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METHOD OF ASSISTING THE RECOVERY OF HYDROCARBONS USING A STEAM DRIVE

Filed Jan. 26, 1968 2 Sheets-Sheet 1

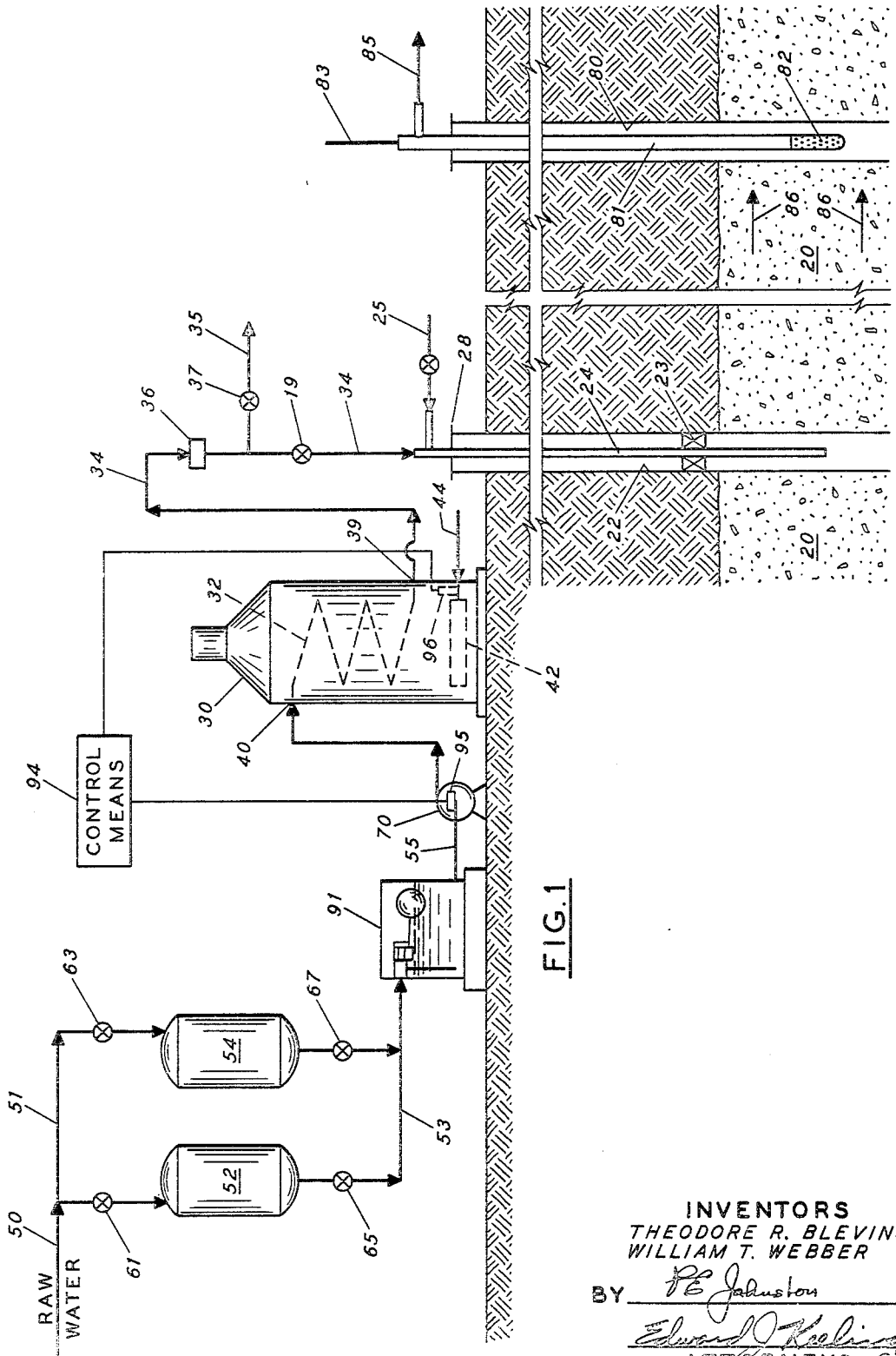


FIG. 1

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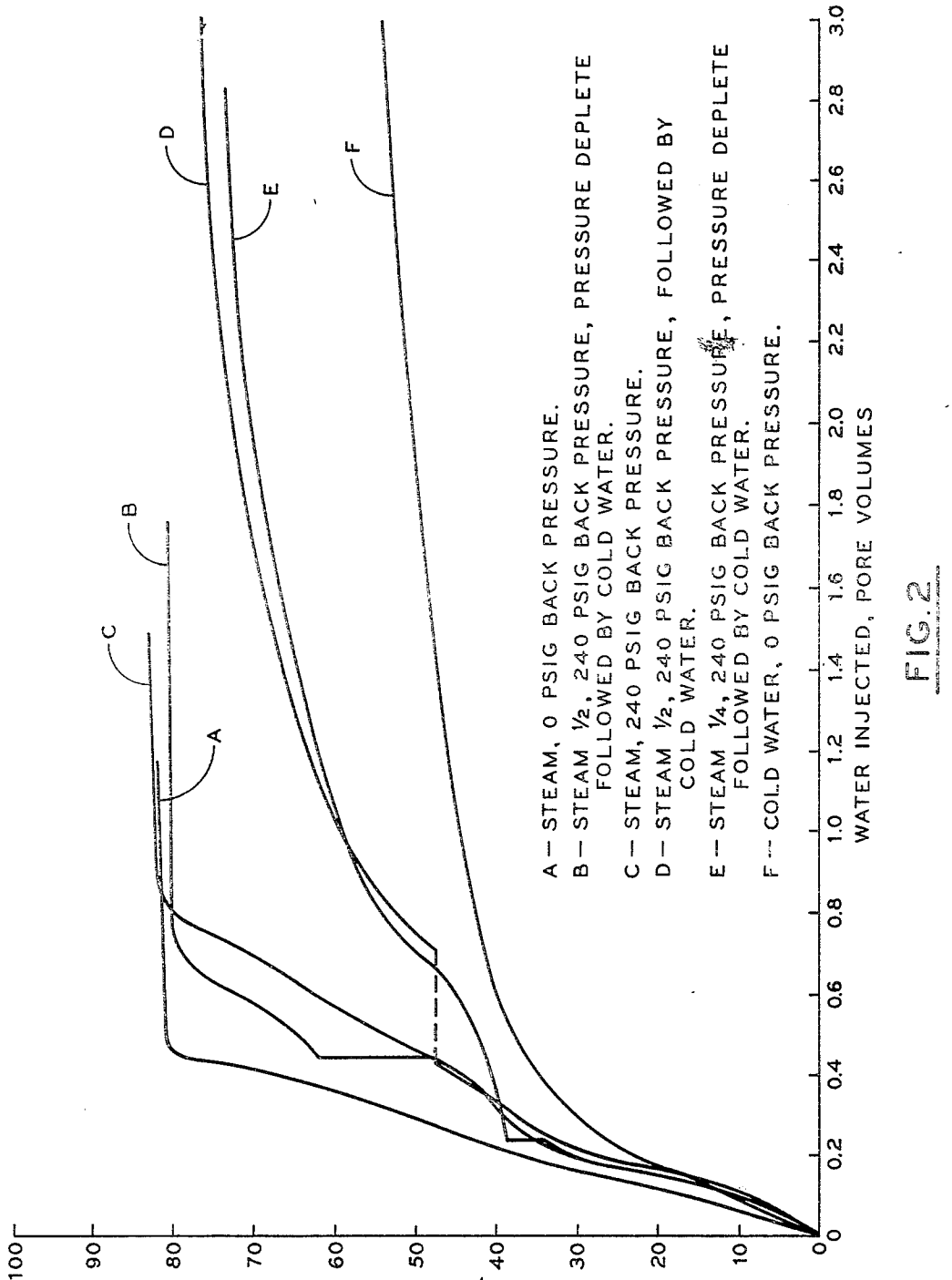


