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METHOD OF RECOVERING OIL FROM AN OIL-BEARING RESERVOIR

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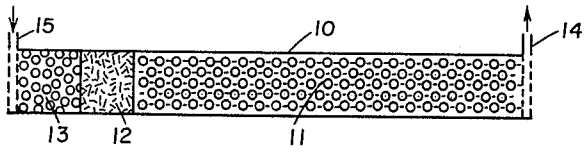


FIG. 1.

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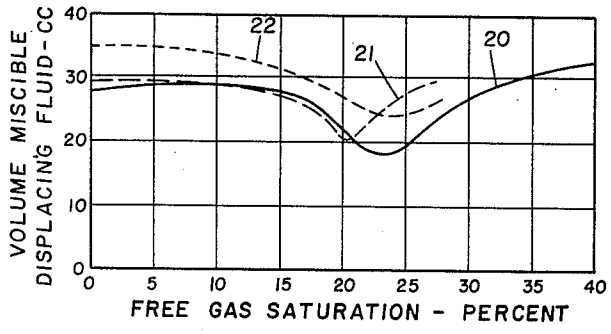


FIG. 2.

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METHOD OF RECOVERING OIL FROM AN OIL-BEARING RESERVOIR

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This invention relates to an improved method of recovering oil from an oil-bearing, subterranean earth formation. Specifically, this invention relates to a method of improving the efficiency of a primary oil recovery process by the employment of normally secondary recovery methods at a time during the primary recovery process when the free-gas saturation in the oil-bearing formation has increased into an optimum range.

Initial production of oil is normally achieved by permitting native reservoir energy to drive the oil from a formation to the surface through a well penetrating the formation. This method of oil production is commonly referred to as primary recovery. The native reservoir energy utilized in primary recovery may exist in the form of water, gas cap, or solution-gas drive, either singularly or in combinations thereof. These various forms of energy inherent in most newly penetrated oil-bearing formations provide the driving force for the removal of the oil without the necessity of providing energy from a source foreign to the formation. When the native reservoir energy of a formation is depleted or nearly depleted, it is common practice to apply secondary recovery methods which comprise the addition of energy from outside sources for the purpose of increasing the ultimate recovery of oil from the formation.

Many different forms of secondary recovery methods have been either actually employed or proposed. For example, probably the more common methods involve the introduction of water or gas through an injection well leading to the formation for the purpose of driving the remaining oil in the formation to a producing well. In some instances, water and gas have been used alternately. Among the numerous proposals, the following are typical examples of what has been suggested for introduction into a formation to improve the ultimate recovery of oil: liquefied petroleum gas and gas or enriched gas followed by either water alone or water and gas alternately; alternate slugs of liquefied petroleum gas and water; dry gas, followed by gas inriched with liquid propane and ethane, followed by ethane and propane, followed by water; liquefied petroleum gas, followed by gas; a liquefied petroleum gas slug alone; water, followed by a liquefied petroleum gas slug, followed by gas; and water, followed by a liquefied petroleum gas slug, followed by gas, followed by water.

It is to be noted that many of the above-suggested procedures of secondary recovery involve the use of liquefied, normally gaseous hydrocarbons such as liquefied petroleum gas. There is much disagreement as to the amount of liquefied petroleum gas which is needed to most efficiently produce oil remaining in a formation after the completion of primary recovery. Also, methods which employ liquefied petroleum gases are expensive operations. In view of the uncertainness of the amount of liquefied petroleum gas needed and its cost, the procedures using it have been rejected sometimes in favor of the commonly used water-flood operations which, while they may produce less oil, may be more economical.

We have found that during primary recovery such as a solution-gas drive, a well may be produced until an optimum range of conditions of free-gas saturation exists within the formation, at which time a minimum amount of hydrocarbon material which is miscible with the oil and gas in the formation may be introduced to obtain maximum oil recovery from the formation. Fundamentally, the present invention is neither a primary recovery process nor a secondary recovery process, but rather is a combination of the two processes, directed to the recovery of a maximum amount of oil from a formation with a minimum amount of miscible material being injected into the formation.

