

METHOD TO ENHANCE THE PRODUCTION CAPACITY OF AN OIL WELL

Cross-Reference To Related Applications

This application claims priority to a United States Provisional Application having Serial No. 61/230,641 filed July 31, 2009, which is hereby incorporated herein by reference.

Field Of The Invention

The invention relates to a composition and method to enhance the production capacity of an oil well.

Background Of The Invention

With ever increasing environmental pressures being placed on the oil industry it has become necessary to develop and employ products and methods of well treatment which can perform in a timely fashion, be cost effective and conform to the stricter controls now in place.

It is known in the art that oil fields can become extremely viscous due to a heavy concentration of paraffin and asphaltene in the formation. These deposits can result in reduced oil production, fouling of flow lines and down hole tubing, under deposit corrosions, reductions in gas production, and increased pumping costs due to pumping a high viscosity fluid. Each of these conditions individually can result in lost revenue. The combination of two or more of these conditions will lead to a significant revenue loss to the well owner, as well as additional income spent due to clean up of oil spills caused by under deposit corrosion. Moreover, the differing oxygen concentrations in bulk oil with respect to the oxygen levels extant beneath the deposit result in localized, rapid corrosion of the piping and eventual oil leaks.

A number of methods are known in the art to remove some or all of blockage materials. One of the most frequent methods of paraffin reduction utilized in down hole treatment is often referred to as "Hot Oiling". Using this prior art method, heated refined oil (10-100 barrels) is pumped directly down the hole to re-liquefy the paraffin and clear the flow tube. Hopefully, some of the oil reaches the formation and also clears some of the fissures of paraffin theoretically resulting in increased production rates for a short period of time, generally from about 1 to about 7 days.

In actuality, much of the costly refined heated oil may not be recovered and the positive effects of this method may only be seen for a very short time with no guarantee of increased well performance. The paraffin material that reforms typically comprises a much harder and tighter matrix than the original deposit, and is much more difficult to remove, particularly if calcium salts comprise part of the paraffin composition. Typically "Hot Oiling" applications will be performed one to two times per month. This method can be very expensive because the costs include heating, refining, trucking, manpower, and the cost of the lost down hole oil.

Other prior art methods utilize toluene and/or xylene to re-liquefy the paraffin and thick oil to a less viscous material. Typical applications of this product use from 20 barrels to 100 barrels down hole at a typical cost of \$3.00 per gallon of product. This method re-liquefies the paraffin's using one or more volatile, very dangerous, cancer causing chemicals. These products potentially pollute the ground water and must be handled with extreme caution. The paraffin and thick oil revert to their original state once these products have revolatilized causing deposits in flow lines or storage tank "dropout".

"Hot watering" is probably the least expensive and potentially least effective prior art method of paraffin removal. Hot water is injected directly down hole to remove paraffin from the walls of the tubing. This method typically treats just the tubing and not much of the formation itself. Some short-term benefits can be seen but typically the results are seen for only a day or two.

Certain prior art methods utilize a 15% muriatic acid solution to remove paraffin. This method may appear cost effective, however the muriatic acid will attack the mild steel piping and greatly accelerate corrosion rates, reduce pipe wall thickness, and result in holes in the down hole tubing.

Summary of Invention

A method to increase oil production from an oil well comprising a plurality of production zones is presented. The method selects a production zone, isolates that selected production zone, and reconfigures flow lines to allow direct injection of materials under pressure into the selected production zone.

The method determines a treatment pressure based upon soil porosity in the selected production zone, injects a brine solution into the selected production zone at

the selected pressure, and maintains the selected pressure in the selected production zone for at least 72 hours.

A method to increase an oil cut oil percentage produced from an oil well comprising a plurality of production zones is presented. The method selects a production zone, isolates that selected production zone, and reconfigures flow lines to allow direct injection of materials under pressure into the selected production zone.

The method determines a treatment pressure based upon soil porosity in the selected production zone, injects a brine solution into the selected production zone at the selected pressure, and maintains the selected pressure in the selected production zone for at least 72 hours.

Brief Description Of The Drawings

The invention will be better understood from a reading of the following detailed description taken in conjunction with the drawings in which like reference designators are used to designate like elements, and in which:

FIG. 1 is a perspective view of an oil well field;

FIG. 2 illustrates a soil texture triangle used to classify the texture class of petroleum-bearing soils;

FIG. 3 is a flow chart summarizing certain steps of Applicant's method;

FIG. 4 is a flow chart summarizing certain additional steps of Applicant's method;

FIG. 5 illustrates the apparatus used to dispose or inject Applicant's treatment materials into the oil well field of FIG. 1.

Detailed Description Of The Preferred Embodiments

This invention is described in preferred embodiments in the following description with reference to the Figures, in which like numbers represent the same or similar elements. Reference throughout this specification to "one embodiment," "an embodiment," or similar language means that a particular feature, structure, or characteristic described in connection with the embodiment is included in at least one embodiment of the present invention. Thus, appearances of the phrases "in one embodiment," "in an embodiment," and similar language throughout this specification may, but do not necessarily, all refer to the same embodiment.

The described features, structures, or characteristics of the invention may be combined in any suitable manner in one or more embodiments. In the following description, numerous specific details are recited to provide a thorough understanding of embodiments of the invention. One skilled in the relevant art will recognize, however, that the invention may be practiced without one or more of the specific details, or with other methods, components, materials, and so forth. In other instances, well-known structures, materials, or operations are not shown or described in detail to avoid obscuring aspects of the invention.

The schematic flow charts included are generally set forth as logical flow chart diagrams. As such, the depicted order and labeled steps are indicative of one embodiment of the presented method. Other steps and methods may be conceived that are equivalent in function, logic, or effect to one or more steps, or portions thereof, of the illustrated method. Additionally, the format and symbols employed are provided to explain the logical steps of the method and are understood not to limit the scope of the method. Although various arrow types and line types may be employed in the flow chart diagrams, they are understood not to limit the scope of the corresponding method. Indeed, some arrows or other connectors may be used to indicate only the logical flow of the method. For instance, an arrow may indicate a waiting or monitoring period of unspecified duration between enumerated steps of the depicted method. Additionally, the order in which a particular method occurs may or may not strictly adhere to the order of the corresponding steps shown.

Referring now to FIG. 1, oil field 100 includes oil well 140. Oil well 140 is disposed in near vicinity to a plurality of oil-containing fissures 110. Oil well 140 comprises production zones 142, 144, 146, and 148.

Oil well 140 typically comprises a first tubular assembly 160 disposed within a second tubular assembly 170. The combination of tubular assemblies 160 and 170 define two separated lumens, namely lumen 165 and lumen 175. Oil is removed from fissures 110, and pumped upwardly through lumen 175.

In the illustrated embodiment of FIG. 1, blockage materials are shown blocking oil-containing fissures 110. In addition, blockage materials 130 are shown blocking portions of lumen 175. In the illustrated embodiment of FIG. 1, blockage materials 122 are disposed in production zone 142. In the illustrated embodiment of

FIG. 1, blockage materials 124 are disposed in production zone 146. In the illustrated embodiment of FIG. 1, blockage materials 126 are disposed in production zone 144. In the illustrated embodiment of FIG. 1, blockage materials 128 are disposed in production zone 148. As those skilled in the art will appreciate, each of production zones 142, 144, 146, and 148, may each comprise a plurality of blockage materials disposed in various portions of those production zones.

