FIG. 1.

FIG. 2.
WELL TREATING METHOD USING RELATIVELY HIGH FLUID LOSS TREATING LIQUIDS

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ABSTRACT OF THE DISCLOSURE

A method of treating wells for providing a continuing or prolonged treatment of a desired type by introducing into a producing formation a thin, high fluid loss treating liquid under a pressure sufficiently great to cause the treating liquid to be substantially lost to a fracture face near the well bore. The treating liquid is subsequently slowly produced back with the well fluids.

This application is a continuation-in-part of application Ser. No. 278,327 filed Mar. 6, 1963, now abandoned, and is entitled to all the benefits provided by law of said earlier filed application.

The present invention relates to a new and improved method of treating wells and more especially to a method wherein a relatively high fluid loss treating liquid of a desired type is placed in a producing formation and slowly produced back with the produced fluids.

In modern oil and gas well treating practices, it has become very important to provide prolonged benefits from single treatments for wells, whether such treatments be for paraffin control, scale control, corrosion control or other. One way in which paraffin inhibition and control is provided over a period of time is illustrated in U.S. Patent No. 3,051,653. In such well treatment method, certain slowly soluble paraffin inhibiting solid chemicals are placed in the well or back in the formation, and as the well fluids are produced, they are treated with the chemicals. The treatments have proved to be very satisfactory, but solubility rates and melting points may be coordinated with well conditions to produce the best results.

It is therefore an important object of the present invention to provide a new and improved method of inhibiting or controlling the formation of paraffin on surfaces part which hydrocarbons flow.

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Still another important object of the present invention is to provide a new and improved method of controlling or inhibiting the deposition of scale and like materials in wells and on the equipment therein.

Another object of the present invention is to provide a new and improved method of adding surfactants for changing or maintaining the wettability of a formation, breaking emulsions, forming emulsions or other purposes or adding other well treating chemicals to the well fluids as they are produced.

Still another object of the present invention is to provide a new and improved method of adding surfactants for changing or maintaining the wettability of a formation, breaking emulsions, forming emulsions or other purposes or adding other well treating chemicals to the well fluids as they are produced.

A further object of the present invention is to provide a new and improved method of adding chelating or sequestering materials to well fluids as such fluids are produced to provide a prolonged treatment of the well fluids.

Yet a further object of the present invention is to provide a new and improved method of treating well fluids, wherein a plurality of treating liquids may be simultaneously added to the well fluids as they are produced for providing a variety of treatments to the well fluids as desired.

Other objects and advantages of the present invention will become more readily apparent from a consideration of the following description and drawings wherein:

FIG. 1 is a vertical section of a well bore and fracture therein, schematically illustrating the location of fluids after injection; and

FIG. 2 is a vertical section of a well bore and fracture therein, schematically illustrating the fluid flow profile during production and after treatment.

Although many different liquids have been injected or introduced into oil and gas wells and the like for a variety of reasons, none have heretofore been injected for the purpose of providing a long feed back thereof or a prolonged treatment of the well therewith. Under the prior art teachings as exemplified by the paraffin inhibition method of U.S. Patent No. 3,051,653, slowly soluble solid materials have been used to provide prolonged or continuous treatments of a well. Solubilities and melting points must always be taken into consideration when using such solid materials.

In placing the treating materials into a fracture in a well formation, it has been discovered that a longer feed back may result if the treating material is completely dissolved in oil or other solvent, than if such material is slowly soluble and remains in the fracture.

The treating solution of the present invention is preferably a high fluid loss liquid and is displaced in a well formation at a rate sufficient to fracture the formation, but which will also permit the treating liquid to be lost of the face of the fracture and into the formation within the first few feet of the fracture. In carrying out the present invention, it is preferable that the fracture be a horizontal radial one.

The method of the present invention may also be used with vertical fractures, but shorter feed back times of the treating fluid may result.

Referring now to the drawings, the flow patterns of fluids injected into a well during fracturing and the production of fluids from the well after fracturing is completed are schematically illustrated.

In FIG. 1 a well bore 10 is shown with a horizontal fracture 12 extending therethrough. The fracture 12 is illustrated as being sufficiently long to show the pattern of fluids injected into the well bore 10 and fracture 12.

The treating fluid or fracturing fluid containing the treating agent, paraffin inhibitor, bactericide, scale preventative, corrosion inhibitor, emulsion breaker, surfactant, chelating agent or other is injected or pumped into the well bore 10 at a sufficient pressure and rate to create the horizontal fracture 12. The treating fluid 14 is preferably a high fluid loss liquid as defined hereinbelow and is also introduced into the well bore 10 and fracture 12 in such manner that it is substantially lost to the face of the fracture and into the formation 15 within the first few feet of the fracture. This may be readily seen in FIG. 1 wherein near the end of the fracture at point a, the treating fluid 14 has just barely entered the formation and wherein the beginning of the fracture at
point $b$, the treating fluid has been injected relatively far into the formation.