It is an object of this invention to provide a method of recovering oil from an oil-bearing reservoir. It is another object of this invention to provide a method of coordinating a primary recovery process with a miscible flood form of secondary recovery process in order to effect recovery of a maximum amount of oil from an oil-bearing reservoir. It is a further object of this invention to provide a method of combining a primary recovery process with a miscible flood process wherein a minimum amount of miscible hydrocarbon material is required to obtain a maximum amount of oil recovery from a formation. These and further objects and advantages of this invention will become apparent from a reading of the following description, taken in conjunction with the drawings.

In accordance with the invention, an oil-bearing reservoir is produced from at least one outlet well by primary recovery methods until the free-gas saturation in the reservoir has increased to within a predetermined range, preferably about 15 percent to about 30 percent of the hydrocarbon pore volume of the reservoir. When the stated degree of free-gas saturation has been obtained, a quantity of hydrocarbon material which is miscible with the oil and the gas in the reservoir is introduced into the reservoir through at least one input well. This miscible material is followed by the introduction of a driving fluid into the formation through the input well. The oil and the miscible hydrocarbon material are driven through the formation toward the outlet well by the driving fluid until oil and gas are produced from the outlet well.

A producing reservoir, that is, one which is capable of being produced by solution-gas drive, normally in its virgin state contains fluid in essentially one liquid oil phase. This liquid oil phase consists of various molecular weight hydrocarbons, each of which under normal atmospheric conditions is either in the gaseous or liquid state. The reservoir, therefore, consists of normally gaseous hydrocarbons which are dissolved in normally liquid hydrocarbons. The liquid found in such a reservoir possesses a property known as its original saturation pressure. The original saturation pressure is the pressure above which all of the hydrocarbons will remain in the liquid phase, that is, above this pressure the normally gaseous hydrocarbons remain dissolved in the normally liquid hydrocarbons. Originally, the reservoir pressure may be far in excess of the saturation pressure of the liquid found in the reservoir. When, under such conditions, the reservoir liquid is permitted to flow from the reservoir through an outlet well, the liquid tends to expand with decrease in pressure, driving some of the reservoir oil out through the outlet well. Such a form of production is known as liquid expansion. After such reservoirs have been produced by liquid expansion for some period of time, the reservoir pressure will eventually decrease to the point where it will equal the saturation pressure of the liquid in the reservoir. At the time when the reservoir pressure is equal to the saturation pressure of the liquid in the reservoir, the liquid is said to be saturated, and therefore any further reduction in the reservoir pressure will result in the existence of free gas within the reservoir. As gas escapes from solution and becomes free gas, it occupies a larger volume than when it was dissolved in the oil. The increased volume, occupied by gas escaping from solution, drives both oil and gas from

the reservoir through the outlet well. Such a form of production is known as solution-gas drive. As the reservoir is permitted to further produce by solution-gas drive, this free gas will increase in amount.

For purposes of definition, the term "hydrocarbon pore volume" as used herein means that volume of the pore space in a reservoir which was originally occupied by hydrocarbons, whether in the gaseous or liquid, or both phases. It is to be understood that such definition does not contemplate the existence of a "gas cap," and should such exist within a reservoir its volume would not be taken into consideration in the determination of the hydrocarbon pore volume of the reservoir.

The term "free-gas saturation" as used herein refers to the percentage of the hydrocarbon pore volume occupied by a gas in the free state. For example, if a reservoir is produced by solution-gas drive until the free-gas saturation is 15 percent, that portion of the reservoir which originally was filled with hydrocarbons in the liquid state is now occupied by hydrocarbons in the liquid state and hydrocarbons in the free-gaseous state, with the hydrocarbons in the free-gaseous state comprising 15 percent and the hydrocarbons in the liquid state comprising the remaining 85 percent.

A normal hydrocarbon-bearing reservoir is usually occupied also by water. The presence or absence of water, however, does not affect the processes of the present invention since by definition the hydrocarbon pore volume is that portion of the reservoir originally occupied by hydrocarbon, not water, and the percentage of free-gas saturation is that portion of the hydrocarbon pore volume of the reservoir occupied by gas in the free state at a particular stage in the production of oil from the reservoir.