As a general matter, blockage materials 122, 124, 126, 128, and 130 comprise a plurality of linear, branched, and/or cyclic hydrocarbons, sometimes referred to as paraffins or waxes, in combination with one or more higher molecular, polar, aromatic molecules sometimes referred to as "asphaltenes."

Many of the paraffin compounds comprise more than 22 carbon atoms. Compounds such as botryococcane, a C₃₄ branched alkane, and β -carotene, a C₄₀ cycloalkane, have been identified in paraffin blockage materials. Moreover, deposits in pipelines can also comprise C₇₅ compounds, i.e. asphaltenes. As those skilled in the art will appreciate, asphaltenes comprise a plurality of compounds, some of which comprise fewer than 75 carbon atoms and some of which comprise more than 75 carbon atoms.

Applicant's composition and method comprises a total system treatment, which treats the source of the buildup resulting in cleaner flow lines, down hole pipes, and storage tanks. Applicant's method utilizes an environmentally friendly solvent system, in optional combination with other systems, to increase the time between treatments while maximizing production rates.

Applicant's composition, and method using that composition, re-liquefies both paraffins and asphaltenes, using, *inter alia*, high down hole pressures without utilizing known carcinogens. In addition, Applicant's method increases oil production, increases gas production, removes blockage materials for a longer period of time, removes paraffins and/or asphaltenes in the oil field formation, reduces piping corrosion rates, removes paraffins and/or asphaltenes from oil transfer lines, and reduces oil viscosity in the holding tank. United States Patent Number 7,334,641 (the '641 Patent), in the name of Castellano, is hereby incorporated herein by reference.

The '641 Patent teaches a composition and method to enhance recovery from oil wells. The composition and method of the '641 Patent may be used in

combination with the method herein, wherein the instant high pressure method is utilized 1 to 2 times per year, and wherein the method of the '641 Patent is used more routinely, for example every month.

The instant method differs from the '641 Patent in significant ways. First, the instant method includes disposing a "brine cap" into the oil well at a selected treatment pressure. Applicant's method utilizes "heavy salt water" as the brine cap. By "heavy salt water," Applicant means water that has greater than 23,000 parts per million of sodium chloride. Second, the instant method pressurizes a well that has been "brine capped" for at least 72 hours. Third, the other materials placed into the oil well prior to the brine cap and pressure are utilized at 10 times the amounts described in the '641 Patent. The cost for materials and labor associated with the '641 Patent method is about \$3,500.

The method of the '641 Patent is a replacement for routine oil well maintenance, such as hot oiling and the like. The instant method replacing much more potentially destructive prior art methods generally referring to as "Fracing." Fracing is a reference to fracturing. Using such prior art methods, an explosive charge is disposed into an oil well, and that charge is then detonated to literally fracture the subsurface soils and geology. Such a Fracing operation typically costs between \$500,000 and \$1,000,000 to perform. In addition, a Fracing operation is risky. Fracing sometimes leads to destruction of the oil field rather than generation of new oil channels in the subsurface soil structure.

Applicant's method avoids the danger and risk of explosive use. Moreover, the cost for materials and labor associated with the instant method is about \$50,000. Thus, Applicant's method described and claimed herein costs about one tenth to one twentieth the cost of Fracing without the risk of oil field destruction.

Applicant's method reduces oil viscosity while increasing the API specific gravity of the oil produced. By liquefying viscous blockage materials, Applicant's method reduces the bulk viscosity of the oil produced. In addition, by liquefying semi-solid and solid blockage materials, Applicant's method increases the API specific gravity of the oil produced.

The American Petroleum Institute index, or API specific gravity, is a measure of how heavy or light a petroleum liquid is compared to water. If its API specific gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier and sinks. API specific gravity is thus a measure of the relative density of a petroleum liquid with respect to the density of water, but it is used to compare the relative densities of petroleum liquids. For example, if one petroleum liquid floats on another and is therefore less dense, it has a greater API specific gravity. Although mathematically API specific gravity has no units (see the formula below), it is nevertheless referred to as being in “degrees”. API specific gravity is graduated in degrees on a hydrometer instrument and was designed so that most values would fall between 10 and 70 API specific gravity degrees. The formula used to obtain the API specific gravity of petroleum liquids is:

$$API\ gravity = \frac{141.5}{SG} - 131.5$$

Conversely, the specific gravity of petroleum liquids can be derived from the API specific gravity value as:

$$SG\ at\ 60^{\circ}F = \frac{141.5}{API\ gravity + 131.5}$$

Thus, a heavy oil with a specific gravity of 1.0 (i.e., with the same density as pure water at 60°F) would have an API specific gravity of:

$$\frac{141.5}{1.0} - 131.5 = 10.0^{\circ}API$$

FIGs. 3 and 4 summarize the steps of Applicant's method. Referring now to FIG. 3, in step 310 the method provides an oil well comprising a plurality of production zones, such as production zones 142, 144, 146, and 148, and a plurality of blockage materials, such as blockage materials 122, 124, 126, 128, and 130, disposed in the production zones and oil well piping.

In step 320, the method discontinues utilization of all prior art treatment methods 1-2 weeks in advance of implementing Applicant's method. By “prior art treat methods,” Applicant means discontinuing use of hot oil treatments,

benzene/toluene treatments, hot water treatments, muriatic acid treatments, and the like.

In step 330, the method cleans all flows lines, such as for example flow line 180 (FIG. 1) from the oil well to a tank battery, such as for example tank battery 190 (FIG. 1). In certain embodiments, step 330 comprises using mechanical means to remove blockages and debris from all flow lines.

In step 340, the method completes the process taught in the '641 Patent. In certain embodiments, step 340 comprises utilizing the process taught in FIGs. 2 and 3 of the '641 Patent.

In step 350, the method selects a production zone for treatment. Referring once again to FIG. 1, in certain embodiments the method in step 350 selects one production zone from production zones 142, 144, 146, and 148. In certain embodiments, in step 350 the method selects all production zones disposed at about the same depth in the well. For example in the illustrated embodiment of FIG. 1, in step 350 the method selects production zones 142 and 146 for treatment.

In step 350, the method further isolates the selected production zone(s) from the remaining production zones disposed in the oil well of step 310. In certain embodiments, step 350 comprises installing a down hole tool into an oil well comprising more than one set of perforations located at differing depths, such that all injected materials are squeezed at high pressure into only the selected production zone(s).

In step 360, the method selects a treatment pressure for the selected production zone(s). In certain embodiments, the method in step 360 selects a treatment pressure based upon soil texture and porosity in the selected production zone(s), down hole pressure in the selected production zone(s), and maximum lateral dimension of the selected production zone(s).

For example and referring once again to FIG. 1, production zones 142 and 144 comprise a maximum lateral dimension 143. Production zones 146 and 148 comprise a maximum lateral dimension 147. As the lateral dimension of a selected production zone increases, the operating pressure must be set higher. Applicant has found, however, that as a maximum lateral dimension increases by a factor of (N), the operating pressure must increase by a factor (x) times (N). In certain embodiments,

(x) is 2. In certain embodiments, (x) is 4. In certain embodiments, (x) is greater than 4.

