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(54) DETERMINATION OF AN ACTUAL OPTIMUM SALINITY AND AN ACTUAL OPTIMUM TYPE OF MICROEMULSION FOR SURFACTANT/POLYMER FLOODING

(75) Inventor: **James J. Sheng**, Katy, TX (US)

Correspondence Address:
FULBRIGHT & JAWORSKI L.L.P
2200 ROSS AVENUE, SUITE 2800
DALLAS, TX 75201-2784 (US)

(73) Assignee: **Total E&P USA, Inc.**, Houston, TX (US)

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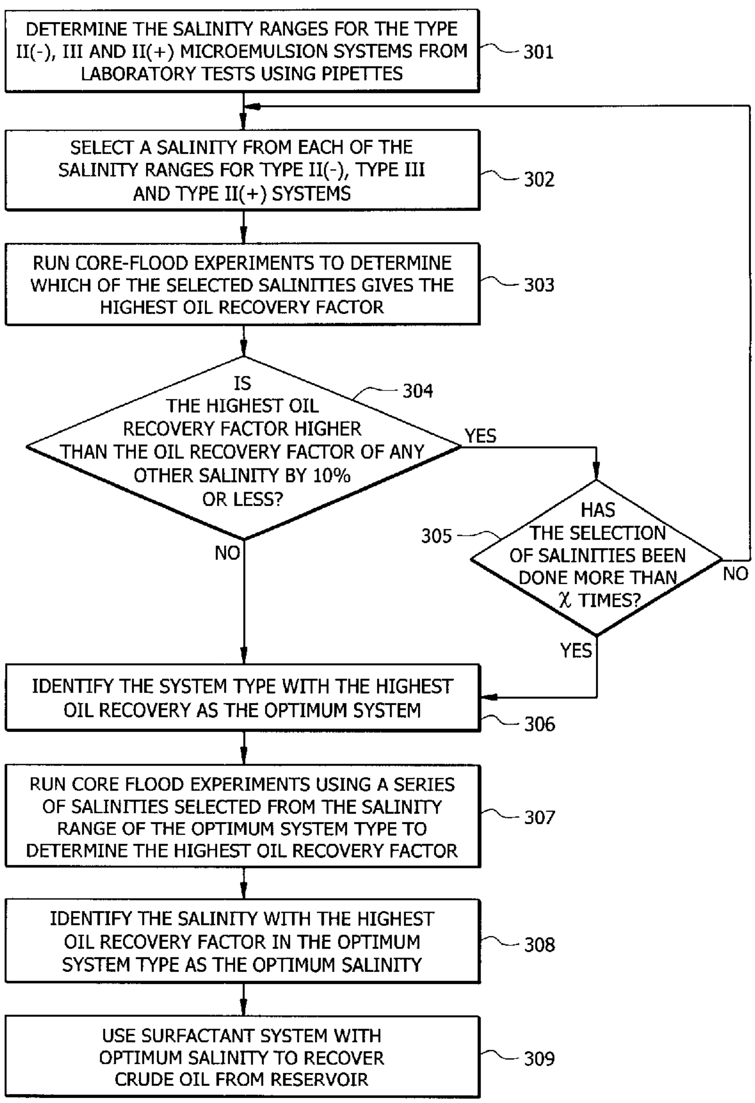
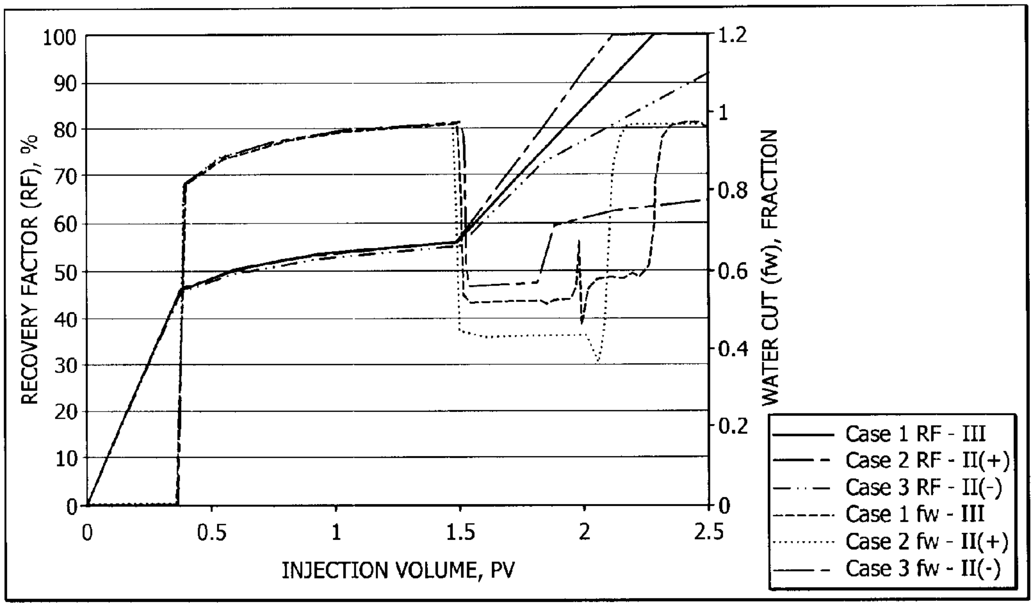
(57) **ABSTRACT**

Systems and methods for the determination of an optimum salinity type and an optimum salinity of a surfactant micro-emulsion system are shown. Optimum salinity type and optimum salinity in surfactant/polymer flooding is determined, according to embodiments, by core-flood experiments so that a variety of multiphase flow parameters such as relative permeability and phase trapping that affects oil recovery factor, influences the determination of the optimum salinity type and optimum salinity. The optimum salinity determined from this approach preferably corresponds to the highest oil recovery factor.

