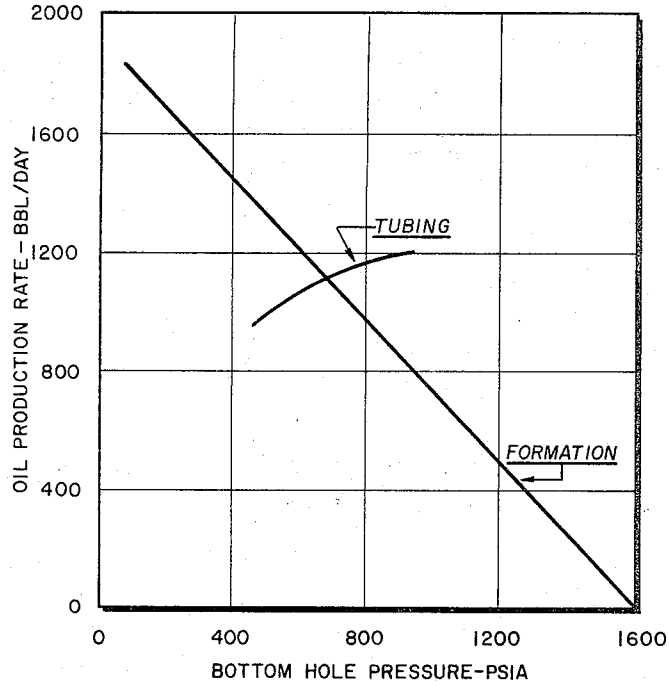


FIG.—4

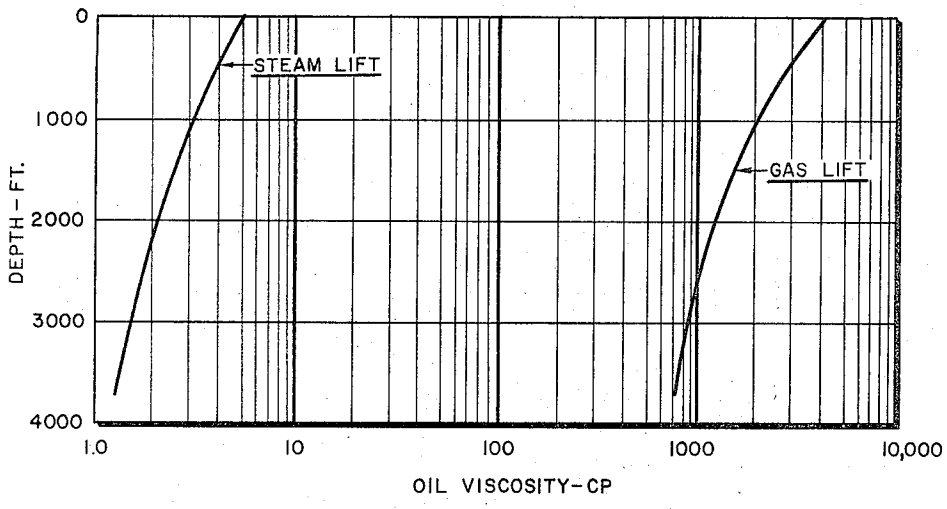


FIG.—5

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STEAM LIFTING OF HEAVY CRUDES

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11 Claims. (Cl. 166—2)

ABSTRACT OF THE DISCLOSURE

A combined gas lift-steam lift assembly and method for producing petroleum wherein the flow of petroleum is initiated by lifting the petroleum with natural gas and steam is injected into the production tubing to continue and increase the flow of petroleum.

This invention relates to the production of viscous petroleum crudes. A method and apparatus are provided for lifting viscous oil from the bottom of a wellbore to the surface of the earth. More particularly, the invention relates to improvements in the use of steam as a lifting medium for the production of viscous crudes.

A major problem in the production of viscous crude is the loss of efficiency which results from an unusually pronounced pressure gradient which develops in the production tubing due to the flow resistance caused by viscous friction. The high pressure drop in the production tubing leads to a reduced formation pressure drawdown and consequent low rates of oil production from the reservoir.

It has been recognized for many years that the application of heat is a possible solution to the problem, since the viscosity of most heavy crudes is sharply reduced by only moderate heating. Although moderate heating is sufficient, the practical success of any heating scheme is heavily dependent upon the need to provide an effective vertical distribution of the heat throughout the entire length of the wellbore.