Referring to the drawings, FIGURE 1 is a diagrammatic representation of an oil-bearing reservoir penetrated by at least one inlet well and one outlet well. FIGURE 2 shows a series of curves illustrating the range of free-gas saturation in which a minimum volume of miscible material may be employed in accordance with the invention.

Referring to FIGURE 1 of the drawings, the reference numeral **10** denotes the hydrocarbon-bearing portion of a producing reservoir at a stage in the process of the invention when a slug of miscible material and a driving gas have been established in the reservoir. Portion **11** of the reservoir is that portion of the reservoir which contains what remains of the original liquid and gaseous hydrocarbons. For example, portion **11** may have a free-gas saturation of 20 percent, which means that 20 percent of the pore space occupied by hydrocarbons in the formation of portion **11** is occupied by gas in a free state, while 80 percent of portion **11** is occupied by hydrocarbons in a liquid state. The liquid hydrocarbons in portion **11** will contain some gas in the dissolved state. It will be understood by those skilled in the art that there is no clear line of demarcation in portion **11** between the zones containing the gas in the free state and liquid hydrocarbons. The free gas and the liquid hydrocarbons within portion **11** will be intermixed. Portion **12** of reservoir **10**, as shown, is occupied by a slug of miscible material which, as hereinafter explained, may be either in the liquid or gaseous state. Though the line of division between portion **11** and portion **12** is clearly fixed geometrically in FIGURE 1, it will be readily understood that in actual practice this is not a clear line of division inasmuch as there will be some fingering of the slug of miscible material into the hydrocarbons of portion **11** and there will be a zone of transition between the material in portion **11** and that in portion **12** wherein the slug of miscible material is intermixing with the hydrocarbons in portion **11**. Portion **13** of reservoir **10** is shown as being filled with driving fluid. Wells **14** and **15**, as shown, penetrate reservoir **10**. In the initial phase of the process of the invention, wells **14** and **15** may both function as producing wells. On the other hand, only one of these wells may, if desired, be used as a producing well. In the later stages of the process of this invention, one of wells **14** and **15** will be established as an outlet well, while the other well is established as an inlet or injection well.

The first, or initial, phase of the process of our invention comprises the production of an oil-bearing reservoir through at least one well by primary production methods. The pressure within reservoir **10** is above 1000 p.s.i. and may be above 2000 p.s.i. or even higher. The temperature within the formation may range from about 75° F. to about 250° F. or even higher. Initial production from reservoir **10** may be accomplished through either, or both, wells **14** and **15** by free flow such as liquid expansion and solution-gas drive, if the pressure within the reservoir is sufficient to effect the desired flow from the reservoir through these wells. If the pressure of the reservoir is not sufficient for such means of production, production may be effected by pumping, by gas lift, or by other assist methods. This first step in our process is continued until reservoir pressure is decreased to the extent that the free-gas saturation of the reservoir has increased to a value in the range of about 15 perecnt to about 30 percent by volume of the hydrocarbon pore space in the reservoir. The percentage of free-gas saturation may be readily determined by means well known to those skilled in the art, such as by material balance calculations and laboratory studies of the formation oil and gas phase-behavior. When the desired percentge range of free-gas saturation within the reservoir has been established by primary production methods, the second step, or phase, of our process may be initiated.

In the second step of the process of our invention, at least one well penetrating the oil-bearing reservoir acts as a producing or outlet well, while at least one other well penetrating the reservoir acts as an inlet or injection well. In the example illustrated in FIGURE 1 of the drawings, well **14** functions as a producing well while well **15** serves as an injection well. The second step of our process comprises establishing a zone of miscible fluid in the reservoir between the production well and the injection well. In FIGURE 1, this miscible fluid is represented as occupying portion **12** of the reservoir behind portion **11**, which is ociupied by the hydrocarbons to be produced by the process of our invention. This miscible fluid is often referred to by those skilled in the art as a miscible slug. The miscible slug shown in portion **12** comprises, in the preferred embodiment of the invention, hydrocarbon material which exists in the liquid state or as a single phase fluid at the reservoir pressure, though it is to be understood that this miscible slug may also be what is referred to as an enriched gas. The miscible slug in portion **12** of the reservoir is established by introduction of the hydrocarbon material into the reservoir through injection well **15**.