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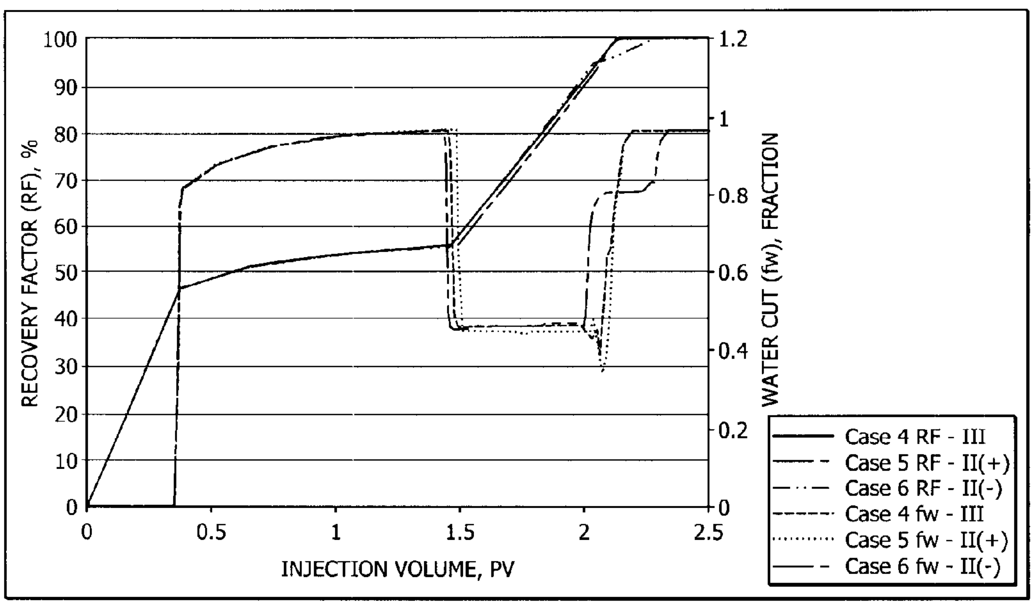
RECOVERY FACTOR (RF), %
WATER CUT (fw), FRACTION
INJECTION VOLUME, PV
Case 1 RF - III
Case 2 RF - II(+)
Case 3 RF - II(-)
Case 1 fw - III
Case 2 fw - II(+)
Case 3 fw - II(-)

FIG. 1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1.5
2
2.5
RECOVERY FACTOR (RF), %
WATER CUT (fw), FRACTION
INJECTION VOLUME, PV
Case 4 RF - III
Case 5 RF - II(+)
Case 6 RF - II(-)
Case 4 fw - III
Case 5 fw - II(+)
Case 6 fw - II(-)