It has been proposed to substitute steam in a conventional gas-lift operation. It can readily be shown, however, that the mere substitution of steam for gas in a conventional operation is ineffective due to permature steam condensation. The condensation problem would be acute not merely during the initial stages, but would soon cause a failure of the process even if the wellbore were initially heated to the temperature of steam in equilibrium with condensate.

Accordingly, it is an object of the present invention to utilize steam effectively in the lifting of viscous crudes. It is a further object of the invention to provide a procedure for utilizing steam in the lifting of viscous crudes to accomplish moderate heating of the full length of the wellbore. Friction losses due to viscous flow up the production tubing string are substanially reduced, thereby permitting increased formation drawdown pressures and increased rates of oil recovery.

It is a further object of the invention to provide a novel wellbore completion assembly which is particularly suited to the use of steam-lifting procedures. Still further, it is an object of the invention to provide a novel procedure for initiating steam lift.

The invention is based in part upon a discovery that the downflowing steam must be thermally isolated from the wellbore walls, and from the upflowing mixture of

steam condensate and formation fluids. Accordingly, two tubing strings are required; one for the downflowing steam and the other to contain the upflowing mixture. A "dead gas" space is maintained between the tubing strings from each other and from the surrounding earth, to prevent excessive condensation of the injected steam. It is essential in most wells to provide tubing strings having substantially different diameters. The steam is injected through the smaller diameter string and the produced fluids are lifted through the larger diameter string.

A mixture of steam and non-condensable gas is a particularly useful lifting medium in some circumstances—for example, where the produced fluids contain a low proportion of formation gas.

Since the method of the invention subjects the wellbore equipment to high temperatures, a warming-up period is frequently necessary to avoid extreme thermal stresses in the well casing and cement. In accordance with one embodiment, the process is initiated by first circulating hot water down the injection tubing and up the production tubing. Once the well has been warmed substantially—say, 50° to 60° F., gas is injected down the annulus and into the production string through gas lift valves in the conventional manner for initiating production from gas lift wells. The circulation of hot water through the tubing strings is continued, in combination with gas lift by gas injection down the annulus. Heat input to the steam generator is gradually increased until the hot water circulation is replaced by steam circulation. Gas injection is then gradually discontinued and the well is thereby converted to steam lift.

In accordance with a further embodiment of the invention, steam lift is combined with steam stimulation. Steam injection rates normally required for stimulation greatly exceed the injection rates required for steam lifting. Accordingly, for the purpose of stimulation, steam is injected through the larger of the two tubing strings. However, both tubing strings of the well completion assembly may also be utilized for the injection of steam. A typical stimulation program requires the injection of steam at 10,000–50,000 lbs. per hour for 1–8 weeks, followed by a production cycle lasting from 3 to 20 times as long as the injection period, depending upon reservoir conditions and the flow rates of the produced fluids. Converting back to steam lift, after having stimulated the well by injecting steam through both tubing strings, requires no intermediate steps; the production string is simply disconnected from the steam boiler output and again diverted to separation facilities for the normal processing of produced fluids.

Actually, a thermally stimulated well sometimes needs little or no artificial lifting for an initial period of several days or weeks, due to the oil viscosity reduction and increased productivity resulting from steam injection. A continued flow of steam through the injection tubing at a minimum rate may be desirable, however, from the standpoint of keeping the injection tubing hot in order to facilitate a transition back to steam lift. A more detailed explanation of steam stimulation procedures is found in a copending application of Thomas C. Boberg, U.S. Ser. No. 178,399, filed Mar. 8, 1962, and now abandoned.

FIGURE 1 represents a vertical cross-section of the earth, showing a suitable well completion assembly for use in accordance with the invention.

FIGURE 2 also represents a vertical cross-section of

the earth, showing an alternate well completion assembly for use in accordance with the invention.

FIGURE 3 is a horizontal cross-section along line 3—3 of FIGURE 2, which illustrates a suitable tubing-casing geometry for use in accordance with the invention.

FIGURE 4 illustrates a determination of the oil production rate which can be achieved in accordance with one embodiment of the invention, as applied to a specific reservoir.