In certain embodiments, in step 360 the method selects an operating pressure using an effective porosity determined for the selected production zone(s). The operating pressure selected in step 360 is inversely proportional to the effective porosity of selected production zone(s). Applicant has found, however, that as an effective porosity for the selected production zone decreases by a factor of (N), the operating pressure must increase by a factor (y) times (N). In certain embodiments, (y) is 2. In certain embodiments, (y) is 4. In certain embodiments, (y) is greater than 4.

Soil texture refers to the relative proportion of sand, silt and clay size particles in a sample of soil. Clay size particles are the smallest being less than .002 mm in size. Silt is a medium size particle falling between 0.002 and 0.05 mm in size. The largest particle is sand with diameters between 0.05 for fine sand to 2.0 mm for very coarse sand. Soils that are dominated by clay are called fine textured soils while those dominated by larger particles are referred to as coarse textured soils. Soil textures can be divided into soil texture classes. Referring now to FIG. 2, soil texture triangle 200 is used to classify the texture class of petroleum-bearing soils.

Soil texture controls many other properties like structure, chemistry, porosity, and permeability. Porosity of a soil is the volume of all the open spaces (pores) between the solid grains of soil. Soil permeability is the property of the soil pore system that allows fluid to flow therethrough. Generally, pore sizes and their connectivity determine whether a soil has high or low permeability. Fluids will flow more readily through soil with large pores with good interconnectivity between those pores. Smaller pores with the same degree of connectivity have lower permeability. Coarse textured soils tend to have large, well-connected pore spaces and hence high permeability.

Soil structure is the way soil particles aggregate together into what are called peds. Peds come in a variety of shapes depending on the texture, composition, and environment.

Granular, or crumb structures, look like cookie crumbs. They tend to form an open structure that allows fluids to penetrate the soil. Platy structure looks like stacks

of dinner plates overlaying one another. Platy structure tends to impede the downward movement of fluids. Bulk density of a soil is calculated as the mass per unit volume including the pore space. Bulk density increases with clay content and is considered a measure of the compactness of the soil. The greater the bulk density, the more compact the soil. Compact soils have low permeability.

The total porosity of a porous medium is the ratio of the pore volume to the total volume of a representative sample of the medium. Assuming that the soil system is composed of three phases -- solid, liquid (water), and gas (air) -- where V_s is the volume of the solid phase, V_l is the volume of the liquid phase, V_g is the volume of the gaseous phase, $V_p = V_l + V_g$ is the volume of the pores, and $V_t = V_s + V_l + V_g$ is the total volume of the sample, then the total porosity of the soil sample, p_t , is defined as follows:

$$p_t = \frac{V_p}{V_t} = \frac{V_l + V_g}{V_s + V_l + V_g} \quad (3.1)$$

Porosity is a dimensionless quantity and can be reported either as a decimal fraction or as a percentage. Table 1 lists representative total porosity ranges for various geologic materials. A more detailed list of representative porosity values (total and effective porosities) is provided in Table 2. In general, total porosity values for unconsolidated materials lie in the range of 0.25-0.7 (25%-70%). Coarse-textured soil materials such as gravel and sand tend to have a lower total porosity than fine-textured soils such as silts and clays. The total porosity in soils is not a constant quantity because the soil, particularly clayey soil, alternately swells, shrinks, compacts, and cracks.

TABLE 1 Range of Porosity Values

Soil Type	Porosity, p_t
Unconsolidated deposits	
Gravel	0.25 - 0.40
Sand	0.25 - 0.50
Silt	0.35 - 0.50
Clay	0.40 - 0.70
Rocks	
Fractured basalt	0.05 - 0.50
Karst limestone	0.05 - 0.50
Sandstone	0.05 - 0.30
Limestone, dolomite	0.00 - 0.20
Shale	0.00 - 0.10
Fractured crystalline rock	0.00 - 0.10
Dense crystalline rock	0.00 - 0.05
Source: Freeze and Cherry (1979).	

TABLE 2 Representative Porosity Values

Material	Total Porosity, p_t		Effective Porosity, p_e	
	Range	Arithmetic Mean	Range	Arithmetic Mean
Sedimentary material				
Sandstone (fine)	- ^b	-	0.02 - 0.40	0.21
Sandstone (medium)	0.14 - 0.49	0.34	0.12 - 0.41	0.27
Siltstone	0.21 - 0.41	0.35	0.01 - 0.33	0.12
Sand (fine)	0.25 - 0.53	0.43	0.01 - 0.46	0.33
Sand (medium)	-	-	0.16 - 0.46	0.32
Sand (coarse)	0.31 - 0.46	0.39	0.18 - 0.43	0.30
Gravel (fine)	0.25 - 0.38	0.34	0.13 - 0.40	0.28
Gravel (medium)	-	-	0.17 - 0.44	0.24
Gravel (coarse)	0.24 - 0.36	0.28	0.13 - 0.25	0.21
Silt	0.34 - 0.51	0.45	0.01 - 0.39	0.20
Clay	0.34 - 0.57	0.42	0.01 - 0.18	0.06
Limestone	0.07 - 0.56	0.30	~0 - 0.36	0.14
Wind-laid material				
Loess	-	-	0.14 - 0.22	0.18
Eolian sand	-	-	0.32 - 0.47	0.38
Tuff	-	-	0.02 - 0.47	0.21
Igneous rock				
Weathered granite	0.34 - 0.57	0.45	-	-
Weathered gabbro	0.42 - 0.45	0.43	-	-
Basalt	0.03 - 0.35	0.17	-	-
Metamorphic rock				
Schist	0.04 - 0.49	0.38	0.22 - 0.33	0.26

As those skilled in the art will appreciate, the effective porosity, p_e , also called the kinematic porosity, of a porous medium is defined as the ratio of the part of the pore volume where the fluid can circulate to the total volume of a representative sample of the medium. In naturally porous systems such as subsurface soil, where the flow of fluid is caused by the composition of capillary, molecular, and gravitational forces, the effective porosity can be approximated by the specific yield, or drainage porosity, which is defined as the ratio of the volume of fluid drained by gravity from a saturated representative sample of the soil to the total volume of the sample.

The definition of effective (kinematic) porosity is linked to the concept of pore fluid displacement rather than to the percentage of the volume occupied by the pore spaces. The pore volume occupied by the pore fluid that can circulate through the porous medium is smaller than the total pore space, and, consequently, the effective porosity is always smaller than the total porosity. In a saturated soil system composed of two phases (solid and liquid) where (1) V_s is the volume of the solid phase, (2) $V_w = (V_{iw} + V_{mw})$ is the volume of the liquid phase, (3) V_{iw} is the volume of immobile pores containing the fluid adsorbed onto the soil particle surfaces and the fluid in the dead-end pores, (4) V_{mw} is the volume of the mobile pores containing fluid that is free to move through the saturated system, and (5) $V_t = (V_s + V_{iw} + V_{mw})$ is the total volume, the effective porosity can be defined as follows:

$$p_e = \frac{V_{mw}}{V_t} = \frac{V_{mw}}{V_s + V_{mw} + V_{iw}} \quad (4.1)$$

Another soil parameter related to the effective soil porosity is the field capacity, θ_r , also called specific retention, irreducible volumetric fluid content, or residual fluid content, which is defined as the ratio of the volume of fluid retained in the soil sample, after all downward gravity drainage has ceased, to the total volume of the sample. Considering the terms presented above for a saturated soil system, the total porosity p_t and the field capacity θ_r can be expressed, respectively, as follows:

$$p_t = \frac{V_{mw} + V_{iw}}{V_t} \quad (4.2)$$

and

$$\theta_r = \frac{V_{iw}}{V_t} \quad (4.3)$$

Therefore, the effective porosity is related to the total porosity and the field capacity according to the following expression:

$$p_e = p_t - \theta_r \quad (4.4)$$

Several aspects of the soil system influence the value of its effective porosity:

(1) the adhesive fluid on minerals, (2) the absorbed fluid in the clay-mineral lattice, (3) the existence of unconnected pores, and (4) the existence of dead-end pores. The adhesive fluid in the soil is that part of the fluid present in the soil that is attached to the surface of the soil grains through the forces of molecular attraction. The sum of the volumes of the adhesive and absorbed fluid plus the fluid that fills the unconnected and dead-end pores constitute the volume of the adsorbed fluid, V_{iw} , that is unable to move through the system.