FIG. 2

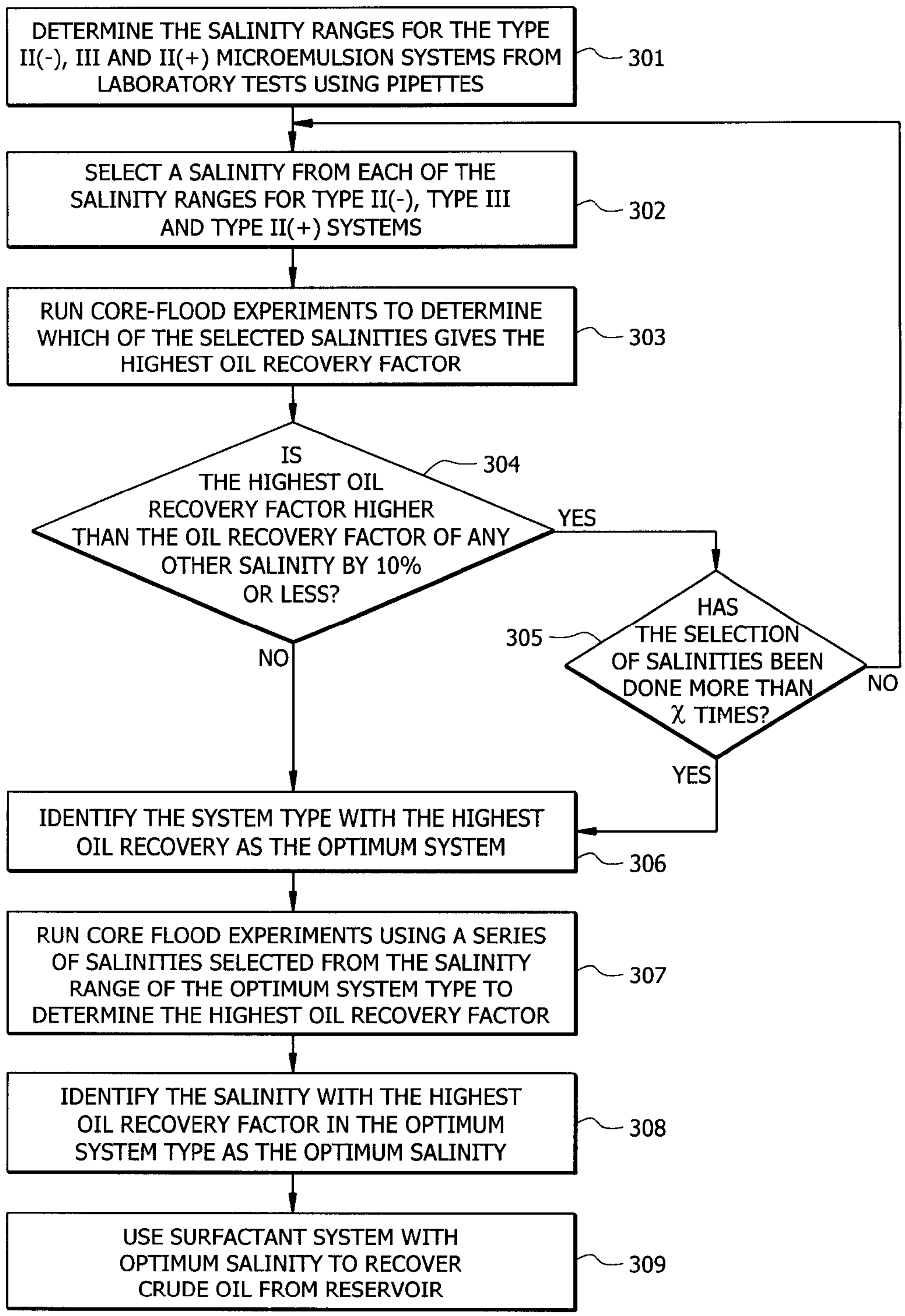
DETERMINE THE SALINITY RANGES FOR THE TYPE II(-), III AND II(+) MICROEMULSION SYSTEMS FROM LABORATORY TESTS USING PIPETTES
301
SELECT A SALINITY FROM EACH OF THE SALINITY RANGES FOR TYPE II(-), TYPE III AND TYPE II(+) SYSTEMS
302
RUN CORE-FLOOD EXPERIMENTS TO DETERMINE WHICH OF THE SELECTED SALINITIES GIVES THE HIGHEST OIL RECOVERY FACTOR
303
IS THE HIGHEST OIL RECOVERY FACTOR HIGHER THAN THE OIL RECOVERY FACTOR OF ANY OTHER SALINITY BY 10% OR LESS?
304
YES
NO
HAS THE SELECTION OF SALINITIES BEEN DONE MORE THAN χ TIMES?
305
NO
YES
IDENTIFY THE SYSTEM TYPE WITH THE HIGHEST OIL RECOVERY AS THE OPTIMUM SYSTEM
306
RUN CORE FLOOD EXPERIMENTS USING A SERIES OF SALINITIES SELECTED FROM THE SALINITY RANGE OF THE OPTIMUM SYSTEM TYPE TO DETERMINE THE HIGHEST OIL RECOVERY FACTOR
307
IDENTIFY THE SALINITY WITH THE HIGHEST OIL RECOVERY FACTOR IN THE OPTIMUM SYSTEM TYPE AS THE OPTIMUM SALINITY
308
USE SURFACTANT SYSTEM WITH OPTIMUM SALINITY TO RECOVER CRUDE OIL FROM RESERVOIR
309

FIG. 3

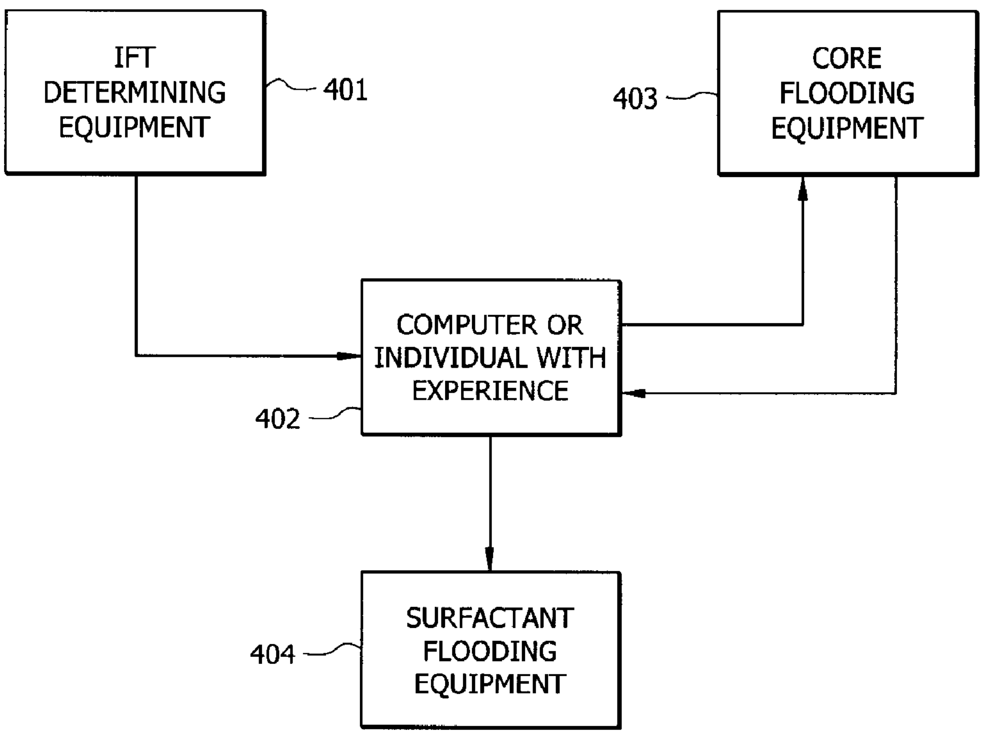
IFT DETERMINING EQUIPMENT
401
CORE FLOODING EQUIPMENT
403
COMPUTER OR INDIVIDUAL WITH EXPERIENCE
402
SURFACTANT FLOODING EQUIPMENT
404

