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[54] **METHOD TO MEASURE FLUID DRIFT AND IMMOBILE PHASE SATURATION**

[75] Inventors: **John F. Tomich; Harry A. Deans,** both of Houston, Tex.

[73] Assignee: **Exxon Production Research Company,** Houston, Tex.

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[52] **U.S. Cl.** **73/155;** 73/155
[51] **Int. Cl.**[2] **E21B 47/10**
[58] **Field of Search** .... 73/61.1 C, 155, 432 R

[56] **References Cited**

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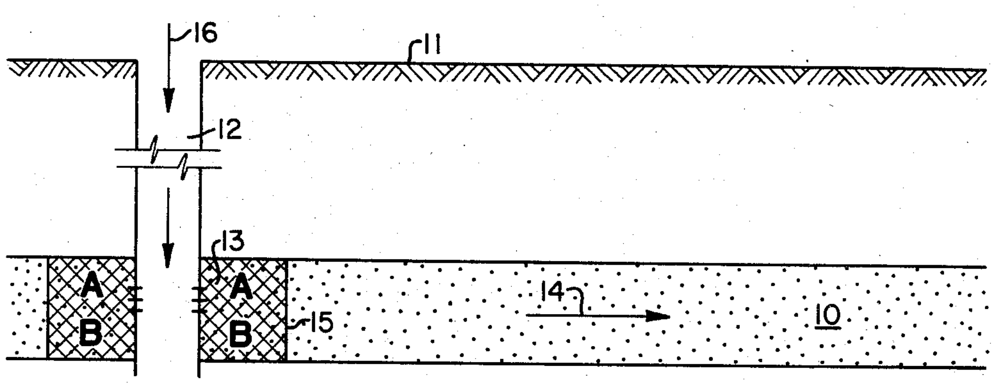
Primary Examiner—Donald O. Woodiel
Attorney, Agent, or Firm—Lewis H. Eatherton

[57] **ABSTRACT**

Disclosed herein is a method for determining the relative amounts of fluid phases in a subterranean oil-bearing formation in which one of the phases is mobile and the other is essentially immobile and in which the mobile fluid phase has a substantial degree of fluid drift within the subterranean formation. A carrier fluid containing two tracers having significantly different partition coefficients between the carrier fluid and the immobile phase is injected into the formation by means of a well. The well is then shut-in, and the carrier fluid with the two tracers is permitted to move within the formation solely under the influence of the fluid drift. Due to the difference in distribution coefficients of the two tracers, there will be a chromatographic separation of the tracers due to the movement in the formation under the influence of fluid drift during injection, shut-in and production. The well remains shut-in for a period which is sufficient to give a distinct and measurable separation of the two tracers due to the influence of fluid drift. Subsequently, the well is placed on production, and the concentration of the tracers in the produced fluids is measured as a function of time, volume or other chromatographic property. By applying the principles of chromatography to measured chromatographic properties of the process, the fluid saturations of the formation and the magnitude of fluid drift in the formation can be determined.