FIGURE 5 is a graphic comparison of the oil viscosity as a function of depth for a conventional gas lift well with that for a well using the method of this invention, as applied to a specific reservoir.

FIGURE 6 is a horizontal cross-section of a preferred tubing-casing geometry for use in accordance with the invention.

Referring to FIGURE 1, the illustrated completion assembly includes injection tubing string **11** equipped with a thermal expansion joint **12**; and production tubing **13**, equipped with a thermal expansion joint **14**. At various depths within the borehole, spacing members **15** which bridge the annulus are mounted on the tubing strings in order to reduce convection within the annulus and hence minimize heat transfer from one tubing string to the other, and between the tubing strings and the casing. The spacing members are provided with one or more openings or ports **17** to permit the passage of injected gas during the start-up procedure. Ports **17** are preferably provided with check valves or equivalent means to reduce convection currents after the injection of gas has ceased. One such check valve is shown schematically at **17'**. Production tubing **13** is equipped with a series of valves **18**, ejectors or the like, similarly as are used in conventional gas lift equipment. A thermal packer **19** is provided near the lower end of the tubing strings in order to contain formation fluids and injected steam therebelow. A flexible, heat-resistant hose **20** connects tubing **11** and **13** to allow for unequal thermal expansion of the two tubing strings. A check valve **21** is located in a lower portion of tubing **13** to prevent the injection of fluids into the formation during start-up. In accordance with a further embodiment, check valve **21** is equipped with means for permitting reverse flow, whenever desired, for example, in the use of both tubing strings for steam stimulation of the reservoir.

In operation, steam is injected through tubing **11** and into production tubing **13** at an upwardly directed angle. This geometry minimizes the erosive effect that entrained steam condensate droplets have as they impinge on the tubing wall opposite the point of entry.

FIGURE 2 shows an alternate well completion assembly for use in practicing the invention, which includes injection tubing **31** equipped with a thermal expansion joint **32**; and production tubing **33** equipped with a thermal expansion joint **34**. A heat-resistant packer **35** is installed, for thermal efficiency, to confine the produced fluids and injected steam to the lower portion of the borehole. Centralizer baffles **36** are installed at various intervals of depth to thermally isolate the tubing strings from each other and from casing **37**, and to minimize convective currents in the "dead gas" space. Openings **38** in the centralizer baffles are provided for the passage of injected gas during start-up. Similarly as in the embodiment of FIGURE 1, a plurality of pressure-actuated valves **39** are spaced along production tubing **33** to permit an initial start-up procedure as previously described.

A low-cost alternative to the completions in FIGURES 1 and 2 would be a completion which consists of two tubing strings hanging free in the casing, omitting the packer, gas lift valves, expansion joints, and centralizer beffles. Gas would be injected at a low rate into the annulus to keep liquid out of the annulus and maintain insulation. This completion would not be as thermally efficient as the two described above and would necessitate having boiler pressure in excess of static downhole formation pressure for start-up.

FIGURE 3 illustrates the relative diameters of the casing and the two tubing strings of the embodiment of FIGURE 2. The purpose of unequal tubing diameters is twofold: (1) The smaller tubing is the injection tubing, thereby reducing the radiating area which reduces heat losses; and (2) the smaller injection tubing allows a larger production tubing, thereby increasing the production capabilities of the well. The diameter of the production tubing is preferably at least 20% greater than the injection tubing diameter and may be 100% greater or more.

The data plotted in FIGURE 4 represents an example of the invention involving the production of oil having a gravity of 10° API at 60° F., from a depth of 3700 ft. The dead oil has a viscosity of 16,000 cp. at 100° F. and 190 cp. at 210° F. The productivity index (bbls./day/p.s.i.) of the well is 1.2 and the reservoir pressure is 1600 p.s.i.a. The formation is producing water-free oil containing 68 s.c.f. of gas per barrel.

The "formation" curve represents the oil production rate of the formation plotted as a function of bottom hole pressure. The "tubing" curve is a plot of the rates at which oil can be lifted through a four-inch tubing, in accordance with the invention, by the injection of 300 bbls./day of steam (expressed as liquid at 60° F.) through a two-inch tubing, as a function of bottom hole pressure. The intersection of the two curves corresponds to a bottom hole pressure of 680 p.s.i.a. and an oil production rate of 1120 bbls./day. This production rate is achieved with a wellhead pressure of 200 p.s.i.a. This represents a 55% increase over the production rate which can be obtained under similar circumstances with conventional gas lift, injecting at one million s.c.f./day.

