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### Inert fluid assays for sealed core recovery

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#### Abstract

Methods of determining if a test fluid is inert to reservoir oil at RTP, by assaying a composition, density and bubble or dew point of live oil to generate a first dataset, equilibrating a sample of live oil with a test fluid at RTP to generate an oil phase; assaying a composition, density and bubble or dew point of the oil phase to generate a second dataset; comparing the first and second datasets, wherein significant changes in the datasets indicate that the test fluid is not inert to reservoir oil at RTP. By contrast, if there are no significant changes, the test fluid is inert, and would therefore be suitable to collecting core samples at RTP. Various options for inert fluids are also provided.

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**Inventors:** Krueger; Martin C. (Houston, TX), Kelly; Shaina A. (Houston, TX), Michael; Gerald E. (Houston, TX), Simoes Correa; Thiago B. (Houston, TX), Bone; Russell (Houston, TX)

**Applicant:** CONOCOPHILLIPS COMPANY (Houston, TX)

**Family ID:** 1000008748782

**Assignee:** ConocoPhillips Company (Houston, TX)

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*Primary Examiner:* Martin; Laura

*Assistant Examiner:* Shabman; Mark A

*Attorney, Agent or Firm:* Boulware & Valoir PLLC

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## **Background/Summary**

PRIOR RELATED APPLICATIONS (1) This application claims priority to U.S. Ser. No. 63/244,953, filed Sep. 16, 2021, and incorporated by reference in its entirety for all purposes.

### **FIELD OF THE DISCLOSURE**

(1) This disclosure provides methods of testing core preservation fluids for drilling core samples and returning them to the surface in an unchanged condition.

### **BACKGROUND OF THE DISCLOSURE**

(2) One of the ways of studying rock characteristics is to drill and analyze a core sample from a reservoir. Similar to a drill bit, the rotary coring bit consists of solid metal with diamonds or tungsten for cutting at the reservoir rock, but unlike a drill bit, a rotary coring bit has a hollow center. The cutting apparatus thus surrounds the hollow center, called the core barrel, where the core sample is stored. The core barrel is made up of an inner and outer barrel separated by ball bearings, which allows the inner barrel to remain stationary and retain the core sample, while the outer barrel is rotated by the drill string and cuts the core. The core catcher is located within the core barrel and has finger-like apparatuses that move the core sample farther into the barrel and keep it from falling back into the well. After the core sample has been cut from the well, the drill string is raised, and the rotary coring bit, barrel and catcher are removed, and the core sample is retrieved. The drill bit is reattached, and drilling can commence again.

(3) However, obtaining an unaltered core sample from a reservoir with these simple prior art devices remains challenging. As the core is retrieved from deep in the reservoir, the temperature and pressure decrease which allows gases to evolve out of solution and together with free gases, expand, resulting in reservoir fluids being forced out of the core. Thus, accurate sampling, especially of fluids, is difficult, if not impossible to obtain.

(4) To address this problem, the core samples are sometimes collected and sealed in a chamber, in a method known as “pressure coring”. Pressure coring at least partially solves the problem by maintaining the core specimen at bottom-hole pressure—BHP—until the core fluids can be recovered. This concept, first proposed by Sewell in the 1930's, remained a “laboratory” tool until the late 1970's, but with the advent of ever improving technology, the method is much more popular now.

(5) However, in pressure coring the core samples are contained in an inert fluid known as FC-40 aka FLUORINERT™ which was developed for electronic uses, not uses in the petroleum industry. FC-40 is a colorless, thermally stable, fully fluorinated liquid that was believed to be inert, even at reservoir temperature and pressure (RTP). With the data presented herein, we now know that it in fact solubilizes some of the lighter fractions of oil, and thus skewing the results of high pressure core analysis. The discrepancy arises from the fact that standard testing techniques are wholly inappropriate for use with a so-called “inert” fluid developed for electronic uses, as opposed to

downhole uses.

(6) This disclosure for the first time provides assays and methodology to correctly assay downhole core samples, and further develop novel inert, high density fluids for use in obtaining and analyzing reservoir core samples.

#### SUMMARY OF THE DISCLOSURE

(7) FC-40 contains C.sub.5-18 perfluorocarbon chains, that are largely inert to electronics, but less so for petroleum, which contains short, medium, and long chain hydrocarbons. Table A provides the known FC-40 properties:

(8) TABLE-US-00001 TABLE A FC-40 1. Information on basic physical and chemical properties  
General Physical Form: Liquid Specific Physical Form: Liquid Odor, Color, Grade: Colorless, odorless liquid. Odor threshold No Data Available pH Not Applicable Melting point Not Applicable Boiling Point 158-173° C. Flash Point No flash point Evaporation rate <1 [RefStd:BUOAC = 1] Flammability (solid, gas) Not Applicable Flammable Limits(LEL) None detected Flammable Limits(UEL) None detected Vapor Pressure 3 mmHg [@ 25° C.] Vapor Density 22.5 [@ 25° C.] [Ref St: AIR = 1] Density 1.9 g/ml Specific Gravity 1.9 [RefStd:WATER = 1] Solubility in Water Nil Solubility—non-water No Data Available Partition coefficient: n-octanol water No Data Available Autoignition temperature No Data Available Decomposition temperature No Data Available Viscosity 2 centistoke [@ 25° C.] Molecular weight No Data Available Volatile Organic Compounds [Details: Exempt] Percent volatile 100% VOC Less H<sub>2</sub>O & Exempt Solvents [Details: Exempt]

(9) As is apparent, FC-40 is not particularly viscous, but is fairly dense at 1.9 g/ml. Inasmuch as electronics are concerned, it is fairly inert, but as demonstrated herein, light hydrocarbons have significant solubility in FC-40, even at atmospheric conditions, and at reservoir temperature and pressure (RTP), the problem is greatly exacerbated.

(10) Thus, what is needed in the art are test methods for correctly assaying inert fluids for downhole uses. Such assays would allow the art to develop new materials that do not dissolve light hydrocarbons but is otherwise as dense and inert to the full range of petroleum constituents, especially at RTP. In the absence of an absolute inert fluid, characterization of solubility in FC-40 and other fluids at atmospheric and at reservoir conditions will provide methods to characterize interactions within the reservoir and simulate processes under reservoir conditions.