FIG. 4

DETERMINATION OF AN ACTUAL OPTIMUM SALINITY AND AN ACTUAL OPTIMUM TYPE OF MICROEMULSION FOR SURFACTANT/POLYMER FLOODING

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application is related to co-pending application, U.S. Pat. Ser. No. XX/XXX,XXX, Attorney Docket No. 55805/P004US/10800390, filed ______, entitled "DESIGN OF OPTIMUM SALINITY PROFILE IN SURFACTANT/POLYMER FLOODING," concurrently filed herewith, the disclosure of which is incorporated herein by reference.

TECHNICAL FIELD

[0002] The present disclosure relates to the field of Enhanced Oil Recovery (EOR) from reservoirs using a surfactant system. Specifically, the disclosure relates to the determination of an actual optimum type of microemulsion. Additionally, the determination of an actual optimum salinity in surfactant/polymer flooding is disclosed.

BACKGROUND OF THE INVENTION

[0003] Petroleum (crude oil) is a finite resource that naturally occurs as a liquid in formations in the earth. Usually, crude oil is extracted by drilling wells into underground reservoirs. If the pressure of the crude oil underground is sufficient, then that pressure will cause the oil to rise to the surface. When pressure of the crude oil is sufficiently high, recovery simply involves constructing pipelines to carry the crude oil to storage facilities (e.g. tank batteries). This is known as primary recovery. If the pressure of the crude oil in the reservoir is insufficient to cause it to rise to the surface, then secondary means of recovery have to be used to recover the oil. Secondary oil recovery includes: pumping, water injection, natural gas reinjection, air injection, carbon dioxide injection or injection of some other gas into the reservoir.

[0004] The extraction of crude oil from a reservoir by conventional (primary/secondary oil) recovery technology, however, leaves behind a significant portion of the total amount of oil in that reservoir. Traditionally, the oil recovered from a reservoir, using conventional technology as compared to the total amount of oil in the reservoir, is about 33%. Thus, on average, when only conventional methods are used, approximately 67% of the oil in a reservoir is "stranded" in that reservoir. Consequently, EOR processes are used to increase crude oil recovery from reservoirs.

[0005] One method of EOR involves the use of surfactants. A surfactant is a wetting agent that lowers the interfacial tension between fluids or substances. Applied in oil recovery, surfactants reduce the interfacial tension that may prevent oil droplets from moving easily through a reservoir. The use of surfactants in aiding oil to move easily through the reservoir involves the creation of microemulsions. Microemulsions are generally clear, stable, mixtures of oil, water and surfactant, sometimes in combination with a cosurfactant. By themselves, oil and water are immiscible but when oil and water are mixed with the appropriate surfactant, the oil water and surfactant are brought into a single microemulsion phase. The microemulsion's salinity affects the microemulsion's effectiveness in enhancing the recovery of oil from a reservoir. Salinity is a measure of salt content. There are three different types of microemulsion systems used in oil recovery—Type II(−), Type III and Type II(+). The type of microemulsion system depends on the salinity in the systems.

[0006] Salinity values C_{sel} and C_{seu} define the range of each microemulsion system type. C_{sel} is the lowest salinity at which a three phase microemulsion system exists at equilibrium and C_{seu} is the highest salinity at which a three phase microemulsion system exists at equilibrium. Below C_{sel}, the system is defined as Type II(−). Above C_{seu} the system is defined as Type II(+). Between C_{sel} and C_{seu}, the system is defined as Type III. In a Type III system, the interfacial tensions (IFTs) between microemulsion and water, and microemulsion and oil are both low. The point of lowest interfacial tension is the midpoint between C_{sel} and C_{seu}. Currently, this midpoint between C_{sel} and C_{seu} is defined as the optimum salinity. Because the IFTs of microemulsion and water and microemulsion and oil are at their lowest point at this defined optimum salinity, conventional theory dictates that this salinity will be most effective in oil recovery. It is currently believed that the lower the values of the IFTs of microemulsion and water and microemulsion and oil, in a surfactant/polymer flooding system, the higher the oil recovery. Therefore, in conventional methods, the optimum salinity is determined by laboratory experiments that identify the Type III microemulsion salinity that has the lowest interfacial tension between the microemulsion and the water and oil phases, that is, the midpoint between C_{sel} and C_{seu}.

[0007] One type of laboratory experiment used to determine the Type III microemulsion salinity with the lowest interfacial tension between the microemulsion and the water and oil phases is described in U.S. Pat. No. 4,125,156, entitled "AQUEOUS SURFACTANT SYSTEMS FOR IN SITU MULTIPHASE MICROEMULSION FORMATION," the disclosure of which is incorporated herein by reference. Apart from identifying the salinity of lowest interfacial tension, this laboratory experiment may also be used to determine the salinity ranges for the three different types of microemulsion systems. As disclosed in U.S. Pat. No. 4,125,156, aqueous surfactant systems of a wide range of salinities are equilibrated with the oil in question. Equilibrations are carried out in glass-stoppered graduated cylinders, which are shaken and then allowed to sit at a constant temperature until volumetric readings remain constant with time (for example, a 24 hour period). Alternatively, equilibration may be done in pipettes or other similar laboratory equipment.