Steam lifting in accordance with the invention is not always superior to gas lifting, nor is it always superior to the use of a conventional pump. Steam lifting is particularly suited, however, for the production of oil having an API gravity below 15° from a well having a static bottom hole pressure in excess of about 800 p.s.i.a and a productivity index of about 3 bbls./day/p.s.i. These parameters have been empirically correlated to provide a generalized guide for determining whether the method of the invention is well-suited for use in specific situations, as follows:

$$J(P-500)\geq 50\ (^{\circ}\text{API})$$

where

J=productivity index, bbls./day/p.s.i.

P=static formation pressure, p.s.i.a.

° API=gravity of crude, API degrees

This correlation holds best for wells in the 2000–5000 ft. depth range. A similar correlation can readily be determined for other wells. It is to be understood that this relationship does not account for all circumstances which may affect the efficiency of the process, but it is nevertheless a very useful approximation.

In the above example illustrated by FIGURE 4, the productivity index of the well can be greatly increased by the use of steam stimulation, preferably in combination with steam lift. For example, the injection of steam into the reservoir at a rate of 50,000 lbs./hr. for 25 days results in a 1000 bbl./day peak increase in the rate of oil production.

FIGURE 5 is a comparison of the viscosity profiles obtained during steam lifting and during a normal gas lift operation, as applied to the same reservoir and the same well completion assembly as described in connection with FIGURE 4. As shown, steam lifting achieves about a thousandfold reduction in crude viscosity over that obtained with gas lift. This reduction in viscosity is the principal advantage which the present invention has over gas lift or pumping.

In FIGURE 6, the tubing-casing geometry of a preferred well-completion assembly is shown. Steam is injected through tubing **41**, and fluids are produced through tubing **42**. In this embodiment, neither tubing string is

centralized within the casing. In this configuration, it is possible to maximize the combined cross-sections of the tubing strings, within the limits of casing 43, while at the same time maintaining a sufficient "dead gas" space between the tubing strings, and also between the casing and each tubing string.

In general, the steam injection tubing should be sized as small as possible, consistent with the requirement that the necessary steam injection rate be maintained with a reasonable pressure drop from the wellhead to bottomhole. Having thus selected the injection tubing size, the space remaining within the casing diameter must be sufficiently large to permit the use of a production tubing string substantially larger than the injection tubing.

A wide range of steam quality is suitable for use in accordance with the present invention, although it is to be expected that each well and each reservoir may require a different steam quality for optimum results. It is within the scope of the invention to employ superheated steam, dry saturated steam, or wet saturated steam having a quality in the range of about 30–100%.

In accordance with a further embodiment of the invention, a water-wetting agent is included with the injected steam. The wetting agent further reduces friction losses in the production tubing since these losses occur mainly near the tubing wall and are therefore more dependent upon the water properties than upon the oil properties. Suitable water-wetting agents include anionic and nonionic surfactants. Specific examples are the ethoxylated dioctyl ester of succinic acid, sodium dioctyl sulfosuccinate, and isopropyl naphthalene sodium sulfonate. They should be injected in amounts ranging from 0.001 pound to 0.01 pound per pound of injected steam.

In accordance with a further embodiment of the invention, steam may be replaced as the lifting medium by a mixture of steam with a hydrocarbon vapor, including propane, butane, naphtha, kerosene, or other light petroleum fractions. When using such mixtures it is essential, as with steam alone, to minimize heat transfer between the downflowing and upflowing streams, and to minimize heat transfer between each tubing string and the wellbore wall. Similarly, the steam may be replaced altogether by a hydrocarbon vapor—for example, one or more of the above-named hydrocarbons.

A particularly preferred scheme for utilizing the method of the invention to produce offshore wells involves the drilling of several wells from a single, centrally located platform. For example, the drilling of a seven-spot pattern may include a single straight hole bottomed substantially directly below the platform, surrounded by six deviated wells. In addition to the wellhead equipment, the platform carries steam generators, water-treating equipment, gas compressors, heat exchangers, separators, storage tanks, and manifolds, plus the necessary instrumentation. The steam generators are operated continuously at full load, while the steam is distributed to each well for stimulation and for steam lift purposes. In the case of a seven-spot pattern, for example, only one well at a time may require stimulation, while the remaining six wells are receiving steam for lift purposes. The water-treating equipment preferably comprises an ion-exchanger, regenerated using softened downflow from the steam generators. Fuel requirements are supplied solely from the gas produced with the oil, thus eliminating the necessity of supplying gas from extraneous sources.