9 Claims, 4 Drawing Figures



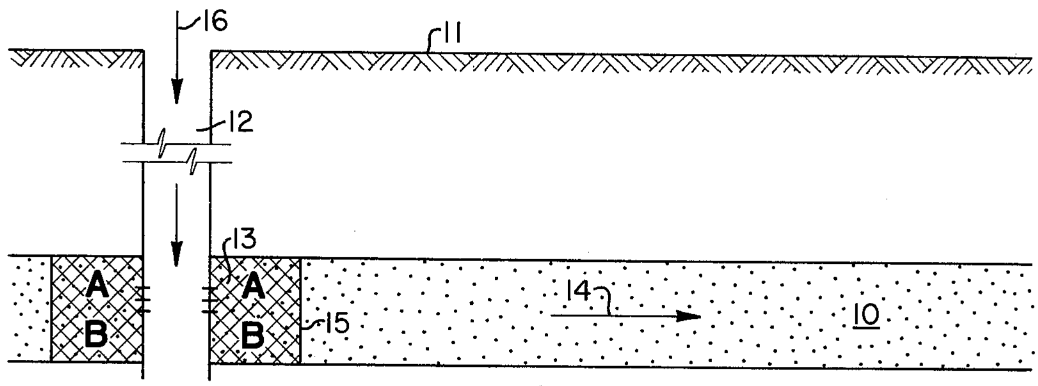


FIG. 1

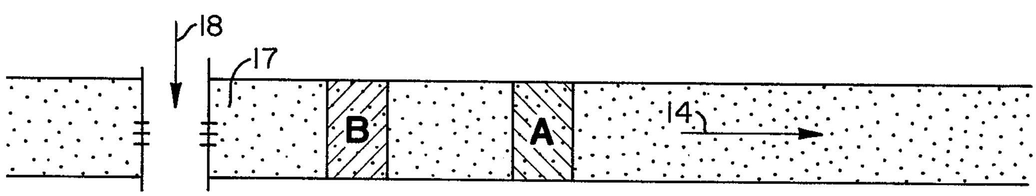


FIG. 2

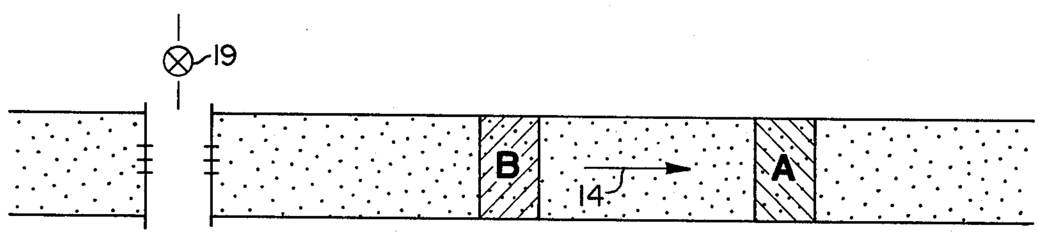


FIG. 3

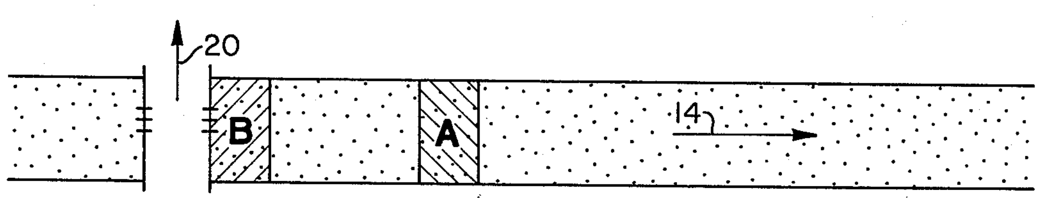


FIG. 4

METHOD TO MEASURE FLUID DRIFT AND IMMOBILE PHASE SATURATION

BACKGROUND OF THE INVENTION

1. Field of the Invention

This invention relates to a process utilizing a well or wells, and includes the steps of testing or measuring formation fluids. More specifically, this invention relates to a method for determining fluid saturations in a subterranean reservoir penetrated by a well where the mobile fluid in the reservoir has a substantial fluid drift.

2. Description of the Prior Art

A typical oil-productive formation is a stratum of rock containing tiny, interconnected pore spaces which are saturated with oil, water, and gas. Knowledge of the relative amounts of these fluids in the formation is indispensable to proper and efficient production of the formation oil. For example, when a formation is first drilled it is necessary to know the original oil saturation to intelligently plan the future exploitation of the field. In tertiary recovery techniques, such as solvent flooding, the quantity of oil present in the formation will often dictate the most efficient manner of conducting such an operation. The concentration of oil in the formation may indicate which of several alternative, tertiary recovery techniques might best be employed to produce the oil.

There are several methods which are currrently used to determine the fluid saturations of a formation. Coring is the most commonly used technique for acquiring this information. This is a direct sampling of the formation rock and liquids. For example, a small segment of the formation rock, saturated with its fluids, is cored from the formation and removed to the surface where its fluid content can be analyzed. This method, however, is susceptible to faults of the sampling technique; thus, the sample taken may, or may not, be representative of the formation as a whole. Also, there is a genuine possibility that the coring process itself may change the fluid saturation of the extracted core. Moreover, coring can only be employed in newly drilled wells or open hole completions. In the vast majority of wells, casing is set through the oil-bearing formation when the well is initially completed. Subsequently, therefore, core samples cannot be obtained from such a well. Finally, coring by its very nature only investigates the properties of the formation rock and fluids in the immediate vicinity of the wellbore.