The material comprising the miscible slug may be a hydrocarbon fluid which is miscible with the oil and gas in the formation, such as an enriched gas, or liquefied, normally gaseous hydrocarbons, such as liquefied petroleum gas. The introduction of the miscible slug is made at pressures sufficient to establish and maintain it as a single-phase fluid slug which is miscible with the oil and gas in the reservoir. The material comprising the slug to be established in the reservoir may also exist as a liquid hydrocarbon containing from two to five carbon atoms per molecule and not more than trace amounts of higher molecular weight hydrocarbons. The injection pressures of this latter material must, of course, be such that the material will be maintained as a liquid in the reservoir. Also, it is to be understood that this miscible slug may comprise ethane, propane, butane, or pentane, or mixtures of these, or liquefied petroleum gas consisting of a mixture of relatively minor amounts of ethane, larger amounts of propane and butane, with a minor amount of pentane, and not more than trace

amounts of hexane and higher molecular weight hydrocarbons with the total amount of hexane and higher molecular weight hydrocarbons comprising generally less than about two mol percent of the liquefied petroleum gas mixture forming the slug. It is to be further understood that the miscible slug may also comprise an enriched gas formed of methane of not more than 40 mol percent, ethane of not more than 30 mol percent, with the remainder of the blend being comprised of higher molecular weight saturated hydrocarbons of not more than five carbon atoms with trace amounts of hexane and higher molecular weight saturated hydrocarbons. The miscible slug may also comprise a miscible gas formed of ethane, propane, and butanes existing as a single-phase gas in a reservoir which obtains a temperature higher than the critical temperature of the mixture, or any of the above pure hydrocarbons which would be directly miscible may be employed.

The amount of hydrocarbon material making up the miscible slug preferably is in the range of about 1 to 10 percent of the hydrocarbon pore volume of the reservoir to be swept by the slug. Several conditions of the reservoir are factors which operate to control the amount of hydrocarbon material making up the slug. Some of these conditions which have been recognized as factors controlling the amount of material required for the slug are as follows: relative permeabilities and porosities of different zones of the reservoir; the area to be swept by the hydrocarbon material of which the slug is formed; the composition and physical properties of the slug material; the interstitial water present in the reservoir; the temperature and the pressure of the reservoir at the time of injection of the slug; the properties of the oil in the reservoir to be driven out by the slug, such as the viscosity of the oil; the volume of the reservoir to be swept by the slug; and the distance between the input and outlet wells. The effect of some of these factors can be determined by core analysis of the reservoir and by other methods well known to those skilled in the art.

The above-mentioned factors, together with the free-gas saturation in the reservoir, affect the length of the transistion zone between the miscible slug and the oil in the reservoir which is to be swept from the reservoir by the miscible slug. Referring to FIGURE 1, this transition zone, which contains a mixture of miscible material and reservoir oil and gas, is located in that portion of the reservoir in the area of the boundary between portion **11** and portion **12**. It is in this transition zone that the mixing occurs between the slug material and the reservoir oil. This transition zone varies with respect to the concentration of slug material and reservoir oil. At the front of the slug, that is, that part in the slug adjacent to portion **11**, there is a high reservoir oil-low slug material content, while this ratio changes moving toward the slug material zone where it will be found there is a low reservoir oil-high slug material content. It is the length of this transition zone which is a major factor controlling the amount of miscible slug material required to effect the desired removal of the reservoir oil.