[0008] The number of phases and the volumes of these phases at equilibrium, for each salinity tested, are then recorded. Graphs of volume versus salinity are plotted. From these graphs, three regions are identified. The first region is that of intermediate salinities where three phases exist at equilibrium—(1) a micremulsion phase between (2) an oil phase and (3) a water phase. This is the region of a Type III microemulsion system with a lower boundary of C_{sel} and an upper boundary of C_{seu}. Also, the midpoint between C_{sel} and C_{seu}, can be identified from the graph. This midpoint, as mentioned before, is defined as the optimum salinity by conventional methods.

[0009] When the salinities are lower than C_{sel} (the lowest Type III salinity), the microemulsion system is known as a Type II(−) system. At these lower salinities, two phases will exist—(1) a microemulsion phase below (2) an oil phase. When the salinities are higher than C_{seu} (the highest Type III salinity) the microemulsion system is known as a Type II(+) system. At these higher salinities, two phases will exist—(1) a microemulsion phase on top of (2) a water phase.

[0010] Once the Type III and, consequently, the Type II(+) and Type II(−) system salinity ranges are determined in the laboratory, the midpoint salinity of the Type III system is used in oil recovery from reservoirs in current practice of EOR using surfactant flooding. In other words, current EOR techniques necessarily requires that oil recovery be done using Type III systems only.

BRIEF SUMMARY OF THE INVENTION

[0011] In arriving at the present invention, it was discovered that IFT is just one of several parameters that affects the oil recovery in surfactant flooding. Parameters such as relative permeability, phase trapping and adsorption, individually or in combination, may cause an actual optimum salinity of a microemulsion system to occur in any of Type II(−), Type III or Type II(+) microemulsion systems. This contrasts with the current state of the art that focuses on interfacial tension as the determining parameter and consequently that the optimum salinity is, necessarily a Type III salinity.

[0012] In accordance with embodiments of the invention, therefore, in determining an actual optimum salinity, experiments are run where the determined actual optimum salinity is a function of parameters other than but including IFT. In one embodiment, core flood experiments are run to determine the actual optimum salinity.

[0013] The foregoing has outlined rather broadly the features and technical advantages of the present invention in order that the detailed description of the invention that follows may be better understood. Additional features and advantages of the invention will be described hereinafter which form the subject of the claims of the invention. It should be appreciated by those skilled in the art that the conception and specific embodiment disclosed may be readily utilized as a basis for modifying or designing other structures for carrying out the same purposes of the present invention. It should also be realized by those skilled in the art that such equivalent constructions do not depart from the spirit and scope of the invention as set forth in the appended claims. The novel features which are believed to be characteristic of the invention, both as to its organization and method of operation, together with further objects and advantages will be better understood from the following description when considered in connection with the accompanying figures. It is to be expressly understood, however, that each of the figures is provided for the purpose of illustration and description only and is not intended as a definition of the limits of the present invention.

BRIEF DESCRIPTION OF THE DRAWINGS

[0014] For a more complete understanding of the present invention, reference is now made to the following descriptions taken in conjunction with the accompanying drawing, in which:

[0015] FIG. **1** shows recovery factors and water cuts for continuous injection cases of different microemulsion systems;

[0016] FIG. **2** shows recovery factors and water cuts for continuous injection cases of different microemulsion systems (k_{r2} increased while k_{r3} decreased);

[0017] FIG. **3** is a flow chart showing one embodiment of the current invention; and

[0018] FIG. **4** is a diagram showing one embodiment of the invention.

DETAILED DESCRIPTION OF THE INVENTION

[0019] The current state of the art of determining an optimum salinity within a Type III microemulsion system focuses on one parameter-interfacial tension. In arriving at the present invention, though it was believed that interfacial tension is an important factor in the ultimate oil recovery, it was realized that other potentially important parameters were not being taken into account in the selection of the optimum salinity type. Accordingly, it was hypothesized that if the other parameters such as relative permeability, phase trapping and adsorption, were taken into account, the actual optimum salinity determined would, often times, be other than a Type III and/or a different value from the conventional optimum salinity. Simulations of multiphase flow in surfactant flooding were conducted to determine the effect of several parameters on oil recovery factor.

[0020] The simulations were conducted on a chemical flood simulator known as the University of Texas Chemical Simulator, UTCHEM. UTCHEM is a three-dimensional, multiphase, multicomponent, numerical simulator. From the simulation results, it was discovered that taking other parameters such as relative permeability, phase trapping, adsorption, into consideration in determining an optimum salinity, may result in an optimum salinity of microemulsion system type other than a Type III system. Essentially, the simulation results show that the effect of other parameters such as relative permeability, phase trapping, and adsorption, renders the long practice of relying solely on interfacial tension as the best indicator of highest oil recovery, unreliable. The effect of one of these parameters-relative permeability—is presented in the simulation example below.

SIMULATION EXAMPLE

Input Data to UTCHEM

[0021] For the UTCHEM simulations, a fine core-scale model was used. The grid blocks used are 80×1×1 which is a 1D model. The length is 0.745 ft. Some of the reservoir and fluid properties are listed in Table 1. The base case injection scheme is 1.0 pore volume (PV) water, 0.1 PV 3 vol. % surfactant solution, 0.4 PV 0.07 wt % polymer solution, followed by 1.0 PV water injection. A pore volume is the total volume of a porous medium minus the material of the medium. In other words a pore volume is the total volume of a fluid, say oil, required to saturate the porous medium.