(11) TABLE-US-00002 The invention includes any one or more of the following embodiments, any one or more of which can be combined with any other one or more in any combination(s) thereof. A method of assaying a test fluid for collecting reservoir core samples at reservoir temperature and pressure (RTP) and determining if said test fluid is inert at RTP, said method comprising: a) assaying live oil to generate a first dataset using methods comprising two or more of: i) determining a weight contribution of components of said live oil; ii) determining a bubble point of said live oil; iii) determining a density of a remaining oil when said live oil is flashed to ambient conditions; or iv) determining a weight contribution of gaseous components flashed from said live oil; b) assaying live oil plus a test fluid mixed together and equilibrated at RTP to form a hydrocarbon phase and a test fluid phase to generate a second dataset, using methods comprising two or more of: i) determining a bubble point of said hydrocarbon phase; ii) determining a weight contribution of components of said hydrocarbon phase; iii) determining a density of a remaining hydrocarbon phase when said hydrocarbon phase is flashed to standard temperature and pressure (STP) or ambient conditions; or iv) determining a weight contribution of gaseous components flashed from said hydrocarbon phase; c) comparing said first dataset and said second dataset, wherein changes in said datasets after equilibration with said test fluid indicates that said test fluid is not inert, but no changes in said datasets indicates said test fluid is inert and can be used to collect reservoir core samples at RTP. Any method described herein could also use instead of i-iv) or in addition thereto, any one or more of the following: determining total acid number (TAN), metal content, viscosity, asphaltene content, C<sub>7</sub> content; nitrogen content,

water content, carbon content, total contents; wax content; carbon residue content, conductivity, pour point, density@15° C.; salt content, sediment content, specific gravity; light end hydrocarbon content; mercaptan content; hydrogen content, total sulfur, hydrogen sulfide content or vapor pressure of said hydrocarbon phase or said remaining hydrocarbon phase. A method of assaying a test fluid for inertness in collecting reservoir core samples at RTP, said method comprising: a) obtaining an oil sample having a first characterization of elements, C1-C40 components, dissolved gas and density; b) mixing said oil sample plus a test fluid to form a mixture, and equilibrating said mixture at RTP to produce a hydrocarbon phase and a test fluid phase; c) assaying said hydrocarbon phase to determine a second characterization of elements, C1-C40 components, dissolved gas and density; d) comparing said first characterization with said second characterization to identify changes in characterization; e) wherein changes in characterization indicates that said test fluid is not inert, but no changes in characterization indicates said test fluid is inert and can be used to collect reservoir core samples at RTP. A method of determining if a test fluid is inert to reservoir oil at RTP, comprising: a) assaying a composition, density and bubble or dew point of live oil to generate a first dataset; b) equilibrating a sample of said live oil with a test fluid at RTP to generate a hydrocarbon phase; c) assaying a composition, density and bubble or dew point of said hydrocarbon phase to generate a second dataset; d) comparing said first and second datasets, wherein significant changes in said dataset indicates that said test fluid is not inert to reservoir oil at RTP. Any method herein described, wherein weight contribution is determined with gas chromatography, preferably with GC/FID, but other methods could be used including HPLC, elemental analysis, and the like. Any method herein described, wherein density of a fluid is determined using a HPHT densitometer at RTP. Any method herein described, wherein bubble point of a fluid is determined by stepping down the pressure from RTP and observing a pressure at which bubbles appear or by ASTM D2889- 95 (2019). Any method herein described, wherein RTP is an average temperature and pressure of a play in the reservoir. Although we focus on composition, density, and bubble or dew points herein, other characterization methods could also be used, e.g., measuring Acidity TAN—total acid number; metals; viscosity; asphaltene, C7; nitrogen basic; water content; carbon content; nitrogen, total content; wax content; carbon residue; phosphorous content; conductivity; pour point; density@15° C.; salt; distillation; sediments, gravity; silicon content; light end hydrocarbons; sulfur, mercaptans; hydrogen content; sulfur, total; hydrogen sulfide; vapor pressure and the like. These can be added to the characterization sets or in many cases substituted therefor. For example, in our experiments it would have sufficed to test for light ends only.

(12) As used herein, “brominated” or “fluorinated” means to replace one or more hydrogens with bromine or fluorine.

(13) As used herein, “perbrominated” or “perfluorinated” is to combine with the maximum amount of fluorine especially in place of hydrogen.

(14) As used herein, “high pressure” means higher than 1 atm, and includes all typical downhole pressures (e.g. up to and even beyond 25,000 psi).

(15) As used herein, a “high temperature” means reservoir temperatures which are greater than 100° F., typically about 200-400° F. in a reservoir.

(16) As used herein “live oil” is oil containing dissolved gas in solution that may be released from the oil solution at surface conditions. Live oil must be handled and pumped under closely controlled conditions to minimize the risk of explosion or fire.

(17) As used herein “dead oil” is oil that has been flashed to STP or ambient conditions at the surface and no longer containing very much dissolved gas.

(18) As used herein, “bubble point” or “bubble-point pressure” is defined as the temperature and pressure at which gas begins to break out of an under saturated oil and form a free gas phase in the matrix or a gas cap. In layman's terms it may be thought of as the pressure at which the first bubble of gas appears at a specific temperature. The phase diagram of typical black oils shows that the

bubble-point pressure could be different at different temperatures and pressures dependent upon many factors including gas concentration and oil composition. Often the oil is saturated with gas when discovered, meaning that the oil is holding all the gas it can at the reservoir temperature and pressure, and that it is at its bubble point. Occasionally, the oil will be undersaturated. In this case, as the pressure is lowered, the pressure at which the first gas begins to evolve from the oil is defined as the bubble point. In the petroleum industry, if bubble-point pressure value is mentioned without reference to a particular temperature, the temperature is implicitly assumed to be the reservoir temperature.

(19) As used herein, “reservoir T” or “reservoir P” or “reservoir TP” or “RTP” refer to reservoir temperature, reservoir pressure, or reservoir temperature and pressure conditions at the depth the hydrocarbon is found at. If the depth of the play is significant, an average RTP within the play can be used.

(20) As used herein, “standard TP” or “STP” is defined as a temperature of 273.15 K (0° C., 32° F.) and an absolute pressure of exactly 105 Pa (100 kPa, 1 bar). Standard temperature and pressure in the oil industry may vary, however, as standard temperature is 15° C. and pressure may vary by state regulations. Further, many use ambient conditions in the lab instead as providing for easier experiments.

(21) As used herein, “saturation pressure” is the pressure at a given temperature where the fluid goes into the two-phase region (from a one-phase region). The two-phase region may be influenced by gas concentration and oil composition at a given reservoir temperature and pressure. The vapor pressure of a liquid can be defined as the saturation pressure at ambient temperature. Inversely, the saturation pressure of a gas condensate is its dewpoint pressure. Saturation pressure is equivalent to bubble point pressure at a given pressure and temperature below the critical point. At temperatures above the critical point, the saturation pressure is equivalent to dew point until a single phase gas reservoir is reached at an upper temperature.

(22) As used herein, “zero-flash” refers to flashing a live oil sample to standard conditions in a closed loop system so that nothing escapes.

(23) The use of the word “a” or “an” in the claims or the specification means one or more than one, unless the context dictates otherwise.

(24) The term “about” means the stated value plus or minus the margin of error of measurement or plus or minus 10% if no method of measurement is indicated.

(25) The use of the term “or” in the claims is used to mean “and/or” unless explicitly indicated to refer to alternatives only or if the alternatives are mutually exclusive.

(26) The terms “comprise”, “have”, “include” and “contain” (and their variants) are open-ended linking verbs and allow the addition of other elements when used in a claim.

(27) The phrase “consisting of” is closed, and excludes all additional elements.

(28) The phrase “consisting essentially of” excludes additional material elements, but allows the inclusions of non-material elements that do not substantially change the nature of the invention.