Most of the above-discussed factors which affect the amount of the material making up the miscible slug are conditions which are inherent to the reservoir and are, therefore, not controllable. The matter of the free-gas saturation of the hydrocarbon pore volume of the reservoir is, however, controllable, and in accordance with the invention, we have found that the free-gas saturation has a major effect upon the amount of slug material required. FIGURE 2 illustrates the relationship between the percentage of free-gas saturation of the hydrocarbon pore volume of the reservoir and the quantity of material making up the miscible slug for several systems tested. The effect of the percentage of free-gas saturation of the hydrocarbon pore volume of the reservoir upon the required quantity of material in the miscible slug was investigated with two diffeernt gas-oil systems, namely, a 38° API gravity crude oil-natural gas system and a Sovasol-methane system. Referring to FIGURE 2, curve **20** represents the results of a test on a crude oil-natural gas system; curve **21** represents a test made on a Sovasol-methane system; and curve **22** represents a test made on a Sovasol-methane system at a reservoir pressure different from that at which the data for curve **21** was obtained. Each of the curves in FIGURE 2 illustrates the minimum quantity of displacing fluid required to effect oil production by slug action or, in other words, without breakthrough of driving fluid prior to complete displacement of the oil. Stated otherwise, the curves in FIGURE 2 illustrate the minimum quantity of displacement fluid needed to maintain discrete slugs during production of substantially all the oil from the tubes employed in the test runs.

The tests which provided the data shown in FIGURE 2 were carried out in a sand-packed tube which was 50 feet long and had an inside diameter of 0.305 inch. The sand employed in packing the tube had a particle size capable of passing through a 60-mesh screen. To obtain the data represented in curve **20**, 38° API gravity crude oil containing dissolved natural gas was introduced into a sand-packed tube as above described. The viscosity of the crude oil containing the dissolved natural gas was 1.5 centipoises at 130° F. For the purpose of developing curve **20**, a series of test runs were made in the tube with the free-gas saturation of the hydrocarbon system within the sand pack being at 2.0 percent, 16.3 percent, 22.8 percent, 32.6 percent, 37.1 percent, and 39.4 percent, respectively. All of these test runs were made with the pressure within the tube being at approximately 1200 p.s.i., there existing a slight pressure differential between the ends of the tube to effect the desired fluid flow through the tube. In order to carry out each of the runs, the sand pack was pressured to a high enough level to both establish an initial condition of zero percent free-gas saturation within the hydrocarbon system in the sand pack and provide the desired percent of free-gas saturation for the particular run when the pressure was reduced to 1200 p.s.i. In other words, the initial pressure for each run was sufficiently high that when the pressure was reduced to 1200 p.s.i. the desired free-gas saturation existed within the sand pack. For example, in making the first run the sand pack was initially pressured to a level which established zero percent free-gas saturation. This initial pressure level for this run was also sufficiently high that when the pressure was reduced within the tube to 1200 p.s.i. the free-gas saturation was 2.0 percent. Obviously, for the succeeding runs at the other free-gas saturations above enumerated, it was necessary that the initial pressure within the sand pack be somewhat greater than that for the 2 percent free-gas saturation run in order that when the pressure was reduced to 1200 p.s.i. the free-gas saturation would be at the desired level. With respect to each of these test runs, when the free-gas saturation was established at the desired level at 1200 p.s.i., propane was introduced into one end of the tube to serve as the miscible slug for displacing the reservoir oil from the sand pack. The propane was driven through the tube to produce the oil from the sand pack. The content of the propane-oil transition zone was measured by compositional analysis of the effluent. For each of the runs, a determination was made of the minimum quantity of propane required to produce the oil from the tube by slug action without breakthrough of the driving fluid prior to substantially complete displacement of the oil from the sand pack.

Similar tests as described above were carried out in a sand-packed tube for the Sovasol-methane systems as represented by curves **21** and **22** in FIGURE 2. Sovasol is a close-boiling naphtha of 300°–400° F. boiling range. The test was carried out at 1800 p.s.i. pressure with the

sand pack being at 75° F. The viscosity of the Sovasol-methane system at this temperature and pressure was 0.522 centipoise. The data on which curve **21** is based was obtained by determining the propane content of the transition zone between the oil and the propane for zero percent, 19.4 percent, and 26.9 percent free-gas saturation. Curve **22** was obtained by testing a Sovasol-methane system using the above-described procedure at 1500 p.s.i. with the sand pack being at 75° F. During this latter test the system was depressured by solution-gas drive to a free-gas saturation of 27.8 percent.