Determination of the effective porosity, p_e , of soils can be accomplished indirectly by measuring the total porosity, p_t , and the field capacity, θ_r , and then calculating p_e . The total porosity is obtained indirectly by measuring the soil densities. To determine the field capacity of the soils, the soil sample is first saturated with fluid and is then allowed to drain completely under the action of gravity until it gets to its irreducible saturation. The value of θ_r can then be obtained according to the methods used for measuring volumetric fluid content.

Referring once again to FIG. 3, in step 370 the method discontinues use of the well pump, and reconfigures one or more flow lines to allow direct injection of treatment materials under pressure into the selected production zone(s). In certain embodiments, the method in step 370 places the oil well of step 310 into a configuration illustrated in FIG. 5. In the illustrated embodiment of FIG. 5, treatment materials are disposed in vessel 510, and those treatment materials are injected into the selected production zone(s) using pump 520, piping 530, and optionally a down hole tool that allows treatment materials under pressure to be squeezed into the selected production zone(s) while isolating all non-selected production zones.

The method transitions from step 370 to step 410 (FIG. 4) wherein the method prepares a bacteria system. Applicant's bacteria system comprises paraffin-digesting bacteria. Applicant's bio system comprises a dry powder which is re-circulated and grown in an oxygenated water comprising 2-3 ppm oxygen for 24 hours while being fed a combination of organic nutrients, which enable a large colony count of bacteria (10^8 to 10^9 Colony Forming Units ("CFU") per milliliter). Every 3 pounds of bacteria culture is combined with 5 gallons of bio-nutrient in 300 gallons of non-chlorinated, oxygenated water. In certain embodiments, Applicant's bio system comprises *Arthrobacter globiformis*, *Arthrobacter citreus*, *Nitrosomonas*, *Nitrobacter*, *Bacillus licheniformis*, *Bacillus amyloliquefaciens*, *Bacillus subtilis*, *Bacillus megaterium*, and *Bacillus pumilus*. *Arthrobacters* comprise gram positive, aerobic rods that constitute a large portion of the aerobic chemoheterotrophic population of soil bacteria. In certain embodiments, Applicant's bio system further comprises sea weed cream, Leonardite extract, fish parts, and combinations thereof.

In step 420, the method injects 20 to 50 cubic meters of brine solution into the selected production zone(s). In step 430, the method pressurizes the selected production zone(s) to the treatment pressure of step 360.

In step 440, the method injects a solvent system under pressure into the selected production zone while maintaining the treatment pressure of step 360. In certain embodiments, the solvent system of step 440 comprises between 34-46 volume percent of a hydrogenated, light petroleum distillate. In certain embodiments, Applicant's light petroleum distillate comprises a mixture of hydrocarbon compounds, wherein that mixture is assigned Chemical Abstracts System ("CAS") Number 64742-47-8. Applicant's light petroleum distillate comprises a product sold in commerce under the tradename Drakesol 165. In certain embodiments, Applicant's light petroleum distillate comprises a product sold in commerce under the tradename Drakesol 2251. In certain embodiments, Applicant's light petroleum distillate comprises deodorized kerosene.

In certain embodiments, the solvent system of step 440 further comprises about 34 volume percent of a hydrogenated, medium petroleum distillate. In certain embodiments, Applicant's medium petroleum distillate comprises a mixture of hydrocarbon compounds, where that mixture is assigned CAS No. 64742-46-7. In

certain embodiments, Applicant's medium petroleum distillate comprises a product sold in commerce under the tradename Drakesol 205. In certain embodiments, Applicant's first hydrocarbon solvent comprises a product sold in commerce under the tradename Drakesol 2257.

In certain embodiments, the solvent system of step 440 further comprises between about 20 to about 32 volume percent of one or more terpenoid compounds. By "terpenoid compound," Applicant means a hydrocarbon compound comprising between about 10 carbon atoms and about 15 carbon atoms, and further comprising an alkenyl moiety, and/or a cyclohexane moiety, and/or a cyclohexene moiety. For example, in certain embodiments, Applicant's one or more terpenoid compounds comprise one or more of .beta.-pinene, menthene, p-menthane, limonene, alpha.-pinene, citrene, carvene and mixtures thereof.

In certain embodiments, step 440 comprises injecting at least about 550 gallons of Applicant's solvent system into the selected production zone(s). In certain embodiments, step 440 comprises injecting 1110 gallons of Applicant's solvent system into the selected production zone(s).

In step 450, the method injects under pressure Applicant's salt extraction system while maintaining the treatment pressure of step 360. In certain embodiments, Applicant's salt extraction system comprises a mixture of humic acid and fulvic acid. In certain embodiments, Applicant's humic/fulvic acid mixture comprises a weight ratio from about 95:5 humic acid/fulvic acid to about 5:95 humic acid/fulvic acid. In certain embodiments, Applicant's method utilizes a 50/50 mixture by weight a humic acid/fulvic acid mixture disposed in phosphoric acid. In certain embodiments, Applicant's mixture of humic acid and fulvic acid are mixed in a formation further comprising Urea, Potassium Hydroxide, mild Phosphoric Acid, mixtures thereof, and the like.

Humic acid comprises acidic materials extracted from Leonardite, where those acidic extracts are soluble in alkali, but insoluble in acid, methyl ethyl ketone, and methyl alcohol. Fulvic acid comprises acidic materials extracted from Leonardite, where those acidic extracts are soluble in alkali, acid, methyl ethyl ketone, and methyl alcohol. As those skilled in the art will appreciate, Leonardite comprises a soft, brown coal-like deposit found in conjunction with deposits of lignite.

In certain embodiments, Applicant's salt extraction system comprises selected amounts of Humic acid, Fulvic acid, Urea, Potassium Hydroxide, and mild Phosphoric Acid, mixed with water. The amount of salt extraction system injected is determined by the mineral content of the oil-bearing formation. In certain embodiments, step 450 comprises injecting at least about 110 gallons of Applicant's salt extraction system into the selected production zone(s). In certain embodiments, step 450 comprises injecting 275 gallons of Applicant's salt extraction system into the selected production zone(s).