(29) Any claim or claim element introduced with the open transition term “comprising,” may also be narrowed to use the phrases “consisting essentially of” or “consisting of,” and vice versa.

However, the entirety of claim language is not repeated verbatim in the interest of brevity herein.

(30) The following abbreviations may be used herein:

(31) TABLE-US-00003 ABBREVIATION TERM API American Petroleum Institute BHP bottom-hole pressure CCE Constant composition expansion, aka constant mass expansion (CME). The bubble point pressure is determined by an experiment called the CCE. The device used to perform this experiment is the PVT cell. CCE test is performed on a sample in a high pressure cell fitted with a glass window. In this test the cell pressure is reduced in steps and the pressure at which the first sign of gas bubbles is observed is recorded as bubble-point pressure for the oil samples and the first sign of liquid droplets is recorded as the dew-point pressure for the gas condensate samples. FC-40 a commercial inert fluid used to store cores, also known as FLUORINERT™ Not actually

inert as it dissolves lighter hydrocarbons. FID Flame Ionization detector GC Gas chromatography GOR Gas to oil ratio GTM Gas transient model HPHT High pressure, high temperature—suitable for RTP conditions. HPLC High pressure liquid chromatography P Pressure RTP Reservoir Temperature & Pressure STP Standard Temperature & Pressure TAN Total acid number TP Temperature & Pressure T Temperature PVT cell A pressure, volume, temperature cell—a vessel capable of assay at RTP.

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## Description

### BRIEF DESCRIPTION OF THE DRAWINGS

- (1) FIG. 1.1. CCE experiment on live oil at 303° F. Relative volume as a function of pressure.
- (2) FIG. 1.2. CCE experiment on live oil at 303° F. Oil compressibility as a function of pressure.
- (3) FIG. 2.1. CCE experiment of live oil/FC-40 fluid system at 303° F. Relative volume as a function of pressure.
- (4) FIG. 2.2. CCE experiment of live oil/FC-40 fluid system at 303° F. Oil/FC-40 compressibility as a function of pressure.
- (5) FIG. 3. PICTURE 1: Oil before contact with FC-40.
- (6) FIG. 4. PICTURE 2: Initial contact with FC-40.
- (7) FIG. 5. PICTURE 3: Oil/FC-40 initial interface (no mixing).
- (8) FIG. 6. PICTURE 4: Oil/FC-40 dispersion layer (no mechanical mixing).
- (9) FIG. 7. PICTURE 5: Oil/FC-40 dispersion layer 2 (no mechanical mixing).
- (10) FIG. 8. PICTURE 6: Initiate mechanical mixing.
- (11) FIG. 9. PICTURE 7: Oil/FC-40 interface fluid change during mechanical mixing.
- (12) FIG. 10. PICTURE 8: Oil/FC-40 interface after aging overnight.
- (13) FIG. 11. PICTURE 9: Oil/FC-40 interface at saturation pressure.
- (14) FIG. 12. PICTURE 10: Oil/gas interface at saturation pressure.
- (15) FIG. 13. PICTURE 11: FC-40 after flashing from cell.

### DETAILED DESCRIPTION OF THE DISCLOSURE

- (16) To further advance our sealed cell development work, an experiment was devised to understand liquid and gas phase hydrocarbon solubilities in FC-40 (FLUORINERT™). Previous accepted industry standards for oil solubilities in FC-40 (e.g., none) were established at atmospheric temperature and pressure conditions. However, due to the nature of the sealed cell acquisition and laboratory procedures, FC-40, reservoir samples and associated hydrocarbons are in contact with each other at pressures and temperatures in great excess of those used to establish the original solubility standards. Thus, we suspected that the prior data is not accurate.
- (17) To understand the temperature and pressure impact on hydrocarbon solubilities in FC-40 a number of tests at RTP were conducted, as described below. In these experiments, Eagle Ford Hunsaker B9 live oil samples with reconditioned FC-40 fluid were studied at RTP of this play (5000 psia, 303° F.). In general, the live oil is characterized before and after equilibration with FC-540 or other test fluid, and changes in the characterization indicate that the test fluid is not inert. In particular, one might see changes in density, components, bubble point, dew point and the like. In this instance, we determined that FC-40 is not inert—solubilizing some of the lighter oil components and thus changing each of these parameters.
- (18) It is common to use recycled FC-40 in the coring apparatus due to the high expense of FC-40 and in reliance on the assumption that it is inert. Depending on the program, we have requested virgin FC-40 to be used, but our initial proof of concept work was performed with used FC-40. Preparing the FC-40 as described herein ensures if the experiment is undertaken with recycled fluids the full solubility of oil in the FC-40 is measured.
- (19) FC-40 fluid obtained from previous pressure core projects was subjected to vacuum and heat



overnight to remove any previously solubilized hydrocarbon components. The FC-40 fluids from different core samples were combined and then analyzed for chemical constituency with gas chromatography with carbon disulfide (CS.sub.2) solvent with an internal standard.

(20) To obtain the composition of live oil, we flash to ambient conditions, measure the gas, the dead oil composition, and the gas to oil ratio (GOR) and calculate the live oil composition from that by adding the gas components back in. The same can be done after equilibration of test fluid, such as FC-40, at RTP and the results compared to determine if the test fluid is indeed inert.

(21) The bubble point pressure is determined by an experiment called the constant composition expansion or CCE. The CCE is done on the live oil before and after RTP equilibration with FC-40. If FC-40 is truly inert, the bubble point should not change. To perform a CCE, a known volume of live oil from a cylinder is transferred to a PVT cell. The live oil or live oil and FC-40 mixture are stabilized for 24 hours at RTP conditions. Then, an isothermal depressurization of at least 9 pressure steps is undertaken above saturation pressure. Below the bubble point pressure, a similar isothermal depressurization down to maximum expansion of the PVT cell volume is conducted. Cell volume is recorded at each pressure step. Saturation pressure is determined visually (herein we used bubble point) and graphically from the CCE experiment.

(22) In more detail, these experiments are described as follows:

(23) Fc-40 and Live Oil Mixture Study

(24) The following experimental procedures were followed, and corresponding results are included herein: 1. Measure the composition of live oil (including weight % of the components) and density (HPHT densitometer) at 5000 psi and 303° F. (RTP). 2. Perform a CCE test to determine bubble point of live oil at RTP. 3. Flash the live oil and measure the density of the remaining oil. 4. Clean the cell and charge it with 310 cc of reconditioned FC-40 and 60-cc live oil. 5. Mix. 6. Equilibrate the mixture at RTP. 7. Measure the volume of the oil phase and FC-40 phase at RTP. 8. Perform another CCE experiment to determine bubble point of the equilibrated FC-40/oil system at RTP. 9. Displace the FC-40 and flash a portion of the remaining oil phase to STP or ambient conditions to measure amount and composition of gas that leaves solution. 10. Displace the remainder of the oil phase and measure density (HPHT densitometer) and composition of the oil at STP.