FIG. 2

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METHOD OF ASSISTING THE RECOVERY OF HYDROCARBONS USING A STEAM DRIVE

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U.S. Cl. 166—272 4 Claims

ABSTRACT OF THE DISCLOSURE

A method of improving hydrocarbon recovery from a hydrocarbon bearing formation by injecting steam through at least one injection well to establish a heat reservoir in the formation, halting said steam injection and producing oil from at least one production well penetrating said formation to reduce the pressure in said formation and then injecting water through at least one injection well into said formation to further assist in the recovery of hydrocarbons from said formation.

This invention relates to a method of improving the recovery of hydrocarbons from a hydrocarbon bearing formation penetrated by at least one injection well and at least one producing well and, more particularly, this invention relates to a method of improving hydrocarbon recovery by injecting steam into a formation penetrated by an injection well to establish a heat bank in the formation, then halting said steam injection and depleting the pressure in the formation by producing hydrocarbons from a production well penetrating the formation and then after the pressure depletion step injecting water into the formation through said injection well to further assist in the recovery of hydrocarbons from said formation.

Many methods have heretofore been utilized to assist in the recovery of oil from oil bearing formations. As is well known, primary recovery from many reservoirs amounts to less than 30 percent and often less than 10 to 15 percent of the available oil in place in the formation. Therefore, there is much need for improvement in the area of assisted recovery. The use of heat, particularly in the form of steam, while known in the art for some time, has only recently become a generally used technique for assisting oil recovery. One of the particular problems associated with steam flooding which has not been heretofore solved is how to make effective, economical use of the heat remaining in the reservoir after the injection of steam has been terminated. There is presently a need for a more effective and economical method of utilizing steam in the assisted recovery of petroleum.

In a broad aspect, the present invention is directed to a method of improving the recovery of hydrocarbons from a formation penetrated by at least one injection well and one production well. In accordance with the invention, a heat bank is established in the formation by injecting steam through an injection well and out into the hydrocarbon bearing formation. This steam injection stimulates production from the producing wells and forms a heat bank in the formation. After a sufficient amount of heat is transferred to the formation, injection of steam is halted. The injection well is then closed in. Production of hydrocarbons is continued at the production well preferably at as rapid a rate as possible to lower pressure in the formation. When the pressure in the formation has been decreased at least a minimum amount, water is injected through the injection well and out into the formation to establish a secondary steam drive in the formation to further assist in the production of hydrocarbons from the production well.

The present invention is particularly useful in assisting the recovery of hydrocarbons from relatively low pressure, partially depleted reservoirs. The pressure in the reservoirs in which the present method is most applicable is 1,000 p.s.i. or less. It is highly preferable that the static pressure in the reservoir be 500 p.s.i. or less and the best results can be expected in low pressure partially depleted reservoirs having static pressures of 100 p.s.i. or less.

In a more particular and especially economically advantageous aspect, the method of the present invention involves injecting steam into a reservoir through an injection well into a formation in an amount of from about 40 percent to 60 percent of the steam which would be required to breakthrough the formation to a production well. Thus, about one-half of the steam required for breakthrough is injected into the formation through the injection well. The amount of steam required in many instances to give a condition equal to 40 to 60 percent of breakthrough is equal to the amount of steam which is produced from an amount of feed water equivalent to between 15 percent to 20 percent of the available pore space of the reservoir in which steam is to be injected. After the predetermined amount of steam is placed in the reservoir, injection of steam is halted and the static pressure of the reservoir is reduced by rapid production of fluids from one or more production wells. The wells are kept pumped off so that a maximum amount of fluids may be removed from the reservoir. When at least enough fluids have been removed from the formation to cause the static pressure in the reservoir to fall at least 30 to 50 p.s.i. below the static pressure in the steamed out portion of the reservoir just prior to the termination of steam injection, water is injected through the injection well and into the formation. Water injection through the injection well is continued to assist in the recovery of additional hydrocarbons from the formation through the production well.