TABLE 1

Reservoir and Fluid Properties	
Porosity	0.3
k_H, mD	200
k_V, mD	100
Initial water saturation	0.2
Water viscosity, cP	1
Oil viscosity, cP	5
Formation water salinity, meq/ml	0.4
Assumed Surfactant data:	
Optimum salinity, meq/ml	0.365
lower salinity, meq/ml	0.345
upper salinity, meq/ml	0.385

[0022] The Microemulsion Systems Used in the Simulations

[0023] Simulations to investigate the effect of relative permeability were conducted on three salinities, each belonging to a different microemulsion system type as follows:

TABLE 2

System	Salinities
Type III	0.365 meq/ml in all injected fluids
Type II(+)	0.415 meq/ml in all injected fluids
Type II(−)	0.335 meq/ml in all injected fluids

[0024] The effect of relative permeability was investigated in two scenarios: (1) the continuous injection of surfactant and (2) the injection of a finite slug of surfactant. Each scenario will be discussed below.

Effect of Relative Permeability (k_r Curves) with Continuous Injection of Surfactant on Oil Recovery Factor

[0025] The simulations where there was continuous injection of surfactant solution was conducted without polymer. In this series of simulations, of a Type II(−), Type III and Type II(+) microemulsion system, the conventional teachings in the art would dictate that the Type III microemulsion system, would necessarily provide the highest oil recovery factor. However, as shown in FIG. **1**, the recovery factor with the Type II(+) microemulsion system is higher than the recovery factor in the Type III system. This demonstrates that oil will be more effectively displaced from an oil reservoir with a Type II(+) microemulsion system, under the above listed conditions and relative permeability k_r. There is a correlation between relative permeability and multiphase flow effect. From the foregoing, it is believed that multiphase flow effect plays an important role in determining which microemulsion system type gives the highest oil recovery factor. In general, a three-phase flow is less efficient displacement than a two-phase flow.

[0026] FIG. **1** shows that with a Type II(+) microemulsion system, water breaks through later (longer low water-cut period), than the Type III microemulsion system as illustrated by the water cut (fw). Water breakthrough occurs when water cut (fw) increases sharply. As can be seen in FIG. **1**, with the Type II(−) microemulsion system, a high aqueous phase saturation in the two-phase flow system results in the earliest water breakthrough and the lowest oil recovery at the same pore volume of injection.

[0027] To verify the hypothesis, above, regarding the multiphase effect, and to test the effect of relative permeability, the simulations for each of types Type II(−), Type III and Type II(+) microemulsion systems was repeated with the same input data except that the relative permeability of oleic (k_{r2}), was increased and the relative permeability of Type III microemulsion (k_{r3}) reduced. With a change in the relative permeability, the oil recovery factor of Type III and Type II(−) microemulsion systems increased dramatically to about the same level as the recovery for the Type II(+) microemulsion system. The new oil recovery factor as a result of a change in the relative permeabilities is shown in FIG. **2**. Comparing FIGS. **1** with **2**, it is seen that with the same phase behavior, by simply changing relative permeabilities, surfactant system performance is changed significantly.

Effect of Relative Permeabiliteis (k_r Curves) in a Finite Slug

[0028] In the simulations involving a finite slug, a 0.1 pore volume (PV) of surfactant slug is injected. The detailed injection scheme is: 1 PV water, 0.1 PV 3 vol. % surfactant, 0.4 PV 0.07 wt % polymer solution, 1.0 PV water. A constant salinity is used in all the injection fluids for a specific type of system. When the same relative permeability curves were used, the same observations as those of continuous injection were obtained regarding which type of microemulsion system would give the highest oil recovery factor. In other words, the highest oil recovery factor was observed with Type II(+) microemulsion system as shown in Table 3 below.

TABLE 3

Type	RF, %
III	84.86
II(+)	96.98
II(−)	73.4

[0029] The above set of simulations with a finite slug were repeated with the same input data except that k_{r2} is increased and k_{r3} reduced. The recovery factor for the Type III and Type II(−) microemulsion systems were increased, while the oil recovery factor for the Type II(+) microemulsion system was reduced. These simulations, therefore, illustrate that by changing the relative permeability curves, there is a change in the type of microemulsion system that gives the highest oil recovery. The oil recovery factors after reducing k_{r3} by half are shown in Table 4.

TABLE 4

Type	RF, %
III	94.49
II(+)	76.55
II(−)	90.19

Conclusion Regarding Simulations

[0030] The discovery of the effect of relative permability on the actual optimum salinity that provides the highest oil recovery in both a continuous injection scenario and a finite slug scenario led to similar simulations regarding other parameters. From these simulations, it was discovered that parameters such as relative permeability, phase trapping and adsorption, when varied, can change the actual optimum salinity and actual optimum salinity type. In arriving at the present invention, it has been proven, therefore, that the oil recovery factor, using surfactant flooding EOR, is not only a function of IFT, but also a function of many other parameters.

[0031] These parameters such as relative permeability, phase trapping, adsorption, are parameters not considered in the conventional methods of determining optimum salinity. Instead of relying solely on IFT in the identification of a Type III microemulsion system, the current invention solves this problem by running core flood experiments in each system type, preferably, in each of the three microemulsion system types or in at least two of the three microemulsion system types. A core flood experiment involves the flooding of a portion of the rock formation containing oil with a surfactant system and measuring the oil recovery factor. Core flood experiments take into account all parameters such as interfacial tension, relative permeability, phase trapping etc.

because core flood experiments are essentially a replication of the flooding process that would occur during the EOR process in the field.