In step 460, the method injects under pressure Applicant's bacteria system of step 410 into the selected production zone(s) while maintaining the treatment pressure of step 360. In certain embodiments, step 450 comprises injecting at least about 9,000 gallons of Applicant's bacteria system into the selected production zone(s). In certain embodiments, step 450 comprises injecting 12,000 gallons of Applicant's bacteria system into the selected production zones(s).

In step 470, the method injects about 40 to about 50 cubic meters of brine solution under pressure into the selected production zone(s) while maintaining the treatment pressure of step 360. In step 480, the method maintains the treatment pressure for at least, and in certain embodiments more than, 72 hours. During this "soak" period, Applicant's bacteria system begins to liquefy heavy crude portion of the petroleum disposed in the selected production zone(s). Further, during this "soak" period Applicant's salt extractor system opens flow channels in the petroleum-bearing foundation, thereby increasing the effective porosity of that foundation. In certain embodiments, the oil well is not re-circulated during this "soak" period.

In step 490, the method reconfigures the oil well for production, and returns the oil well to service.

The following examples are presented to further illustrate to persons skilled in the art how to make and use the invention. These examples are not intended as a limitation, however, upon the scope of the invention.

EXAMPLE I

A Canadian oil company operates a series of medium sized oil fields pumping on shore oil in or near Lethbridge Canada. This field, in some areas, has been

producing since 1949. Applicant performed a field trial using Applicant's method to determine if an increase in production rates in a heavily water pressurized field could be realized. Well number 8-2-48-24w3, which comprises a heavily paraffinated well, was utilized for this field trial. This field trial realized an increase of pump efficiency of 13% with an average production increase of 220%.

According to step 360, a treatment pressure of 1000 psi was selected for this field trial. Because Well number 8-2-48-24w3 comprises a heavily water pressurized well, no brine solution was utilized in step 420 of Applicant's method. In step 430, an operating pressure of 1000 psi was set and maintained in a flow line to Well number 8-2-48-24w3.

According to step 440, about 550 gallons of solvent system were injected into Well number 8-2-48-24w3 a calculated 50 meters into the formation, while maintaining the operating pressure of 1000 psi in the flow line. According to step 450, 55 gallons of salt extractor system were injected into Well number 8-2-48-24w3 a calculated 50 meters into the formation, while maintaining the operating pressure of 1000 psi in the flow line. According to step 460, 9000 gallons of bacteria system were injected into Well number 8-2-48-24w3 a calculated 50 meters into the formation, while maintaining the operating pressure of 1000 psi in the flow line.

<u>Well Number</u>	<u>Date</u>	<u>Location</u>	<u>Hole Diameter</u>	<u>Hole Depth</u>
8-2-48-24w3	January 2009	SAHA Wells	44 cm	2500 meter

Baseline

<u>Date</u>	<u>Daily Liquid</u>	<u>Oil</u>	<u>Water Percent</u>	<u>Gas</u>
Daily	22.25 m ³	1.935 m ³ /day	92%	0m ³
Jan 2009	687 m ³ /Month	60 m ³ /Month	91%	0m ³ /Month

*1m³ = 6.3 Barrels

<u>March (18-24)</u>	<u>Liquid/Week</u>	<u>Oil/Week</u>	<u>Water Percent</u>	<u>Gas/Week</u>
Add on 18th	484m ³	42m ³	90%	0m ³
Delta Δ	311%*	307%*	↓ 1%	0%

<u>March (25-31)</u>	<u>Liquid/Week</u>	<u>Oil/Week</u>	<u>Water Percent</u>	<u>Gas/Week</u>
	467m ³	41 m ³	90%	0m ³
Delta Δ	↑300 %	↑300 %	↓ 1%	↑ 0%

<u>April (1-7)</u>	<u>Liquid/Week</u>	<u>Oil/Week</u>	<u>Water Percent</u>	<u>Gas/Week</u>
	327m ³	30 m ³	90%	0m ³
Delta Δ	↑ 210%	↑ 220%	↓ 1%	↑ 0%

<u>April (8-14)</u>	<u>Liquid/Week</u>	<u>Oil/Week</u>	<u>Water Percent</u>	<u>Gas/Week</u>
	342m ³	30m ³	91%	0m ³
Delta Δ	↑220 %	↑220 %	↓ 0%	0%

The first month returns indicate an average monthly increase in oil production of 261%, or a daily increase of 20 BOPD and a monthly increase of over 600 Barrels of oil in a 1 month period. Significantly, the percent of water pumped decreased while the percentage of oil pumped increased.

EXAMPLE II

The Da Qing oil fields (a part of China Oil) is the biggest on shore oil field in the nation of China with over 50,000 producing wells. This field, in some areas, has been producing since 1959 and has produced one million barrels of oil per day.

The Da Qing field monthly performed the well clean-up procedures for heavy paraffin taught in the '641 Patent, and typically realized an increase of pump efficiency of 17% with an average production increase of 22%.

Applicant's instant method was utilized as a field test using Well number GOGD18-20 to determine if a yearly application of the instant high pressure method can augment monthly use of the method of the '641 Patent.

According to step 360, a treatment pressure of 800 psi was selected for this field trial. In step 430, an operating pressure of 800 psi was set and maintained in a flow line to Well GOGD18-20.

According to step 440, about 110 gallons of solvent system were injected into Well number GOGD18-20 a calculated 50 meters into the formation, while maintaining the operating pressure of 800 psi in the flow line. Applicant's high

pressure method would usually utilize about four (4) times this amount of solvent system. However, a lesser amount was used in this field trial.

According to step 450, 55 gallons of salt extractor system were injected into Well GOGD18-20 a calculated 50 meters into the formation, while maintaining the operating pressure of 800 psi in the flow line. Applicant's high pressure method would usually utilize about two (2) times this amount of salt extractor system.

However, a lesser amount was used in this field trial.

According to step 460, 8000 gallons of bacteria system were injected into Well GOGD18-20 a calculated 50 meters into the formation, while maintaining the operating pressure of 800 psi in the flow line.

Da Qing Data

<u>Well Number</u>	<u>Date</u>	<u>Location</u>	<u>Hole Diameter</u>	<u>Hole Depth</u>
GOGD 18-20	January 20, 2006	S31-32	44 cm	2404 meters

Baseline

<u>Date</u>	<u>Daily Liquid</u>	<u>Oil</u>	<u>Water Percent</u>	<u>Gas</u>
January 20, 2006	1.9 Tons	1 Ton	92%	2.3m ³
	57 Tons/Month	30 Tons/Month	92%	69m ³ /Month

*1TON = 7.4 Barrels

<u>January</u>	<u>Liquid/Month</u>	<u>Oil/Month</u>	<u>Water Percent</u>	<u>Gas/Month</u>
	42 Tons	21.8 Tons	91%	75.4m ³
Delta Δ	↓ 26%	↓ 27%	↓ 1%	↑ 9.3%

<u>February</u>	<u>Liquid/Month</u>	<u>Oil/Month</u>	<u>Water Percent</u>	<u>Gas/Month</u>
	88.45 Tons	48.6 Tons	82%	77.5m ³
Delta Δ	↑ 55%	↑ 62%	↓ 10%	↑ 12%

<u>March</u>	<u>Liquid/Month</u>	<u>Oil/Month</u>	<u>Water Percent</u>	<u>Gas/Month</u>
	220.8 Tons	124 Tons	78%	119.7m ³
Delta Δ	↑ 387%	↑ 413%	↓ 14%	↑ 73%

<u>April</u>	<u>Liquid/Month</u>	<u>Oil/Month</u>	<u>Water Percent</u>	<u>Gas/Month</u>
	244.6 Tons	143.9 Tons	70%	111m ³
Delta Δ	↑ 429%	↑ 479%	↓ 22%	↑ 60%

<u>May 1-8</u>	<u>Liquid/Month</u>	<u>Oil/Month</u>	<u>Water Percent</u>	<u>Gas/Month</u>
	64.5 Tons	39.1 Tons	65%	29.6m ³
Delta Δ	↓ 424%	↑ 261%	↓ 27%	↑ 161%

The first month returns showed modest increases due to utilization of lesser amount of solvent system and salt extractor system. Overall however, an excellent increase in production was realized. Once again, the percent of water pumped decreased while the percentage of oil pumped increased.