(25) The reservoir fluid composition is reported in Table 1. It had a bubble point of 3547 psia at 303° F. (Table 2). Constant composition expansion at 303° F. indicated a fluid density of 0.5302 g/cc at the saturation pressure (bubble point) of 3547 psia (Table 3), and average total compressibility of  $4.227 \times 10^{-5}$  psi.sup.-1 (Table 4). Table 5 reports a constant composition expansion experiment performed on the reservoir fluid/FC-40 mix where a bubble point of 617 psia (shown in Table 6) at 303° F. was measured. The oil phase volume shrank from 60 cc at 5015 psig to 20.30 cc after mixing. FIG. 4-7 (Pictures 2-5) show the rapid diffusion of the oil into the FC-40 phase before mixing.

(26) The 20.3 cc of oil remaining was displaced and its composition measured as reported in Table 7. The FC-40 was displaced and flashed to ambient conditions; a gas phase was recovered and its composition measured and an oil phase that separated from the FC-40 also had its composition determined.

(27) The composition of the oil components that solubilized into the FC-40 was estimated in Table 8 by combining the gas and oil phases that came out of the FC-40 at ambient conditions by material balance. The material balance around the entire experiment (Table 9) indicates that the live oil composition reported in Table 8 should have more light ends. This is probably due to the fact that light hydrocarbons have significant solubility in FC-40 even at atmospheric conditions. FIG. 13 confirms that the light hydrocarbons are more soluble in FC-40, leaving the heavier components in the oil phase.

(28) Since the current standard so-called "inert" fluid (FC-40) (Table 10) removes light hydrocarbons, it would be beneficial to find a better inert fluid for downhole uses at RTP. The ideal fluid should be dense, and inert to hydrocarbons, as well as not preferentially solubilize any of the

hydrocarbon components. In addition, the solution should be reasonably safe to use, and not contribute to environmental degradation or present safety hazards.

(29) To that end, we will test silicon-based molecules that are fully substituted with fluorine, or silicon-based compounds with hydrophobic R groups, including siloxanes

(SiH.sub.3(OSiH.sub.2)nOSiH.sub.3), or silicones.

(30) Silicone fluids can be discussed in two categories: inert fluids and functional fluids.

Polydialkyl-, arylalkyl- and fluoroalkylsiloxane polymers and co-polymers, carrying no reactive (under-the-use conditions) groups, belong to the first category and may be tested as described herein.

(31) A possible test fluid is (CH.sub.3).sub.3—Si—O—Si(CH.sub.3).sub.2—O—Si(CH.sub.3)(R)—O—Si(CH.sub.3).sub.3 where (R) is hydrophobic.

(32) Another test fluid might be a fluorosyl:



(33) ##STR00001##

(34) In fact, many fluorosyls are available for testing herein, including Fluorosil 2010, Fluorosil H418, Fluorosil J15, Fluorosil L118, Fluorosil OH C7-F, Silwax F, Fluorosil OH ACR C7-F, Fluorosil TFP 1000, Fluorosil TFP 10,000, Fluorosil TFP D7, and the like.

(35) High Temperature Silicones such as Dynalene 600 or SYLTHERM (a polydimethylsiloxane liquid) may also be tested.

(36) Another option is phenylsiloxane-dimethylsiloxane copolymer and diphenylsiloxane-dimethylsiloxane copolymers. As phenyl groups replace methyl groups in a polysiloxane, several changes occur. Oxidation resistance, thermal stability, and shear resistance are enhanced.

(37) Modified silicones that have a higher density and chemical resistance and are potential candidates include:

(38) TABLE-US-00004  Viscosity Specific Refractive Modification (25° C.) gravity Index type Organic group Product name [mm/s] (25° C.) (25° C.) Features Fluoroalkyl — CH.sub.2CH.sub.2CF.sub.3 FL-5 120 0.99 1.400 Good lubricity X-22-821 120 1.09 1.390 Chemical X-22-822 100 1.15 1.384 resistance FL-100-100cs 100 1.23 1.379 Oil & FL-100-450cs 450 1.28 1.381 solvent FL-100-1,000cs 1,000 1.28 1.381 resistance FL-100-10,000cs 10,000 1.30 1.382 High specific gravity Poor solubility Good releasability Polyether-modified Viscosity Specific Refractive Modification (25° C.) gravity index type Organic group Product Name [mm/s] (25° C.) (25° C.) HLB Features Polyether —R(C.sub.2H.sub.4O).sub.a(C.sub.3H.sub.6O).sub.bR' KF-351A 70 1.06 1,450 12 Water KF-352A 1,600 1.03 1,446 7 soluble KF-353 430 1.04 1,438 10 Water KF-354L 200 1.10 1,463 16 dispersible KF-355A 150 1.07 1,453 12 Easily KF-615A 920 1.05 1,451 10 emulsifiable KF-945 130 1.00 1,420 4 Low KF-640 20 1.01 1,444 14 surface KF-642 50 1.04 1,443 12 tension KF-643 19 1.01 1,442 14 Good KF-644 38 1.02 1,446 11 permeability KF-6020 180 1.00 1,417 4 Anti- KF-6204 70 1.05 1,451 10 fogging X-22-4515 4,000 1.03 1,445 5 property Polyether —R(C.sub.2H.sub.4O).sub.a(C.sub.3H.sub.6O).sub.bR' KF-6011 130 1.07 1,450 12 Compati- (odortest) KF-6012 1,500 1.03 1,448 7 bility KF-6015 130 1.00 1,419 5 KF-6017 530 1.01 1,420 5 Phenyl-modified Viscosity Specific Refractive Modification (25° C.) gravity index type Organic group Product name [mm/s] (25° C.) (25° C.) Features Phenyl  KF-50-100cs KF-50-300cs KF-50-1,000cs KF-50-3,000cs KF-53 KF-54 X-21-3265 KF-54SS 100 300 1,000 3,000 170 400 400 500 0.995 0.996 1.00 1.00 1.06 1.07 1.07 1.07 1.427 1.427 1.427 1.427 1.485 1.505 1.505 1.504 Heat resistance High refractive index Compatibility Low-temperature resistance

(39) Brominated hydrocarbons may also work, and mercury compounds or mercury containing mixes in the manner similar to that described herein. Any of the above described or similar compounds that test as inert in the herein described tests will be used as core sampling inert fluids and/or core storage inert fluids.

(40) Suitable compounds may not be 100% inert, but the ideal solution would be 95% inert or better for the time it takes to collect core samples and test them—e.g., no more than 5% change in

content. Thus, the inert fluid should be at least 95% inert when tested with core at RTP for at least 6 hours, preferably at least 12, or even 24, 36 or 48 hours. Even more preferred is a 96, 97, 98, or 99% inertness.