Running Core Flood Experiments to Determine Actual Optimum Salinity

[0032] FIG. **3** is a flow chart showing an example of how the concepts of the present invention may be used to improve oil recovery factor from a reservoir using core flood experiments. Oil samples are taken from an oil reservoir in process **300**. In process **301**, laboratory tests using pipettes, are conducted to determine the salinity ranges of each type of Type II(−), Type II(+) and Type III microemulsion systems for the surfactant to be used in recovery of oil from the reservoir. Equipment **401** may be used to do these tests. The tests are done by preparing mixtures of the oil, water and surfactant at different salinities. These mixtures are agitated and then allowed to "sit" and equilibrate. The amount of phases that exist after allowing the mixture to come to equilibrium is recorded. Additionally, the volume of each phase is recorded. Graphs of volume versus salinity are then plotted, for example by using computer **402**, to determine the lowest salinity, C_{sel}, a three phase microemulsion system exists and the highest salinity, C_{seu}, a three phase microemulsion system exists. The salinity range of the Type III microemulsion system exists between these two points, inclusively. The Type II(−) system is the range of salinities below the Type III system and the Type II(+) system are the salinities above the Type III system.

[0033] At this point, in the overall process, it is not known which of these microemulsion system types is best for recovering oil from the reservoir in question. Therefore, to determine which microemulsion system is best for recovering oil from the reservoir, core flood experiments are run on at least one salinity of each system type. Thus, in process **302**, a salinity is selected from each of the salinity ranges of Type II (−), Type III and Type II (+). Any system for selecting a salinity from each range type may be used according to embodiments of the invention and may be done by computer **402**. For example, a salinity of 5%-30% below C_{sel} for Type II(−) or above C_{seu} for Type II(+). For Type III, the selected salinity is generally close to the average of C_{sel} and C_{seu}. It should be noted that the selected salinities are based on phase behavior data or experience. Then, core flood experiments are run, in process **303** using equipment **403**, with each of these selected salinities to determine which salinity provides the highest oil recovery factor. The core flood may be run on a sample of the rock formation containing the oil in the laboratory. The microemulsion system type with the highest oil recovery factor is identified.

[0034] In some instances, the difference in recovery factors amongst the three microemulsion system types may be so small that it remains unclear whether the microemulsion system giving the highest oil recovery factor from a single set of core flood experiments, does in fact identify the actual optimum system. Therefore, process **304** determines whether the highest recovery factors are close enough to create this uncertainty. Computer **402** can be used to make this determination. Alternatively, the determination may be made by an individual with experience. In the current example, process **304** determines whether the highest oil recovery factor of the selected salinities is higher than the oil recovery factor of any other salinity by 10% or less. In one embodiment, a predetermined percentage of 5-15% is preferred. It should be noted that instead of 10% used in process **304**, another percentage could be used, according to embodiments of the invention, to ensure the actual optimum system has been identified. If there is uncertainty that the actual optimum system has been identified, new salinities are selected from each microemulsion system type and the core flood experiments repeated. In a minority of cases, the oil recovery factors from different microemulsion systems are in fact close and thus, it would be pointless in continuing to reselect new salinities. Therefore, process **305** determines whether the selection of salinities have been done more than "x" number of times before a new selection process is started. Computer **402** may make this determination. Alternatively, the determination may be made by an individual with experience. The value of "x" may be set based on experience showing how many times on average it is necessary to reselect salinities to ensure a reliable determination of optimum system type.

[0035] When the selection process has been run at least "x" times or when it is clear that the highest recovery factor is a reliable indication of the actual optimum system type, the microemulsion system type with this highest recovery factor is identified as the actual optimum system type in process **306**. Computer **402** may make this identification. Alternatively, the identification may be made by an individual with experience. Once the actual optimum system type has been determined, the next step is to determine the actual optimum salinity within this system. This is preferable, because although at least one core flood experiment would have been done for the actual optimum microemulsion system type, the salinity tested in that experiment may not be the salinity that provides the highest oil recovery in the actual optimum microemulsion system type. Accordingly, in process **307**, further core flood experiments are run on a series of salinities selected from the actual optimum microemulsion system type.

[0036] The salinity with the highest recovery factor from the series of selected salinities is the actual optimum salinity and identified as such in process **308**. Once identified, this actual optimum salinity is used in the EOR of crude oil from the reservoir in process **309** using equipment **404**.

[0037] Although the present invention and its advantages have been described in detail, it should be understood that various changes, substitutions and alterations can be made herein without departing from the spirit and scope of the invention as defined by the appended claims. Moreover, the scope of the present application is not intended to be limited to the particular embodiments of the process, machine, manufacture, composition of matter, means, methods and steps described in the specification. As one of ordinary skill in the art will readily appreciate from the disclosure of the present invention, processes, machines, manufacture, compositions of matter, means, methods, or steps, presently existing or later to be developed that perform substantially the same function or achieve substantially the same result as the corresponding embodiments described herein may be utilized according to the present invention. Accordingly, the appended claims are intended to include within their scope, such processes, machines, manufacture, compositions of matter, means, methods, or steps.