It is a particular object of the present invention to provide a method of improving recovery of hydrocarbons from a formation by initially establishing a heat bank in the formation, then pressure depleting the formation by production of fluids therefrom and finally injecting additional fluid into the formation and moving said fluid through said heat bank to continue to assist in the production of hydrocarbons from the formation. Further objects and advantages of the present invention will become apparent from the following detailed description read in view of the accompanying drawings which are made a part of this specification and in which:

FIGURE 1 is a view partially in section illustrating a preferred embodiment of the apparatus assembled in accordance with the present invention; and

FIGURE 2 is a graph having curves showing oil recovery versus pore volumes of injected fluid and compares method of the present invention with other methods.

Referring now to the drawings in FIGURE 1, in particular, the preferred embodiment of the apparatus assembled in accordance with the present invention is illustrated. While it is recognized that the method of the present invention can be accomplished using a variety of apparatus, it is preferred that the apparatus used in performing the method of the present invention be assembled in accordance with that illustrated in FIGURE 1. As shown in FIGURE 1, a producing formation **20** is penetrated by an injection well **22**. A flow tube **24** is arranged in the well **22** and provides a flow path for steam down the well to producing zone **20**. In most applications, it is desirable to have a packer **23** located above and close

to the producing formation **20**, or an inert gas column in the casing annulus.

At least one producing well **80** which also penetrates producing formation **20** is required in accordance with the present invention. In actual field operations the method of the present invention will generally utilize a large number of wells. The injection wells and the production well will be selected in accordance with a preplanned pattern. For example, 5-spot of 7-spot patterns would be useful in the present invention. In any event, each producing well **80** has suitable producing equipment such as a string of producing tubing **81**, the lower end of which contains a pump **82**. The production pump **82** is located adjacent producing formation **20** so that the pump may keep the well pumped off, i.e. keep the fluid level in the well at or below the producing formation. The pump is operated by means of sucker rods **83** which lifts oil to gathering line **85**. Arrows **86** indicate oil flow changes promoted in accordance with the present invention. This is caused initially by steam and then later by water injected into formation **20** through well **22**.

The surface equipment preferred for providing steam for injection into formation **20** includes a suitably sized once through boiler **30**. The boiler **30** is provided with steam generating tubes **32**. These tubes **32** are arranged in a once through flow arrangement. Appropriate piping **34** connects the outlet of the steam generating tubes to the downhole steam flow tube **24**. A flow bean, or appropriate valve **36**, is used to regulate steam flow into the well. A bleed line **35** having a suitable valve **37** should be provided above the wellhead **28**.

A source of raw water for making steam is illustrated by the number **50**. Most, if not all, of the water available for use in oil field operations contains ions of a scale forming nature such as calcium and/or magnesium. Water treating means, such as tanks **52** and **54**, are connected by suitable piping **51**, **53** and **55** for supplying treated water to the boiler **30**. Valves **61**, **63**, **65** and **67** are useful to control water flow through water treating tanks **52** and **54**. The water treating tanks preferably contained an ion exchange resin which converts the relatively insoluble calcium and magnesium salts to a relative soluble salt, such as the sodium salt, which will stay in solution and not cause undesirable scaling. Downstream of the water treating tanks **52** and **54** a reservoir **91** provides storage for extra treated water to insure that water will be available at the suction of the pump **70** used to supply the boiler **30**. A flow type reservoir which is activated by lowering of the water to open the upstream flow line **53** in the tank has been found to give good results.