(41) TABLE-US-00005 TABLE 1 Reservoir Fluid Composition Flashed Gas Flashed Oil Reservoir Fluid Mole Mole Wt Molecular Specific Mole Wt Component % % % Weight Gravity % % Nitrogen N.sub.2 0.237 0.000 0.000 28.01 0.8100 0.171 0.067 Carbon Dioxide CO.sub.2 1.028 0.000 0.000 44.01 0.8270 0.741 0.458 Hydrogen Sulphide H.sub.2S 0.000 0.000 0.000 34.08 0.7960 0.000 0.000 Methane C.sub.1 68.722 0.074 0.006 16.05 0.3000 49.593 11.181 Ethane C.sub.2 14.516 0.325 0.051 30.07 0.3560 10.562 4.461 Propane C.sub.3 8.004 0.701 0.161 44.10 0.5010 5.969 3.698 i-Butane i-C.sub.4 1.340 0.326 0.099 58.12 0.5570 1.057 0.863 n-Butane n-C.sub.4 2.879 1.365 0.413 58.12 0.5790 2.457 2.006 i-Pentane i-C.sub.5 1.190 1.426 0.535 72.15 0.6200 1.256 1.273 n-Pentane n-C.sub.5 0.990 2.217 0.832 72.15 0.6260 1.332 1.350 Hexanes C.sub.6 0.708 5.727 2.504 84.00 0.6900 2.106 2.486 Heptanes C.sub.7 0.182 8.002 3.957 95.00 0.7270 2.361 3.151 Octanes C.sub.8 0.106 10.632 5.921 107.00 0.7490 3.039 4.568 Nonanes C.sub.9 0.091 9.451 5.952 121.00 0.7680 2.699 4.588 Decanes C.sub.10 0.007 7.451 5.274 136.00 0.7820 2.081 3.977 Undecanes C.sub.11 0.000 5.945 4.611 149.00 0.7930 1.657 3.467 Dodecanes C.sub.12 0.000 4.796 4.069 163.00 0.8040 1.337 3.060 Tridecanes C.sub.13 4.593 4.207 176.00 0.8150 1.280 3.164 Tetradecanes C.sub.14 3.952 3.929 191.00 0.8260 1.101 2.955 Pentadecanes C.sub.15 3.579 3.856 207.00 0.8360 0.997 2.900 Hexadecanes C.sub.16 2.906 3.343 221.00 0.8430 0.810 2.514 Heptadecanes C.sub.17 2.617 3.228 237.00 0.8510 0.729 2.428 Octadecanes C.sub.18 2.468 3.199 249.00 0.8560 0.688 2.406 Nonadecanes C.sub.19 2.301 3.125 261.00 0.8610 0.641 2.350 Eicosanes C.sub.20 1.897 2.715 275.00 0.8660 0.529 2.042 Heneicosanes C.sub.21 1.718 2.584 289.00 0.8710 0.479 1.943 Docosanes C.sub.22 1.485 2.342 303.00 0.8760 0.414 1.761 Tricosanes C.sub.23 1.354 2.234 317.00 0.8810 0.377 1.680 Tetracosanes C.sub.24 1.220 2.102 331.00 0.8850 0.340 1.581 Pentacosanes C.sub.25 1.086 1.949 345.00 0.8880 0.302 1.466 Hexacosanes C.sub.26 1.011 1.890 359.00 0.8920 0.282 1.421 Heptacosanes C.sub.27 0.914 1.775 373.00 0.8960 0.255 1.335 Octacosanes C.sub.28 0.834 1.680 387.00 0.8990 0.232 1.264 Nonacosanes C.sub.29 0.750 1.562 400.00 0.9020 0.209 1.174 Tricontanes C.sub.30 0.665 1.436 415.00 0.9050 0.185 1.080 Hentriacontanes C.sub.31 0.579 1.292 429.00 0.9090 0.161 0.972 Dotriacontanes C.sub.32 0.550 1.269 443.00 0.9120 0.153 0.955 Tritriacontanes C.sub.33 0.499 1.187 457.00 0.9150 0.139 0.893 Tetratriacontanes C.sub.34 0.488 1.197 471.00 0.9170 0.136 0.900 Pentatriacontanes C.sub.35 0.404 1.020 485.00 0.9200 0.113 0.767 Hexatriacontanes plus C36+ 3.693 12.494 650.00 0.9913 1.029 9.396 100.00 100.00 100.00 100.00 Molecular Weight 24.47 192.13 71.19 Compositional Grouping and Plus Fraction Properties Group Mol % wt % MW Density C7+ 24.76 72.16 207.49 0.8461 C12+ 12.92 52.41 255.79 0.8758 C20+ 5.34 30.63 408.67 0.9195 C30+ 1.92 14.96 555.73 0.9605 C36+ 1.03 9.40 650.00 0.9913

(42) TABLE-US-00006 TABLE 2 Main PVT Results TEST CONDITIONS Pressure 5000 psia Temperature 303.0 F. CONSTANT COMPOSITION EXPANSION @ 303.0 F. Saturation Pressure (Bubble Point) 3547.31 psia Compressibility @ Saturation Pressure 4.2274E-05 psia.sup.-1 SEPARATOR FLUID FLASH TEST TO AMBIENT CONDITIONS At Saturation Pressure Oil Formation Volume Factor 2.0052 res.bbl/STB Flash Gas-Oil Ratio 1432.89 scf/STB At Tank Conditions Residual Oil Density 0.7996 g/cm.sup.3 API Gravity 45.47 Measured MW 195.30 Cylinder Number: 832808 Volume of oil left: 300 cc at 5000 psi and 303 F.

(43) TABLE-US-00007 TABLE 3 Constant Composition Expansion @ 303.0 F. Pressure Relative Volume Y-Fuaction Fluid Density Liquid Volume (psia) [1] [2] (g/cc) [3] Vliq/Vb % 7015 0.9059 0.5853 6515 0.9146 0.5797 6015 0.9244 0.5736 5515 0.9354 0.5668 5015 0.3480 0.5593 4515 0.9627 0.5598 4015 0.9862 0.5409 3547 Psat 1.0000 0.5302 100.000 3379 1.0251 1.9791 94.430 3211 1.6541 1.9339 90.836 3043 1.0877 1.8886 88.819 2875 1.1268 1.8434 85.321 2707 1.1725 1.7982 82.849 2539 1.2265 1.7530 89.754 2371 1.2964 1.7077 78.589 2293 1.3669 1.6625 76.583 2935 1.4593 1.6173 74.507 1867 1.5723 1.5721 72.604 1599 1.7123 1.5268 70.898 1531

1.8886 1.4816 69.2571363 2.1153 1.4364 67.744 1195 2.4144 1.3912 65.998 1027 2.8225 1.3459 64.600 [1] Volume at indicated pressure per volume at saturation pressure [2] Y Function =  $((P_{sat} - P)/P)(\text{Relative Volume} - 1)$  [3] Measured by HPHT densfometer  $P_{sat}$ —Saturation Pressure

(44) TABLE-US-00008 TABLE 4 Constant Composition Expansion @ 303.0 F. Oil Compressibility as a Function of Pressure Average Pressure Range Total From To Compressibility (psia) (psia) (psi.sup.-1) 7015 6515 1.903E-05 6515 6015 2.111E-05 6015 5515 2.357E-05 5515 5015 2.657E-05 5015 4515 3.049E-05 4515 4015 3.579E-05 4015 3547  $P_{sat}$  4.227E-05