Examples I and II demonstrate the utility of Applicant's method to increase both the amount of oil produced, and the percentage of oil produced, from existing, heavily water pressurized, oil wells. In addition, Applicant's method decreases the percentage of water produced from such heavily water pressurized oil, existing oil wells.

Prior art treatment methods do not increase the Oil Cut Percentage from a well. Rather, those prior art methods may increase a daily production of total fluids from a well thereby realizing an increased oil production. In marked distinction, Applicant's method results in BOTH an increased Oil Cut Percentage and an increased Oil Production.

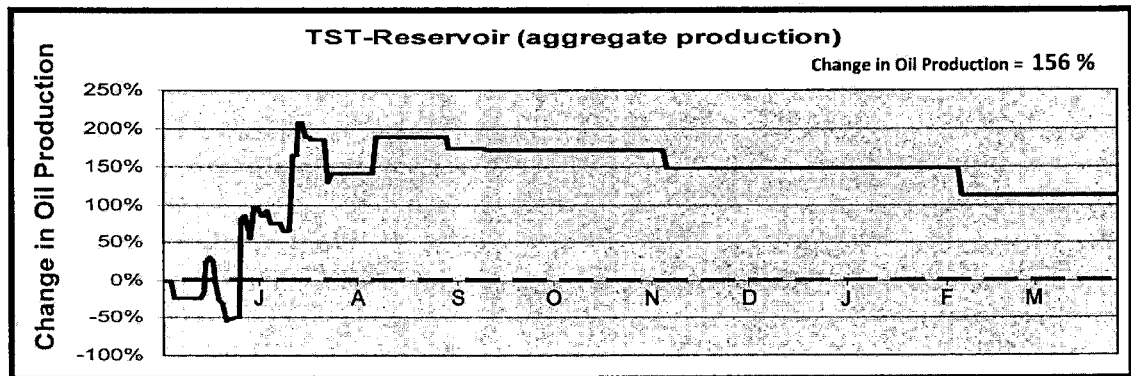
EXAMPLE III

A. OVERVIEW

Four different wells in a Canadian Diamond Creek oil field were treated with Applicant's method. Wells 11-16, 15-10, 12-10, and 2-16, were selected. These four wells were selected because they each comprise different characteristics. The differing characteristics include depth of well, production rates, down hole temperature and pressure, oil to water ratio, production rate, and water quality and characteristics.

In each of the four wells selected, a brine cap of 40 cubic meters was utilized. Chart 1 summarizes the aggregate change in oil production from all four wells from early June 2009 through the end of March 2010. Treatment of Wells 11-16, 15-10, 12-10, and 2-16, realized an overall oil production average increase of 156 percent.

CHART 1



B. Well 11-16

The baseline production for Well 11-16 was an oil cut of 4.5% and a total fluid flow of 22 m³. Charts 2 and 3 summarize the oil production for Well 11-16 prior to treatment, during treatment, and after treatment.

Prior to treatment, Well 11-16 produced 22 m³ of fluid daily, with an oil cut of about 10.8%. This translates into a daily production of about 1.0 cubic meters of oil per day.

CHART 2

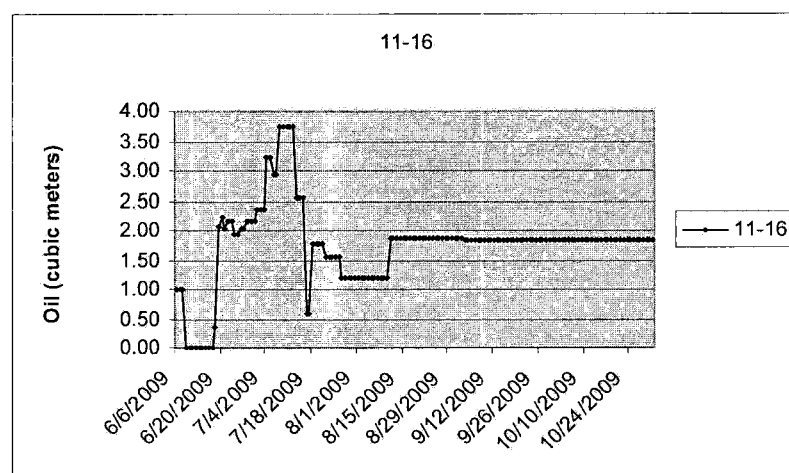
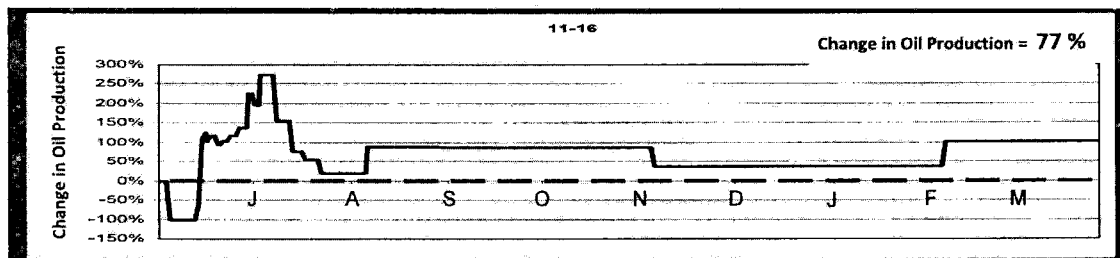


CHART 3



Well 11-16 was taken out of service, and remained under pressure per Applicant's method for 72 hours. Production was resumed on or about June 20, 2009. A surge in oil production was seen from about June 20, 2009 through about July 18, 2009. This "surge" resulted from release of the bring cap after the pressure was released from Well 11-16 at the end of treatment. This surge of aqueous fluids translated into a corresponding surge of oil production. Thereafter, Well 11-16 reached an equilibrium level of total fluid production of about 18 m³ daily with an oil cut of about 10.8%. Well 11-16 realized a 240% increase in Oil Cut from use of Applicant's method.

C. WELL 15-10

The baseline production for Well 15-10 was an oil cut of 1.8% and a total fluid flow of 69 m³. Charts 4 and 5 summarizes the oil production for Well 15-10 prior to treatment, during treatment, and after treatment.

Prior to treatment, Well 15-10 produced 69 m³ of fluid daily, with an oil cut of about 1.8%. This translates into a daily production of about 1.2 cubic meters of oil per day.