In accordance with the present invention, the rate of water flow through coils **32**, or the heat provided by burner **42**, is adjusted to provide steam of a desired temperature and quality. The water content of the steam may vary; however, it is preferred that the amount of water in the steam be at least enough to maintain the sodium salts in solution and thus prevent excessive scaling in the boiler tubes or flow line to the well. Preferably, the steam should contain at least 5 percent water to insure that precipitation and scaling of the boiler tubes do not occur. This is of course dependent on the particular water which is being converted to steam.

In accordance with the invention, the temperature of the injected steam is maintained in excess of 230° F., and preferably at temperatures in the range of 250°–450° F. Temperatures exceeding about 500°–600° F. are normally not used. A control means **94** is utilized for controlling the heat provided by burner **42** or the amount of water moved by pump **70**, or both, to provide steam at a selected temperature. A speed regulator **95** on the pump may be activated by the control means to vary the amount of water flowing into the boiler. A valve **96** may, for example, be controlled by the control means to adjust the amount of fuel gas or fuel oil flowing into the burner. Thus the temperature of the steam leaving boiler **30** at exit **39** may be controlled as desired.

The steam is injected into the formation through an injection well. Usually the injection and production wells will be arranged in a repeated pattern over a field. As is well known in the art, 5-spot or 7-spot patterns are often used. In a 7-spot arrangement, for example, a centrally located well may be used as an injection well and six peripherally spaced wells are used as production wells. If desired, the arrangement may be reversed with the six outside wells serving as injection wells and the single central well being used for production of oil. The present invention is not tied to any particular arrangement of wells, and generally speaking good engineering practice and prior development of the field will determine well spacing for use in the present invention.

Steam is injected into the formation in an amount sufficient to establish a substantial heat bank in the formation. It has been found that particularly economical and efficient recovery can be realized if the amount of steam injected through the injection well is between about 40 percent and 60 percent of the amount of steam which would be required to cause breakthrough of the steam into the producing well or wells. Thus, it is highly preferred to inject about one-half the amount of steam into the formation through the injection well which would cause breakthrough of the steam into the producing well. The amount of steam needed to achieve breakthrough will vary according to characteristics of individual formations. However, the amount of steam required for breakthrough in many reservoirs in which the method of the present invention is most applicable is about the amount of steam which is produced by vaporizing an amount of water equivalent to 35 percent of the pore volume of the formation which is to be flooded. Thus, as a general rule the amount of steam to be injected into a formation is an amount which is produced from a volume of feed water equivalent to 15–20 percent of the pore volume of the formation into which the steam is to be injected.

In another aspect, the present invention is useful in multibedded formations. Thus, in wells which penetrate hydrocarbon bearing formations in a number of distinct and separate zones, the invention may be utilized in each zone. For example, if a well penetrated a number of similar zones, the zones are processed separately. The first zone will be flooded with steam until breakthrough occurs. Based on the amount of steam needed for breakthrough in the first zone, subsequent zones will be processed by injecting between 40 and 60 percent of the steam required for breakthrough. For each succeeding zone, the amount of steam required is determined by weighing the amount of steam required for breakthrough in the first zone depending on factors such as thickness, permeability and water and oil saturation.

After a predetermined amount of steam as variously indicated above has been injected into the formation through the injection well steam injection is stopped. The formation is then pressure depleted by means of producing hydrocarbon fluids from the production wells. The producing wells are preferably kept pumped off to promote maximum recovery from the formation. Removal of fluids from the formation will cause the static pressure of the formation to decline. The static pressure of the swept portion of the formation should be reduced by production of fluids to a pressure less than the static pressure of the formation just before termination of steam injection to gain benefit from the present invention. It is desirable that the static pressure of the formation adjacent the injection well be reduced by production to at least 30 to 50 p.s.i. below the static pressure just before termination of steam injection depending, of course, on the particular formation and on the well spacing pattern. This reduction in pressure should be accomplished in from 6 months to a year in most instances and in less than two years in practically all cases. It is desirable, of course, that the static pressure in the field be reduced to as low a value as possible consistent with operating economics during this interval.