(45) TABLE-US-00009 TABLE 5 Constant Composition Expansion of Live Oil/FC-40 Fluid System @ 303.0 F. Total Relative Gas Phase Oil Phase Pressure Volume Volume Y-Function Volume Volume (psia) cc [1] [2] cc cc 5015 374.01 0.8822 20.30 4015 380.25 0.8969 20.61 3015 387.90 0.9149 20.64 2515 392.72 0.9263 20.54 2015 398.36 0.9396 20.54 1515 405.22 0.9558 20.59 1015 414.00 0.9765 20.67 617  $P_{sat}$  423.96 1.0000 0.0000 20.05 606 427.51 1.0084 2.165 6.444 19.79 595 431.73 1.0183 2.017 9.485 19.51 584 435.99 1.0284 1.991 13.961 19.23 573 446.30 1.0385 1.992 20.549 18.96 562 445.19 1.0501 1.954 28.527 18.78 551 451.63 1.0653 1.835 33.881 18.86 540 458.16 1.0807 1.767 40.240 18.93 529 464.79 1.0963 1.727 47.793 19.01 516 471.51 1.1122 1.704 56.762 19.08 507 478.70 1.1291 1.680 63.983 19.29 496 486.12 1.1466 1.664 70.907 19.55 485 493.67 1.1644 1.655 78.580 19.81 474 501.32 1.1825 1.653 87.084 20.07 463 508.66 1.1998 1.665 95.880 20.00 452 514.58 1.2138 1.708 103.248 18.80 Loading Information (5000 psig & 303° F.) Reservoir Oil, cc 60.00 FC-40, cc 314.01 [1] Volume at indicated pressure per volume at saturation pressure [2] Y Function =  $(P_{sat} - P)/P)/(\text{Relative Volume} - 1)$   $P_{sat}$ —Saturation Pressure

(46) TABLE-US-00010 TABLE 6 Constant Composition Expansion of Live Oil/FC-40 Fluid System @ 303.0 F. Live Oil/ FC-40 Fluid System Compressibility as a Function of Pressure Average Pressure Range Total From To Compressibility (psia) (psia) (psi.sup.-1) 5015 4015 1.655E-05 4015 3015 1.991E-05 3015 2515 2.468E-05 2515 2015 2.854E-05 2015 1515 3.417E-05 1515 1015 4.286E-05 1015 617  $P_{sat}$  5.971E-05

(47) TABLE-US-00011 TABLE 7 Displaced Oil Phase Composition (After mixing with FC-40 in the PVT cell) Flashed Gas Flashed Oil Oil Phase Mole Mole Wt Molecular Specific Mole Wt Component % % % Weight Gravity % % Nitrogen N.sub.2 2.910 0.000 0.000 28.01 0.8100 0.686 0.089 Carbon Dioxide CO.sub.2 0.805 0.000 0.000 44.01 0.8270 0.190 0.038 Hydrogen Sulphide H.sub.2S 0.000 0.000 0.000 34.08 0.7960 0.000 0.000 Methane C.sub.1 66.763 0.015 0.001 16.05 0.3000 15.742 1.165 Ethane C.sub.2 16.474 0.191 0.021 30.07 0.3560 4.028 0.559 Propane C.sub.3 8.075 0.651 0.104 44.10 0.5010 2.400 0.488 i-Butane i-C.sub.4 1.050 0.290 0.061 58.12 0.5570 0.469 0.126 n-Butane n-C.sub.4 2.180 1.035 0.218 58.12 0.5790 1.304 0.350 i-Pentane i-C.sub.5 0.603 0.772 0.201 72.15 0.6200 0.732 0.244 n-Pentane n-C.sub.5 0.572 1.109 0.290 72.15 0.6260 0.983 0.327 Hexanes C.sub.6 0.392 2.377 0.722 84.00 0.6900 1.909 0.739 Heptanes C.sub.7 0.110 3.547 1.219 95.00 0.7270 2.737 1.199 Octanes C.sub.8 0.045 6.466 2.503 107.00 0.7490 4.953 2.444 Nonanes C.sub.9 0.018 4.824 2.111 121.00 0.7680 3.691 2.060 Decanes C.sub.10 0.002 4.317 2.124 136.00 0.7820 3.301 2.070 Undecanes C.sub.11 0.000 3.864 2.083 149.00 0.7930 2.954 2.029 Dodecanes C.sub.12 0.000 3.538 2.086 163.00 0.8040 2.705 2.033 Tridecanes C.sub.13 3.785 2.410 176.00 0.8150 2.893 2.348 Tetradecanes C.sub.14 3.645 2.519 191.00 0.8260 2.786 2.454 Pentadecanes C.sub.15 3.675 2.752 207.00 0.8360 2.809 2.681 Hexadecanes C.sub.16 3.332 2.664 221.00 0.8430 2.547 2.596 Heptadecanes C.sub.17 3.256 2.791 237.00 0.8510 2.488 2.720 Octadecanes C.sub.18 3.275 2.950 249.00 0.8560 2.504 2.875 Nonadecanes C.sub.19 3.338 3.152 261.00 0.8610 2.552 3.071 Eicosanes C.sub.20 2.984 2.969 275.00 0.8660 2.281 2.893 Heneicosanes C.sub.21 2.884 2.584 289.00 0.8710 2.205 2.938 Docosanes C.sub.22 2.655 2.910 303.00 0.8760 2.029 2.835 Tricosanes C.sub.23 2.556 2.931 317.00 0.8810 1.954 2.856 Tetracosanes C.sub.24 2.422 2.900 331.00 0.8850 1.852 2.826 Pentacosanes C.sub.25 2.252 2.811 345.00 0.8880 1.722 2.739 Hexacosanes C.sub.26 2.186 2.839 359.00 0.8920 1.671 2.766 Heptacosanes C.sub.27 2.053 2.770 373.00 0.8960 1.569 2.699 Octacosanes C.sub.28 1.925 2.695