1. A method of determining an actual optimum salinity of a surfactant system that produces an optimal recovery factor of an oil from a reservoir, said method comprising:

conducting core flood experiments for said reservoir;

determining from said core flood experiments, said actual optimum salinity, wherein said determined actual optimum salinity is a function of IFT and parameters other than IFT and wherein said core flood experiments comprises a first set of core flood experiments that are run to determine the actual optimum system type and then a second set of core flood experiments run to determine the actual optimum salinity in said actual optimum system type.

2. The method of claim **1** wherein said other parameters is selected from the list consisting of: relative permeability, phase trapping and adsorption.

3. (canceled)

4. (canceled)

5. The method of claim **1** wherein said core flood experiments, to determine the actual optimum system type, are run in each of surfactant system types, Type II(−), Type III, and Type II(+).

6. A method of determining an optimum salinity of a surfactant system that produces an optimal recovery factor of an oil, said method comprising:

determining a surfactant salinity range for each of system types Type II(−), Type III, and Type II(+) system;

selecting a plurality of salinities from each of at least two of said determined ranges of system types, wherein said determining of said salinity ranges of system types includes: experiments that measure the interfacial tension between a microemulsion and a water solution and said microemulsion and said oil;

running core flood experiments for said selected surfactant salinities to determine a highest oil recovery factor of said plurality of selected salinities;

selecting a series of surfactant system salinities from the salinity range of said system type that includes the surfactant salinity with said highest oil recovery factor; and

running core flood experiments on said series of surfactant salinities to determine an oil recovery factor for each of said selected series of surfactant salinities.

7. (canceled)

8. The method of claim **6** wherein said determining of said surfactant salinity ranges of system types includes:

experiments that equilibrate a mixture of said oil and a surfactant system and measuring the volumes of phases formed by said equilibration.

9. The method of claim **6** wherein said selecting includes:

selecting combinations from the list consisting of:

a salinity about midpoint of said Type III system, a salinity about a predetermined percentage below the lowest Type III salinity, a salinity about said predetermined percentage above the highest Type III salinity.

10. The method of claim **9** wherein said predetermined percentage is 5-30%.

11. The method of claim **6** further comprising:

identifying the optimum oil recovery factor obtained from said core flood experiments for said selected surfactant salinities.

12. The method of claim **6** further comprising:

selecting a new surfactant system salinity from each of at least two of said ranges of system types if said highest oil recovery factor of said selected salinities is within a predetermined percentage of a core flood oil recovery factor of said other selected salinities; and

running core flood experiments for said new system surfactant salinities.

13. The method of claim **12** wherein the predetermined percentage is selected from the range of 5 to 15.

14. (canceled)

15. The method of claim **6** further comprising:

identifying the surfactant system salinity of said series of salinities having the highest oil recovery as the optimum salinity.

16. A method of recovering oil from a reservoir, said method comprising:

conducting core flood experiments for said reservoir;

determining from said core flood experiments, said actual optimum salinity, wherein said determined actual optimum salinity is a function of IFT and parameters other than IFT; and

flooding said reservoir with a surfactant system of said optimum salinity, wherein said core flood experiments are run first to determine the actual optimum system type and then to determine the actual optimum salinity in said actual optimum system type.

17. The method of claim **16** wherein said other parameters is selected from the list consisting of: relative permeability, phase trapping, and adsorption.

18. (canceled)

19. (canceled)

20. The method of claim **16** wherein said core flood experiments are run in at least two surfactant system types, said surfactant system types selected from the list consisting of: Type II(−), Type III, and Type II(+) system.

21. A method of recovering oil from a reservoir, said method comprising:

flooding said reservoir with a surfactant system, the salinity of said surfactant system determined by:

determining a surfactant salinity range for each of system types Type II(−), Type III, and Type II(+) system;

selecting a plurality of salinities from each of at least two of said determined ranges of system types; and

running core flood experiments for said selected plurality of surfactant salinities to determine a highest oil recovery factor of said selected salinities;

selecting a series of surfactant salinities from the salinity range of said system type that includes the surfactant salinity with said highest oil recovery factor; and

running core flood experiments on said series of surfactant salinities to determine an oil recovery factor for each of said selected series of surfactant salinities.

22. The method of claim **21** wherein said determining of said salinity ranges of system types includes:

experiments that measure the interfacial tensions between a microemulsion and a water solution, and between said microemulsion and said oil.

23. The method of claim **21** wherein said determining of said salinity ranges of system types includes:

experiments that equilibrate a mixture of said oil and a surfactant system and measuring the volumes of phases formed by said equilibration.

24. The method of claim **21** wherein said selecting includes:

selecting combinations from the list consisting of: a salinity about midpoint of said Type III system, a salinity about 5-30% below the lowest Type III salinity, a salinity about 5-30% above the highest Type III salinity.

25. The method of claim **21** wherein said surfactant system salinity determination further comprises:

identifying the highest oil recovery factor obtained from said core flood experiments for said selected surfactant salinities.

26. The method of claim **25** wherein said surfactant system salinity determination further comprises:

selecting a new surfactant system salinity from each of at least two of said ranges of system types if said highest oil recovery factor of said selected salinities is within a predetermined percentage higher than that of a core flood oil recovery factor of said other selected salinities; and

running core flood experiments for said new surfactant salinities.

27. The method of claim **26** wherein the predetermined percentage is selected from the range of about 5 to 15.

28. (canceled)

29. The method of claim **21** wherein said surfactant system salinity determination further comprises:

identifying the salinity of said series of salinities having the highest oil recovery as the optimum salinity.

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