The static pressure of the formation may be determined by shutting in the production wells for a suitable time interval and determining the pressure at which the producing wells reach equilibrium. This technique is well known in the art and obviously should be done prior to steam injection as well as at intervals during the pressure depletion step. In this manner, the condition of the formation can be determined and proper timing of water injection can be insured.

When pressure depletion of the formation has progressed to a desirable state, water at ambient temperatures is injected through the injection well and into the formation. Water, for example, can be injected through line **25** at the wellhead. As the water contacts the residual heat bank in the formation caused by the passage of steam, it is vaporized because of the lower pressure existing in the reservoir. A secondary steam front is established and moved out into the formation by the water being injected into the formation. In this manner, much of the residual heat is utilized in recovering oil and an efficient and economical thermal process is continued in the formation.

Referring now to FIGURE 2, a series of curves are shown which illustrate the advantages of the present invention over other methods. The data illustrated in FIGURE 2 are from six steam floods conducted in a sand pack. Number 15 white oil was used to saturate a sand pack and distilled water was used for all floods. Number 15 white oil was chosen because it behaves similar to many heavy crude oils and is much easier to use in this type of experiment. Runs designated A and F represent the recovery extremes of low pressure steam displacement (A) and cold water flooding (F) in viscous oil systems.

Run A was a straight steam drive through a core with 0 p.s.i. back pressure. Steam temperature in run A ranged from 240°–310° F. Breakthrough recovery was 81 percent of the oil in place after 0.48 pore volumes of feed water converted to steam was injected. In this, and all other instances, injected pore volumes refer to the volume of feed water from which the steam is generated. That is, when indicating that 0.48 pore volume was injected it means that steam produced from feed water having a volume equal to 0.48 of the pore volume of the formation which is flooded was injected. Run F was a conventional cold water flood. In this flood, as expected, only 54 percent of the oil in place was recovered after 3.0 pore volumes of water was injected into the formation.

In Run C steam was also injected; however, in this run a 240 p.s.i.g. back pressure was maintained on the core. This run approximated the conditions of pressure and temperature which might occur in a field project. Nearly the same amount of oil was produced as in run A, but 0.86 pore volumes of feed water were required to reach breakthrough with a 410° F. steam. Increase in steam rquirements for this flood over the low pressure steam flood is to be expected from the formation heat balance. More heat is required to raise the formation to saturation temperature in higher pressure floods and the rate of thermal front advance is therefore lower.

Floods B, D and E were performed to evaluate operational methods in which a limited amount of steam is injected. In runs B and E cold water was injected after a pressure depletion step which reduced the sand pack pressure to atmospheric. In run D cold water was injected as soon as steam injection was completed without allowing pressure in the sand to decline.

Runs B, C, D and E were all conducted using steam at 410° F. The amount of steam injected into the core in run B was one-half the amount of steam required to produce breakthrough in run C. After steam injection was terminated in run B, 49 percent of the oil in place had been produced. The back pressure on the production end of the sand pack was then gradually reduced from 240 p.s.i.g. to atmospheric pressure. As a result of the boiling of the interstitial water in the steamed sand, the steam flood was advanced further through the sand pack and an additional 13 percent of the oil in place was produced. This is illustrated by the vertical portion of curve B. When the pressure was depleted, 62 percent of the oil in place had been produced and all of the interstitial water available in the sand had been vaporized. Cold water was then injected into the sand, which was still above saturation temperature, and it vaporized on contact with the hot sand thus producing additional steam and advanced the interstitial steam flood to the production end of the sand pack. The ultimate oil production in run B was approximately the same as in the straight steam floods A and C even though only one-half of the amount of steam was used.