CHART 4

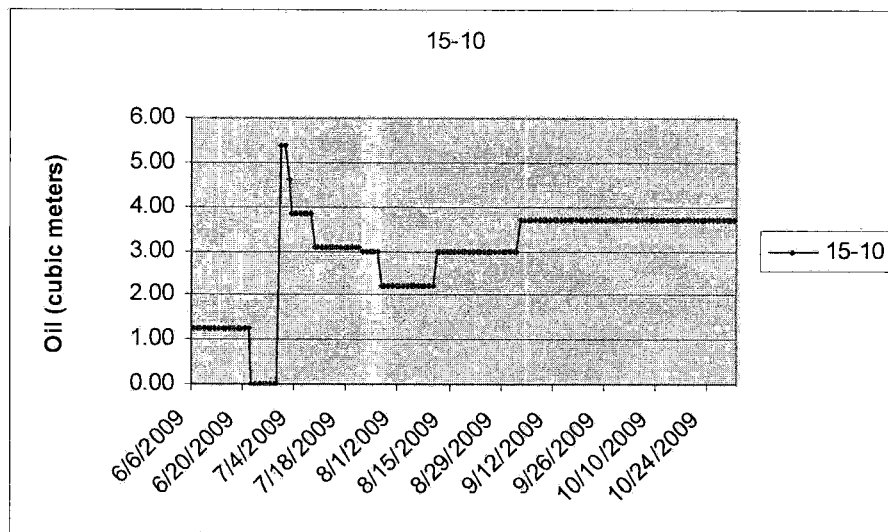
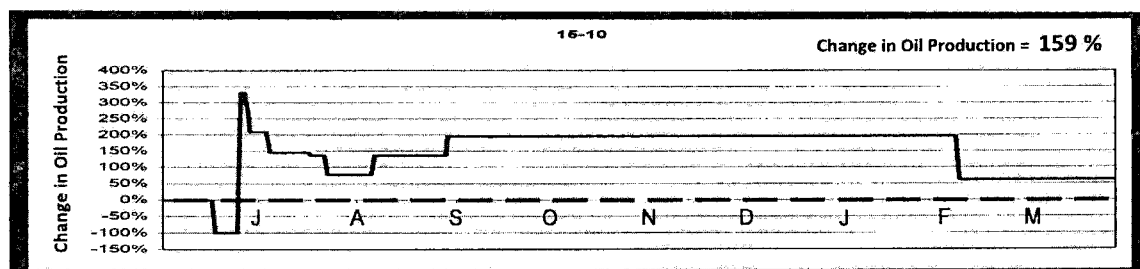


CHART 5



Well 15-10 was taken out of service, and remained under pressure per Applicant's method for 72 hours. Production was resumed on or about July 4, 2009. A surge in oil production was seen from about July 4, 2009 and continued for about a week. This "surge" resulted from release of the bring cap after the pressure was released from Well 15-10 at the end of treatment. This surge of aqueous fluids translated into a corresponding surge of oil production. Thereafter, Well 15-10 reached an equilibrium level of total fluid production of about 84 m³ daily with an oil cut of about 4.0% Well 15-10 realized a 220% increase in Oil Cut from use of Applicant's method.

D. WELL 12-10

The baseline production for Well 12-10 was an oil cut of 8.9% and a total fluid flow of 11 m³. Charts 6 and 7 summarizes the oil production for Well 12-10 prior to treatment, during treatment, and after treatment.

Prior to treatment, Well 12-10 produced 11 m³ of fluid daily, with an oil cut of about 8.9%. This translates into a daily production of about 1.0 cubic meters of oil per day.

CHART 6

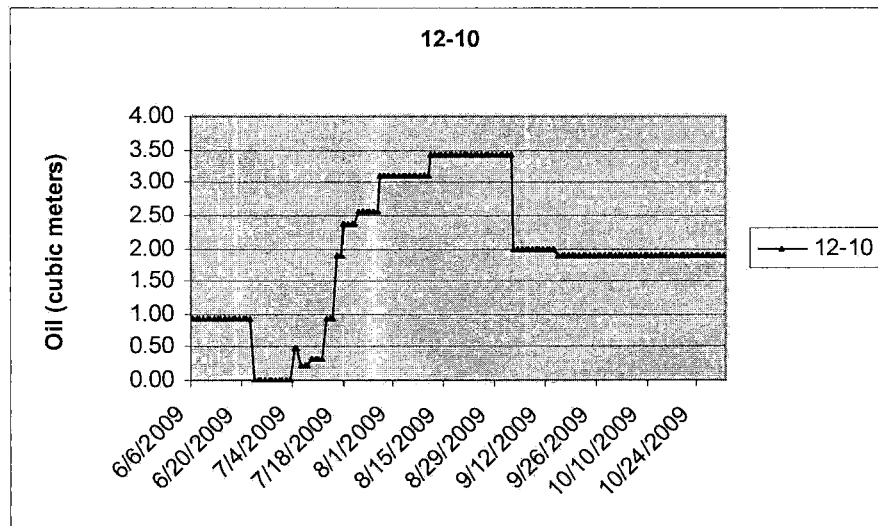
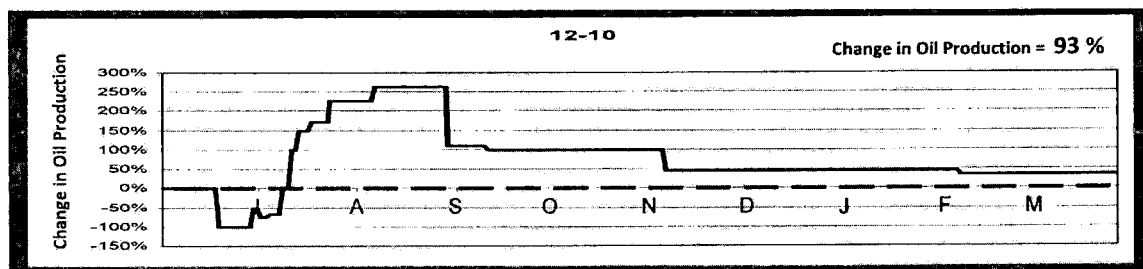


CHART 7



Well 12-10 was taken out of service, and remained under pressure per Applicant's method for 72 hours. Production was resumed on or about July 18, 2009. A surge in oil production was seen from about July 18, 2009 through about September 12, 2009. This "surge" resulted from release of the bring cap after the pressure was released from Well 12-10 at the end of treatment. This surge of aqueous fluids translated into a corresponding surge of oil production. Thereafter, Well 12-10

reached an equilibrium level of total fluid production of about 14 m³ daily with an oil cut of about 18.2%. Well 11-16 realized a 204% increase in Oil Cut, and an increase of about 161% in Oil Production, from use of Applicant's method.

E. WELL 2-16

The baseline production for Well 2-16 was an oil cut of 12.7% and a daily total fluid flow of 8 m³. Charts 8 and 9 summarizes the oil production for Well 2-16 prior to treatment, during treatment, and after treatment.

Prior to treatment, Well 2-16 produced 8 m³ of fluid daily, with an oil cut of about 12.7%. This translates into a daily production of about 0.13 cubic meters of oil per day.