It is evident from an examination of FIGURE 2 that the optimum range requiring a minimum amount of miscible slug extends from approximately 15 percent to about 30 percent free-gas saturation of the hydrocarbon pore volume. The advantage of operating in this optimum range is evidenced by the fact that at lower and higher free-gas saturations, that is, below about 15 percent and above about 30 percent, the quantity of miscible slug required is increased at least 40 percent above the minimum requirement within the desired range in accordance with our invention.

The third step in the process of our invention comprises the estbalishment of a driving fluid within reservoir **10** behind the miscible slug described in step 2 above. Referring to FIGURE 1, this driving fluid is represented as filling portion **13** of reservoir **10**. The driving fluid is introduced into the reservoir through injection well **15**. The driving fluid introduced in step 3 preferably is a fluid which is miscible with the hydrocarbon material forming the miscible slug described in step 2. The driving material of this step may be a flue gas, air, nitrogen, carbon dioxide, or a relatively lean natural gas such as separator gas. The driving fluid of this step is introduecd into the reservoir through well **15** at a pressure sufficient to establish miscibility with the hydrocarbon material of the miscible slug in order that the slug will be driven through the reservoir toward well **14**. Injection of the driving fluid is continued at least until delivery of the miscible slug of step 2 is effected at the outlet well **14**, or until the effluent from well **14** consists substantially of the driving fluid. As the miscible slug is driven through the formation, it picks up reservoir oil and gas and forces them from the reservoir through the outlet well.

Thus, it is seen that in accordance with out invention an oil-bearing reservoir is produced by solution-gas drive or other primary methods of oil production until the hydrocarbon pore volume of the reservoir contains a free-gas saturation within the range of approxmiately 15 percent to about 30 percent, a slug of hydrocarbon material miscible with the reservoir oil and gas is established in the reservoir, and a driving fluid is injected into the reservoir behind the miscible slug thus driving the miscible slug through the reservoir until the reservoir oil and gas are driven from the reservoir through an outlet well.

What is claimed is:

1. In a method of recovering oil from a subterranean reservoir provided with at least one injection well and at least one production well the steps which comprise:

producing oil from said reservoir by primary production until the free-gas saturation within said reservoir is within the range of about 15 percent to about 30 percent of the hydrocarbon pore volume of said reservoir;

introducing into said reservoir through said injection well a quantity of fluid hydrocarbon material miscible with the oil remaining in said reservoir, said hydrocarbon material being injected at a pressure sufficient to establish miscibility with said oil;

introducing into said reservoir through said injection well a driving fluid, said driving fluid being miscible with said hydrocarbon material and being introduced at a pressure sufficient to establish miscibility with said hydrocarbon material;

forcing said oil and said hydrocarbon material through said reservoir toward said production well by means of said driving fluid; and

producing oil from said reservoir through said production well.

2. In a method of recovering oil from a subterranean reservoir provided with at least one injection well and at least one production well the steps which comprise:

producing oil from said reservoir by primary production until the free-gas saturation of said reservoir is within the range of about 15 percent to about 30 percent of the hydrocarbon pore volume of said reservoir;

introducing into said reservoir through said injection well a hydrocarbon fluid miscible with the reservoir oil at the temperature and pressure existing within said reservoir, the quantity of said fluid ranging from about 1 percent to about 10 percent of the hydrocarbon pore volume of said reservoir.

introducing into said reservoir through said injection well a driving fluid miscible with said hydrocarbon fluid, said driving fluid being introduced at a pressure sufficient to establish miscibility with said hydrocarbon fluid;

forcing said hydrocarbon fluid and said reservoir oil through said reservoir toward said production well by means of said driving fluid; and

producing said reservoir oil from said reservoir through said production well.

3. The method of claim 2 wherein the said hydrocarbon fluid is an enriched hydrocarbon gas.

4. The method of claim 2 wherein the said hydrocarbon fluid is a liquefied, normally gaseous hydrocarbon material, said fluid being introduced at a pressure sufficient to maintain said fluid as a liquid slug within said reservoir.

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