What is claimed is:

1. A method for initiating the steam lifting of a viscous crude to the surface of the earth from a substantial depth within a wellbore which comprises circulating hot water within said borehole to the depth of said crude, in contact with said crude, and then back to the surface of the earth through a separately confined path, thereafter injecting gas down said borehole in a third path, commingling said gas with the upflowing stream of hot water at successively greater depths within said borehole, then gradually increasing the temperature of said hot water until the hot water is replaced by steam, and then gradually discontinuing the injection of gas, whereby steam lifting is accomplished.

2. A method as defined by claim 1 wherein said downflowing steam is confined to a path of substantially smaller diameter than said upflowing path.

3. A method for producing viscous crude from a porous subterranean reservoir which comprises drilling a well into the reservoir from the surface of the earth, completing the well with two laterally spaced-apart tubing strings, injecting steam into the well through one of said tubing strings, whereby the steam is commingled with fluids produced from the reservoir, flowing the commingled fluids to the surface through the other of said tubing strings, and periodically stimulating the well by injecting steam into the well through both of said tubing strings, thereby forcing the steam to penetrate the reservoir a substantial distance from the wellbore, then resuming production from the well at a stimulated rate.

4. A method for lifting viscous crude to the surface of the earth from a substantial depth within a borehole which comprises circulating steam containing a water wetting agent through said borehole in contact with the crude and back to the surface of the earth whereby the petroleum is entrained and lifted with the steam and steam condensate, wherein the downflowing stream is thermally isolated from the upflowing stream, and each of said streams is thermally isolated from the wellbore wall.

5. A method as defined by claim 4 wherein said downflowing stream is confined to a substantially smaller diameter than said upflowing stream.

6. A well completion for steam lifting comprising first and second tubing strings, a plurality of spacing members engaging said strings to minimize heat transfer, and a plurality of valves vertically spaced along said second tubing string for providing fluid communication between the annulus and the inside of said second tubing string, wherein said spacing members are equipped with check valves permitting downflow to the substantial exclusion of upward flow.

7. In the production of oil from offshore locations, the method which comprises drilling a first wellbore substantially directly below the surface location, drilling a plurality of additional wellbores surrounding said first wellbore, said additional wellbores being deviated to a point of completion within the oil-bearing reservoir at a distance from said first well substantially greater than the surface distance between wells, completing each well with two laterally spaced apart tubing strings, injecting steam into each well through one of said tubing strings, whereby the steam is commingled with fluids produced from the reservoir, flowing the commingled fluids to the surface through the other of said tubing strings, and periodically stimulating each well in succession by injecting steam into the well through the production string, thereby forcing steam to penetrate the reservoir a substantial distance from the wellbore, then resuming production from each said well at a stimulated rate.

8. A combined gas lift-steam lift method for producing petroleum from a subterranean reservoir which comprises injecting gas into a wellbore in a first path to initiate the flow of petroleum through a second path and injecting steam through a third path in the wellbore and introducing the injected steam into the second path to increase the flow of petroleum within the second path.

9. The method as defined by claim 8 wherein the first path is the annulus of the wellbore, the second path is a tubing string and the third path is a tubing string of substantially smaller diameter than the second path.

10. A well completion for gas and steam lifting petroleum from a wellbore which comprises a tubing string for the production of petroleum; at least one gas lift valve disposed on the first tubing string and providing an entry for gas into the tubing string from the annulus between

the wellbore and the first tubing string; a second tubing string in fluid communication with the first tubing string for the introduction of steam; and at least one perforated spacing member engaging the first and second tubing string to minimize heat transfer and to permit the flow of gas within the annulus.

11. The well completion as defined in claim 10 further including at least one check valve in the spacing member to permit the downward flow of gas through the member and to substantially prevent upward flow.

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STEPHEN J. NOVOSAD, *Primary Examiner.*