Another approach for obtaining reservoir fluid saturations is by logging techniques. These techniques also investigate the formation rock and fluid properties for only a very short distance beyond the wellbore. These techniques study the rock-fluid system as an entity; it is often difficult by this approach to differentiate between the properties of the rock and its fluids.

Material balance calculations based on production history are another approach to the problem. Estimates of fluid saturation acquired by this method are subject to even more variables than coring or logging. This technique requires a knowledge of the initial fluid saturation of the formation by some other method and knowledge of the source of the recovered fluids.

More recent methods for determining fluid saturations in a subterranean formation are concerned with trace chemicals injected into and produced from the formation. In one such method a carrier fluid containing at least two tracers having differing partition coefficients between the immobile fluid phase of the formation and the carrier fluid in which the tracers are contained are injected into one location in the formation and produced from another. Due to the differing partition coefficients of the tracers, they will be chromatographically separated as they pass through the formation, and this chromatographic separation is a function of the saturation of the immobile phase.

In another tracer method, a carrier fluid containing a reactive chemical substance is injected into the formation through a well. The carrier fluid-reactant solution is displaced into the formation, and the well is shut-in to permit the reactant to be converted in part to produce additional tracer material having a partition coefficient which is different from that of the reactant. When the well is produced, the unconsumed reactant and resultant product are chromatographically separated, and the degree of separation is a function of the saturation of the immobile fluid phase as a result of their differing partition coefficients.

While both of these methods have applicability in determining fluid saturation in a subterranean formation, they are subject to certain drawbacks. In the first method, the carrier fluid-tracer solution must be injected into one location in the formation and produced from another. (In most practical applications, this means that two wells — one for injection and one for production — are required for the practice of the invention.) The second method requires only one well for injection and production. However, the use of a chemical which reacts within the formation complicates analysis of the results.

SUMMARY OF THE INVENTION

In accordance with the teachings of this invention, the fluid saturations of a hydrocarbon-bearing formation containing a mobile fluid and an immobile fluid where the mobile fluid is subject to significant fluid drift are determined by injecting a carrier fluid containing two tracers having differing partition coefficients. In the preferred embodiment, the carrier fluid-tracer solution is displaced into the formation by a tracer-free fluid and the well is shut-in. During the shut-in period, the two tracers move through the formation and separate by a distinct and measurable amount due to fluid drift. Subsequently, the well is placed on production and the produced volumes are measured and analyzed for the presence and concentration of the two tracers. Since the tracers have differing partition coefficients between the carrier fluid and the immobile phase, they are chromatographically separated by the influence of fluid drift which occurs during the injection, shut-in, and production phases. By correlating the produced volumes and the concentrations of the two tracers, the relative proportions of mobile and immobile phases can be determined.

Objects and features of the invention not apparent from the above discussion will become evident upon consideration of the following description of the invention taken in connection with the accompanying drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a schematic representation or cross section of the earth showing a subterranean formation penetrated by a well and showing the location of the carrier fluid-tracer solution after it has been injected into the formation.

FIG. 2 is a schematic representation of the formation and shows the displacement of the carrier fluid-tracer solution through the formation.

FIG. 3 is a schematic representation of the formation and shows the relative positions of the tracers as they move through the formation under the influence of fluid drift.

FIG. 4 is a schematic representation of the formation and shows the arrival of one of the tracers at the well.

DESCRIPTION OF THE INVENTION

It will be apparent from this disclosure that the method of this invention has broad applicability. For purposes of clarity, only one of the many uses of this invention — determination of the residual oil saturation in a watered-out reservoir using a single well — will be described in detail. The use of this method for other purposes will be readily apparent from this description.