387.00 0.8990 1.472 2.626 Nonacosanes C.sub.29 1.775 2.569 400.00 0.9020 1.357 2.503  
 Tricontanes C.sub.30 1.649 2.476 415.00 0.9050 1.260 2.412 Hentriacontanes C.sub.31 1.458  
 2.263 429.00 0.9090 1.114 2.205 Dotriacontanes C.sub.32 1.426 2.285 443.00 0.9120 1.090 2.226  
 Tritriacontanes C.sub.33 1.297 2.144 457.00 0.9150 0.992 2.089 Tetratriacontanes C.sub.34 1.294  
 2.204 471.00 0.9170 0.989 2.148 Pentatriacontanes C.sub.35 1.175 2.062 485.00 0.9200 0.898  
 2.009 Hexatriacontanes plus C.sub.36+ 10.706 25.174 650.00 0.9913 8.183 24.528 100.00 100.00  
 100.00 100.00 Calculated MW 23.63 276.43 216.86 Compositional Grouping and Plus Fraction  
 Properties Group Mol % wt % MW Density C7+ 71.56 95.88 290.57 0.8882 C12+ 53.92 86.07  
 324.97 0.8985 C20+ 32.64 65.30 433.88 0.9280 C30+ 14.53 37.62 561.56 0.9625 C36+ 8.18 24.53  
 650.00 0.9913 Zero Flash Results (5000 psig & 303 F.) Live oil density, g/cc 0.8883 GOR, scf/stb  
 125.02 Flashed oil density, g/cc 0.8429 Flashed oil MW 287.60  
 (48) TABLE-US-00012 TABLE 8 Oil Phase in Solution in FC-40 Composition (After mixing with  
 FC-40 in the PVT cell) Flashed Gas Flashed Oil Live Oil\* Mole Mole Wt Molecular Specific Mole  
 Wt Component % % % Weight Gravity % % Nitrogen N.sub.2 0.986 0.000 0.000 28.01 0.8100  
 0.851 0.568 Carbon Dioxide CO.sub.2 1.017 0.000 0.000 44.01 0.8270 0.877 0.920 Hydrogen  
 Sulphide H.sub.2S 0.000 0.000 0.000 34.08 0.7960 0.000 0.000 Methane C.sub.1 69.727 0.015  
 0.002 16.05 0.3000 60.150 22.996 Ethane C.sub.2 14.149 0.132 0.026 30.07 0.3560 12.223 8.756  
 Propane C.sub.3 7.522 0.526 0.149 44.10 0.5010 6.561 6.893 i-Butane i-C.sub.4 1.181 0.327 0.122  
 58.12 0.5570 1.064 1.473 n-Butane n-C.sub.4 2.536 1.325 0.496 58.12 0.5790 2.372 3.284 i-  
 Pentane i-C.sub.5 0.943 1.391 0.646 72.15 0.6200 1.004 1.726 n-Pentane n-C.sub.5 0.858 2.105  
 0.978 72.15 0.6260 1.029 1.769 Hexanes C.sub.6 0.703 5.548 3.000 84.00 0.6900 1.369 2.739  
 Heptanes C.sub.7 0.228 8.537 5.220 95.00 0.7270 1.370 3.100 Octanes C.sub.8 0.104 16.177  
 11.142 107.00 0.7490 2.312 5.894 Nonanes C.sub.9 0.031 11.577 9.017 121.00 0.7680 1.617 4.662  
 Decanes C.sub.10 0.009 9.473 8.293 136.00 0.7820 1.309 4.242 Undecanes C.sub.11 0.003 7.563  
 7.254 149.00 0.7930 1.042 3.697 Dodecanes C.sub.12 0.000 5.865 6.154 163.00 0.8040 0.806  
 3.129 Tridecanes C.sub.13 5.296 6.000 176.00 0.8150 0.728 3.051 Tetradecanes C.sub.14 4.225  
 5.194 191.00 0.8260 0.580 2.641 Pentadecanes C.sub.15 3.555 4.736 207.00 0.8360 0.488 2.408  
 Hexadecanes C.sub.16 2.653 3.773 221.00 0.8430 0.364 1.919 Heptadecanes C.sub.17 2.208 3.368  
 237.00 0.8510 0.303 1.712 Octadecanes C.sub.18 1.936 3.103 249.00 0.8560 0.266 1.578  
 Nonadecanes C.sub.19 1.665 2.797 261.00 0.8610 0.229 1.422 Eicosanes C.sub.20 1.264 2.237  
 275.00 0.8660 0.174 1.137 Heneicosanes C.sub.21 1.058 1.968 289.00 0.8710 0.145 1.001  
 Docosanes C.sub.22 0.840 1.639 303.00 0.8760 0.115 0.833 Tricosanes C.sub.23 0.710 1.449  
 317.00 0.8810 0.098 0.737 Tetracosanes C.sub.24 0.589 1.255 331.00 0.8850 0.081 0.638  
 Pentacosanes C.sub.25 0.463 1.074 345.00 0.8880 0.066 0.546 Hexacosanes C.sub.26 0.414 0.957  
 359.00 0.8920 0.057 0.487 Heptacosanes C.sub.27 0.353 0.848 373.00 0.8960 0.049 0.431  
 Octacosanes C.sub.28 0.289 0.719 387.00 0.8990 0.040 0.366 Nonacosanes C.sub.29 0.250 0.644  
 400.00 0.9020 0.034 0.327 Tricontanes C.sub.30 0.212 0.566 415.00 0.9050 0.029 0.288  
 Hentriacontanes C.sub.31 0.159 0.440 429.00 0.9090 0.022 0.224 Dotriacontanes C.sub.32 0.153  
 0.437 443.00 0.9120 0.021 0.222 Tritriacontanes C.sub.33 0.129 0.379 457.00 0.9150 0.018 0.193  
 Tetratriacontanes C.sub.34 0.120 0.365 471.00 0.9170 0.017 0.186 Pentatriacontanes C.sub.35  
 0.106 0.332 485.00 0.9200 0.015 0.169 Hexatriacontanes plus C.sub.36+ 0.770 3.220 650.00  
 0.9913 0.106 1.637 100.00 100.00 100.000 100.000 Calculated MW 23.92 155.35 41.978  
 \*Estimated based on mass balance calculation. Compositional Grouping and Plus Fraction  
 Properties Group Mol % wt % MW Density C7+ 12.50 48.88 164.13 0.8116 C12+ 4.85 27.28  
 205.31 0.8465 C20+ 1.09 9.42 364.35 0.9026 C30+ 0.23 2.92 540.45 0.9549 C36+ 0.11 1.64  
 650.00 0.9913 Zero Flash Results (5000 psig & 303 F.) GLR\*, scf/stb 152.40 Flashed liquid  
 density\*, g/cc 1.8500 \*Liquid is mixture of live oil and FC-40 \*FC-40 fluid density at STP  
 (49) TABLE-US-00013 TABLE 9 Material Balance Calculation Basis for Table 8 INITIAL  
 VOLUMETRIC CONDITIONS Pressure: 5015 psia Temperature: 303.0 F. Reservoir fluid volume:  
 60.00 cc 0.4714 mole Reservoir fluid density: 0.5593 g/cc Displaced oil volume: 20.30 cc 0.0832