Run D was identical to run B except that the pressured depletion step was omitted and water was injected at the saturation pressure of 240 p.s.i.g. In this case, the water caused the residual steam in the sand pack to condense and all fluid production stopped until liquid fill up was accomplished. Fill up required 0.28 pore volumes of water. After the core was full of liquid the run continued as an in situ hot water flood. The production response of run D was much less favorable than any of the steam floods, although it was better than the cold water flood (F) because of the improved mobility ratio.

Run E included a pressure depletion flood. Run E, however, differed from run D in that only ¼ of the amount of steam required for breakthrough was injected in run E. As shown by the short vertical portion of curve E, the pressure depletion step produced only 4 percent additional oil. This indicates that insufficient residual heat was available to develop and propagate a secondary steam front. However, it is interesting to note that the production responses of runs D and E are quite similar, even though run D consumed twice as much steam as run E. Run D also required a fill up period. Both runs D and E became hot water floods after steam injection was stopped. However, the advantages of run E over run D are apparent.

The comparison of runs B and C demonstrates that partial steam flooding followed by a pressure depletion step and then cold water injection can recover approximately as much oil as a conventional steam flood at substantially lower cost. Runs B and D demonstate the importance of a pressure depletion step. Runs B and E indicate that the amount of steam injected prior to the pressure depletion step is important in terms of overall recovery.

It is interesting to note, however, that recovery was improved for a given amount of steam injected in both runs B and E. In practice, the pressure depletion step prior to water injection is very important.

These demonstrations are graphically illustrated in curves A–F, and dramatically illustrate the value of the pressure depletion step in a steam plus water flood. Using the approach of the present invention, successful and economic steam assisted recovery is possible.

Although specific embodiments of the present invention have been described, the invention is not to be limited to only such embodiments but rather by the scope of the appended claims.

We claim:

1. A method of improving the recovery of oil from a hydrocarbon bearing formation comprising the steps of injecting stem through an injection well into a hydrocarbon bearing formation, continuing to inject steam through said injection well into said formation to develop a heat bank in said formation, stopping injection of steam into said formation, recovering oil from said formation through at least one production well to reduce the pressure in said formation to at least 30 pounds below the static pressure of the formation just before termination of steam injection, then injecting water through said injection well into said formation to establish a secondary steam bank in said formation and continuing to inject water into said formation to move said secondary steam

bank through said formation to assist in recovering additional oil therefrom.

2. A method of assisting the recovery of hydrocarbons from a hydrocarbon bearing formation penetrated by at least one injection well and one production well comprising generating steam from feed water and injecting said steam through said injection well into said reservoir, the amount of feed water used to generate said steam being between 15 and 20 percent of the sweepable pore volume of the formation, halting said steam injection and shutting in said injection well, producing fluids from said formation from said production well to lower the static pressure in said formation to at least 30 to 50 pounds below the static pressure of the formation just before termination of steam injection and then injecting water down said injection well into said formation while continuing to produce fluids from said production well.

3. A method of improving the recovery of oil from a hydrocarbon bearing formation comprising the steps of injecting steam through an injection well into a hydrocarbon bearing formation, the amount of steam injected being equal to an amount of between 40 to 60 percent the amount of steam required for breakthrough of steam into a production well, then halting steam injection and closing in said injection well, producing fluids from said production well to lower the static pressure in said formation at least about 30 to 50 p.s.i. less than the pressure in the swept portion of said formation during steam injection, opening said injection well and injecting water

through said injection well while continuing to produce fluids from said formation from said production well.

4. A method of improving the recovery of oil from a hydrocarbon bearing formation, said formation being penetrated by at least one injection well and one producing well comprising the steps of injecting steam into said formation through said injection well, continuing to inject steam through said injection well to develop a residual heat bank in said formation, then halting steam injection and shutting in said injection well, producing fluids from said producing well to lower the static pressure in said reservoir to a pressure at least 30 pounds less than the pressure existing in said reservoir during steam injection, then injecting water through said injection well and out into said formation and continuing to recover fluids from said production well.

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