FIG. 1 shows a subterranean oil-bearing formation **10** lying below the surface of the earth **11**. The formation is penetrated by a well **12** which has been drilled from the surface and perforated at **13** to provide fluid communication between the interior of the well and the formation.

The portion of the formation being tested is watered-out. When well **12** was initially completed, the formation in the immediate vicinity of the well was oil-productive. However, as oil was produced from well **12** and other wells higher in the formation, a strong, natural, waterdrive displaced oil from the lower portions of the reservoir. At this point in time no measurable quantities of oil are being produced from well **12**. The reservoir pressure is above the bubble point of the oil, and no free gas exists in the reservoir. The thickness-porosity factor (Hϕ) for the formation **10** is approximately 12.7.

The reservoir in the vicinity of well **12** is subject to "fluid drift". It should be understood that the term "fluid drift" as used herein refers to the movement of fluid within the formation due to causes other than injection or withdrawal of fluids at the well. In this instance, the fluid drift, whose direction is shown by arrow **14**, is a result of withdrawal of oil at an updip location in the reservoir and the influx of water downdip of well **12**.

A solution of tracers A and B in a suitable carrier fluid is prepared at the surface. In this example, tracer A is ethanol, tracer B is methyl propyl ketone; and brine previously produced from the formation is used as the carrier fluid. Five hundred barrels of the carrier fluid-tracer solution **15** are injected into the formation at a rate of 850 barrels per day, as indicated by arrow **16**.

As is shown in FIG. 2 the carrier fluid-tracer solution is displaced into the formation by injecting an additional 1000 barrels of the brine **17** as is indicated by the arrow **18**. The injection continues until a total volume of 1500 barrels has been displaced into the formation with a total injection period of approximately 42 hours.

After the carrier fluid-tracer solution has been displaced into the formation by the brine **17** to a desired distance, the surface controls (shown diagrammatically at **19**) are closed, and the well is shut-in for approximately 10 days. During the shut-in period, tracers A and B move through the formation under the influence of fluid drift as indicated by arrow **14**. After tracers A and B have moved through the formation for a sufficient distance to permit the tracers to separate by an amount which will be interpretable as separation due to fluid drift, the well is placed on production and fluids are withdrawn to the surface. In this instance the shut-in period is approximately 10 days.

As is shown in FIG. **4**, tracers A and B return to the well during this production phase and the concentration of the alcohol and of the ketone are measured as a function of produced volumes. Such concentration-produced volume curves are then matched against curves which are simulated in the manner hereinafter discussed assuming various fluid drift velocities and various fluid saturations. The simulated curve which best fits the actual data gives the value for fluid drift and for fluid saturation. For example, in the case given above the best match between calculated and actual data was derived from a curve which was simulated using a 0.65 foot/day fluid drift and a 14% residual oil saturation.

At times the field data cannot be so precisely matched to the simulated curves. This can result from minor errors in measuring the data in the field or from physical phenomena occurring within the fluid system or the reservoir which is not precisely accounted for in the calculational procedure. However, even in such instances the actual data can be bracketed, with a high degree of precision, with simulated curves to give fluid saturations within the resevoir which are accurate within a small percentage deviation.

It should be noted that this invention avoids the "mirror image" effect which will make residual oil saturation impossible to determine. This mirror image effect will occur where two or more nonreactive tracers having different partition coefficients are injected into a formation where the mobile fluid is not under the influence of fluid drift and these tracers are withdrawn from the formation by means of the same well. The tracers will separate as they are injected into the formation, and the degree of separation will be a function of the residual oil saturation. However, when the tracers are withdrawn from the formation by means of the same well, this separation will disappear. When the tracers moved away from the well, one tracer moved faster and a further distance through the formation than the other due to the difference in partition coefficients and due to the residual oil in the formation. When the well was placed on production, the tracer which was further from the well again moved faster than the other, and the two tracers arrived at the well at approximately the same time. Thus, the separation which is indicative of residual oil saturation was wiped out.

The mirror image effect does not occur in the practice of this invention. The fluid drift in the mobile fluid phase introduces a factor which destroys the reversibility of the separation-coalesence of the tracer. Thus the separation of the tracers in the practice of this invention is indicative of fluid saturations within the formation.