mole Displaced oil density: 0.8883 g/cc Oil phase in solution + FC-40: 353.71 cc 0.3882 mole OIL  
 PHASE IN SOLUTION + FC-40 FLASH TEST VOLUMETRICS Total flashed volume: 20.84 cc  
 5015 psia & 303 F. Gas volume collected: 467.51 cc 14.696 psia & 60 F. Total Gas in solution  
 (scaled) 7933.78 cc 0.3349 mole Dead oil in solution by material 0.0533 mole balance  
 (50) TABLE-US-00014 TABLE 10 FC-40 Preparation Composition Mole Wt Molecular Specific  
 Component % % Weight Gravity Nitrogen N.sub.2 0.000 0.000 28.01 0.8100 Carbon Dioxide  
 CO.sub.2 0.000 0.000 44.01 0.8270 Hydrogen Sulphide H.sub.2S 0.000 0.000 34.08 0.7960  
 Methane C.sub.1 0.000 0.000 16.05 0.3000 Ethane C.sub.2 0.042 0.017 30.07 0.3560 Propene  
 C.sub.3 0.033 0.019 44.10 0.5010 i-Butane i-C.sub.4 0.000 0.000 58.12 0.5570 n-Butane n-C.sub.4  
 0.000 0.000 58.12 0.5790 i-Pentane i-C.sub.5 0.000 0.000 72.15 0.6200 n-Pentane n-C.sub.5 0.000  
 0.000 72.15 0.6260 Carbon Disulfide CS.sub.2 99.910 99.944 76.13 n/a Hexanes C.sub.6 0.000  
 0.000 84.00 0.6900 Heptanes C.sub.7 0.000 0.000 95.00 0.7270 Octanes C.sub.8 0.016 0.020  
 107.00 0.7490 Nonanes C.sub.9 0.000 0.000 121.00 0.7680 Decanes C.sub.10 0.000 0.000 136.00  
 0.7820 Undecanes C.sub.11 0.000 0.000 149.00 0.7930 Dodecanes C.sub.12 0.000 0.000 163.00  
 0.8040 Tridecanes C.sub.13 0.000 0.000 176.00 0.8150 Tetradecanes C.sub.14 0.000 0.000 191.00  
 0.8260 Pentadecanes C.sub.15 0.000 0.000 207.00 0.8360 Hexadecanes C.sub.16 0.000 0.000  
 221.00 0.8430 Heptadecanes C.sub.17 0.000 0.000 237.00 0.8510 Octadecanes C.sub.18 0.000  
 0.000 249.00 0.8560 Nonadecanes C.sub.19 0.000 0.000 261.00 0.8610 Eicosanes C.sub.20 0.000  
 0.000 275.00 0.8660 Heneicosanes C.sub.21 0.000 0.000 289.00 0.8710 Docosanes C.sub.22 0.000  
 0.000 303.00 0.8760 Tricosanes C.sub.23 0.000 0.000 317.00 0.8810 Tetracosanes C.sub.24 0.000  
 0.000 331.00 0.8850 Pentacosanes C.sub.25 0.000 0.000 345.00 0.8880 Hexacosanes C.sub.26  
 0.000 0.000 359.00 0.8920 Heptacosanes C.sub.27 0.000 0.000 373.00 0.8960 Octacosanes  
 C.sub.28 0.000 0.000 387.00 0.8990 Nonacosanes C.sub.29 0.000 0.000 400.00 0.9020 Tricontanes  
 C.sub.30 0.000 0.000 415.00 0.9050 Hentriacontanes C.sub.31 0.000 0.000 429.00 0.9090  
 Dotriacontanes C.sub.32 0.000 0.000 443.00 0.9120 Tritriacontanes C.sub.33 0.000 0.000 457.00  
 0.9150 Tetatriacontanes C.sub.34 0.000 0.000 471.00 0.9170 Pentatriacontanes C.sub.35 0.000  
 0.000 485.00 0.9200 Hexatriacontanes plus C.sub.36+ 0.000 0.000 650.00 0.9913 100.00 100.00  
 Weight of Sample Used 0.8401 g Internal Standard Added 0.0095 g

## Claims

1. A method of assaying a test fluid for collecting reservoir core samples at reservoir temperature and pressure (RTP) and determining if said test fluid is inert at RTP, said method comprising: a) assaying a live oil to generate a first dataset using methods comprising at least one of: i) determining a weight contribution of components of said live oil; ii) determining a bubble point of said live oil; iii) determining a density of a remaining oil when said live oil is flashed to standard temperature and pressure (STP) or ambient conditions; iv) determining a weight contribution of gaseous components flashed from said live oil; or v) determining total acid number (TAN), metal content, viscosity, asphaltene content, C7 content, nitrogen content, water content, carbon content, total contents, wax content, carbon residue content, conductivity, pour point, density at 15° C., salt content, sediment content, specific gravity, light end hydrocarbon content, mercaptan content, hydrogen content, total sulfur, hydrogen sulfide content or vapor pressure of said hydrocarbon phase or said remaining hydrocarbon phase; b) assaying said live oil plus a test fluid mixed together and equilibrated at RTP to form hydrocarbon phase and a test fluid phase to generate a second dataset, using methods comprising at least one of: i) determining a bubble point of said hydrocarbon phase; ii) determining a weight contribution of components of said hydrocarbon phase; iii) determining a density of a remaining hydrocarbon phase when said hydrocarbon phase is flashed to STP or ambient conditions; iv) determining a weight contribution of gaseous components flashed from said hydrocarbon phase; or v) determining total acid number (TAN), metal content, viscosity, asphaltene content, C7 content, nitrogen content, water content, carbon content, total

- contents, wax content, carbon residue content, conductivity, pour point, density at 15° C., salt content, sediment content, specific gravity, light end hydrocarbon content, mercaptan content, hydrogen content, total sulfur content, hydrogen sulfide content or vapor pressure of said hydrocarbon phase or said remaining hydrocarbon phase; c) comparing said first dataset and said second dataset, wherein changes in said second dataset compared with said first dataset indicates that said test fluid is not inert, but no changes indicates said test fluid is inert and can be used to collect reservoir core samples at RTP.
2. The method of claim 1, wherein the weight contribution is determined with gas chromatography.
  3. The method of claim 1, wherein the weight contribution of components of any fluid is determined with elemental composition and gas chromatography.
  4. The method of claim 1, wherein the weight contribution of gaseous components is determined with gas chromatography.
  5. The method of claim 1, wherein the weight contribution of components of any fluid is determined with elemental composition and gas chromatography with flame ionization detector (GC/FID).
  6. The method of claim 1, wherein the density is determined using a High Pressure High Temperature (HPHT) densitometer at RTP.
  7. The method of claim 1, wherein the bubble point is determined by stepping down the pressure from RTP and observing a pressure at which bubbles appear.
  8. The method of claim 1, wherein the bubble point is determined by ASTM D2889-95 (2019).
  9. The method of claim 1, wherein the RTP is an average temperature and pressure of a play in the reservoir.
  10. The method of claim 1, wherein step a) and step b) assaying includes characterization of elements, C1-C40 components, the bubble point and the density.
  11. The method of claim 10, wherein said characterization of elements and C1-C40 components are determined with elemental composition and gas chromatography.
  12. The method of claim 10, wherein said characterization of elements and C1-C40 components are determined by elemental composition and gas chromatography with flame ionization detector (GC/FID).
  13. The method of claim 10, wherein the density is determined using a High Pressure High Temperature (HPHT) densitometer at RTP.
  14. The method of claim 10, wherein the bubble point is determined by stepping down a pressure from RTP and observing a pressure at which bubbles form.
  15. The method of claim 10, wherein the bubble point is determined by ASTM D2889-95 (2019).
  16. The method of claim 10, wherein the RTP is an average temperature and pressure of a play in the reservoir.
  17. The method of claim 1, wherein step a) and step b) include assaying a composition, the density at 15° C., and the bubble point.
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