CHART 8

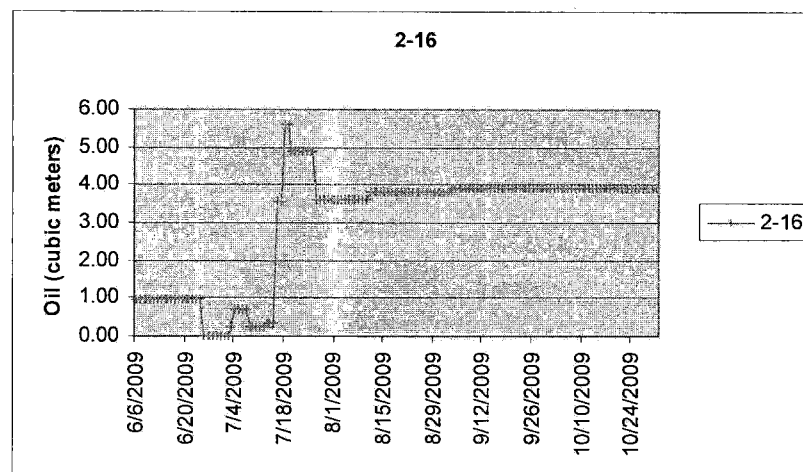
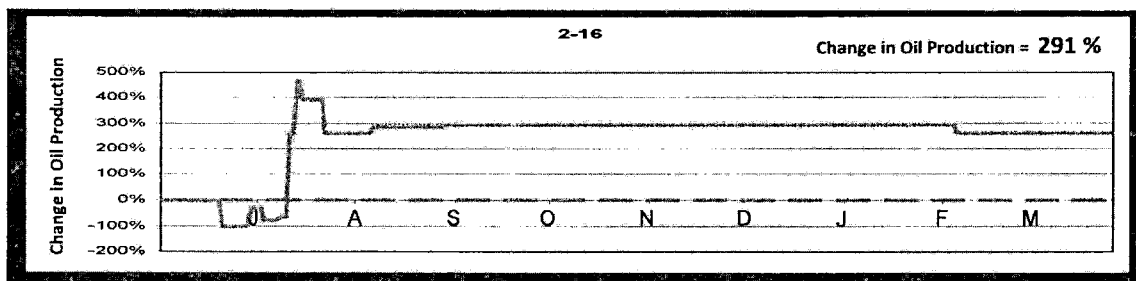


CHART 9



Well 2-16 was taken out of service, and remained under pressure per Applicant's method for about 10 days. Production was resumed on or about July 18, 2009. A surge in oil production was seen from about July 18, 2009 through about August 1, 2009. This "surge" resulted from release of the bring cap after the pressure

was released from Well 2-16 at the end of treatment. This surge of aqueous fluids translated into a corresponding surge of oil production. Thereafter, Well 2-16 reached an equilibrium level of total fluid production of about 10 m³ daily with an oil cut of about 40.5%. Well 2-16 realized a 320% increase in Oil Cut, and a 301% increase in Oil Production, from use of Applicant's method.

While the preferred embodiments of the present invention have been illustrated in detail, it should be apparent that modifications and adaptations to those embodiments may occur to one skilled in the art without departing from the scope of the present invention as set forth in the following claims

I claim:

1. A method to increase oil production from an oil well comprising a plurality of production zones, comprising:
 - selecting a production zone;
 - isolating said selected production zone;
 - reconfiguring flow lines to allow direct injection of materials under pressure into said selected production zone;
 - determining a treatment pressure based upon soil porosity in said selected production zone;
 - injecting a brine solution into said selected production zone at said selected pressure;
 - maintaining said selected pressure in said selected production zone for at least 72 hours.
2. The method of claim 1, wherein said determining further comprises calculating a kinematic porosity of soils disposed in said selected production zone.
3. The method of claim 2, wherein said calculating further comprises:
 - measuring a soil density of said soils disposed in said selected production zone;
 - determining a field capacity of said soils disposed in said selected production zone; and
 - setting said kinematic porosity equal to said soil density minus said field capacity.
4. The method of claim 1, wherein said injecting further comprises injecting at least 20 cubic meters of said brine solution.
5. The method of claim 4, wherein said injecting further comprises preparing a brine solution comprising at least 23,000 ppm sodium chloride.
6. The method of claim 1, further comprising injecting into said selected production zone at said selected pressure at least 550 gallons of a solvent system comprising a mixture of petroleum distillates, wherein said solvent system is injected into said selected production zone prior to injection of said brine solution.
7. The method of claim 6, further comprising injecting into said selected production zone at said selected pressure a mixture of humic acid and fulvic acid in

phosphoric acid after injecting said solvent system but prior to injecting said brine solution.

8. The method of claim 7, further comprising injecting at least 110 gallons of said humic acid / fulvic acid mixture into said selected production zone at said selected pressure.

9. The method of claim 8, further comprising:
growing a bacteria culture comprising paraffin-digesting bacteria, wherein said bacteria culture comprises at least 10^8 Colony Forming Units per milliliter;
forming an aqueous bacteria system comprising said bacteria culture at a level of one pound of bacteria culture in 100 gallons of non-chlorinated water;
injecting into said selected production zone at said selected pressure said aqueous bacteria system after injecting said humic acid / fulvic acid mixture but prior to injection of said brine solution.

10. The method of claim 9, further comprising injecting at least 9,000 gallons of said bacteria system.

11. A method to increase an oil cut percentage produced from an oil well comprising a plurality of production zones, comprising:
selecting a production zone;
isolating said selected production zone;
reconfiguring flow lines to allow direct injection of materials under pressure into said selected production zone;
determining a treatment pressure based upon soil porosity in said selected production zone;
injecting a brine solution into said selected production zone at said selected pressure;
maintaining said selected pressure in said selected production zone for at least 72 hours.

12. The method of claim 11, wherein said determining further comprises calculating a kinematic porosity of soils disposed in said selected production zone.

13. The method of claim 12, wherein said calculating further comprises:

measuring a soil density of said soils disposed in said selected production zone;

determining a field capacity of said soils disposed in said selected production zone; and

setting said kinematic porosity equal to said soil density minus said field capacity.

14. The method of claim 11, wherein said injecting further comprises injecting at least 20 cubic meters of said brine solution.

15. The method of claim 14, wherein said injecting further comprises preparing a brine solution comprising at least 23,000 ppm sodium chloride.

16. The method of claim 11, further comprising injecting into said selected production zone at said selected pressure at least 550 gallons of a solvent system comprising a mixture of petroleum distillates, wherein said solvent system is injected into said selected production zone prior to injection of said brine solution.

17. The method of claim 16, further comprising injecting into said selected production zone at said selected pressure a mixture of humic acid and fulvic acid in phosphoric acid after injecting said solvent system but prior to injecting said brine solution.

18. The method of claim 17, further comprising injecting at least 110 gallons of said hum acid / fulvic acid mixture into said selected production zone at said selected pressure.

19. The method of claim 18, further comprising:
growing a bacteria culture comprising paraffin-digesting bacteria, wherein said bacteria culture comprises at least 10^8 Colony Forming Units per milliliter;
forming an aqueous bacteria system comprising said bacteria culture at a level of one pound of bacteria culture in 100 gallons of non-chlorinated water;
injecting into said selected production zone at said selected pressure said aqueous bacteria system after injecting said humic acid / fulvic acid mixture but prior to injection of said brine solution.

20. The method of claim 19, further comprising injecting at least 9,000 gallons of said bacteria system.