The treating fluid 14 may be further displaced into the formation by the injection of either additional treated fluid or untreated fluid 16. The untreated fluid should preferably be of low fluid loss to limit displacement of fluid 14. The amount of fluid injected into the formations will govern the extent the fluids 14 and 16 are extended into the formation 15, but the flow pattern as observed in FIG. 1 will exist without regard to the amounts of fluid injected into such formation 15.

It can therefore, readily be seen that the treating agent or treating fluid 14 reaches its maximum penetration into the formation or producing sand 15 at or near the well bore.

It can also be appreciated that the treating agent need not be distributed throughout the fracturing fluid, but may be placed or dispersed in only the first portion or spear head of fracturing fluid injected into the well. Economics, size of formation to be treated, and type of treatment to be made will largely control the amount of treating agent used in this operation.

After the fluids have been introduced into the formation and the well has been placed on production, the fluids injected into the well and the natural well fluids will be produced from the formation, through the fracture and into the well bore in a particular pattern.

This pattern may best be seen in FIG. 2 wherein fluids from the producing zone 20 enter the fracture 12 as illustrated by the flow lines 21.

The dotted lines 23 illustrate the pressure profile along each of the flow lines 21. From these flow lines 21 and equipotential lines 23, it is easily seen that as fluids are produced from the zone 20, the heaviest rate of flow is near the end of the fracture 12 at a point $c$, and that there is little flow of fluids from a point $d$, near the well bore 10 or beginning of the fracture 12.

The treating liquid which has been lost to the formation nearest the well bore will therefore be slowly produced back with the producing fluids. As only a few parts per million are required of most treating agents to provide an effective control over the problems, a continuing control of the problem is maintained over a long period of time.

The amount of treating agents required or needed for a particular job is readily determined by one skilled in the art.

Two articles have been written by Dr. H. K. van Poolen which explain in detail the pattern of fluid production upon fracturing a formation. These articles are entitled "Productivity Permeability Damage in Hydraulically Produced Fractures" and "Do Fracture Fluids Damage Productivity" presented at the Spring Meeting of the Southwestern Division of Production, American Petroleum Institute in Dallas, Texas, March 6–8, 1957, and published in the May 27, 1957 issue of The Oil and Gas Journal, respectively.

A high fluid loss liquid is defined herein as a liquid having an effective E value ($E_{fa}$) of 0.003 ft./min. or higher as explained in detailed hereinbelow.

The leak-off rate of an injected fluid to any given area is dependent on each of the following: differential pressure from fracture to formation, fluid viscosity, time of exposure to fluid (decreasing as the square root of time), formation permeability, porosity, saturation classification of the producing formation, and the compressibility of formation fluids.

Rate of fluid leak-off may be mathematically described by either the term $E_r$ which describes the viscous resistance to flow into permeability or by $E_p$ which describes the restriction to penetration due to the low compressibility of formation fluids. In saturated formations $E_{sat}$ is used to calculate leak-off rates due to a combination of $E_r$ and $E_p$. These terms are mathematically determined or described by the following.

\[
E_{fa} = \frac{1}{E_r} + \frac{1}{E_p} = \frac{1}{E_r} + \frac{1}{E_p} = \frac{1}{E_r} + \frac{1}{E_p}
\]

\[
E_{fa} = 0.0469A_p\mu_0V/KAPI, \text{ (ft.}/\text{min.}^{1/2})
\]

\[
E_{fa} = 0.0374A_p\mu_0V/KAPI, \text{ (ft.}/\text{min.}^{1/2})
\]

Where:

- $\phi$ = formation porosity as a decimal
- $K$ = formation permeability, darcys (1 darcy = 1000 millidarcies)
- $\mu$ = viscosity of injected fluid at bottom hole temperature, cps.
- $Dp$ = differential pressure, p.s.i. (bottom hole treating pressure less reservoir pressure)
- $C_r$ = reservoir fluid compressibility factor, p.s.i.$^{-1}$

Formation conditions will, to a great extent, control the limits of these values, and thus require variations in the treatment method to obtain the proper treating fluid penetration profile for desired protection.

The penetration profile is then determined based on the described example conditions by the solution of a stoichiometric material balance in which the injected volume equals the loss volume to a given area plus the volume of generated fracture based on an incremental time analysis. The width of the fracture during injection can be calculated by accepted methods based on rock properties, fluid properties, volume injected and rate of injection. The results of this analysis determine the rate of fracture generation, rate of leak-off and total leak-off volume to any increment of area within the generated area.

Based on this data, the volumetric treating fluid contribution to the total production from any increment of fracture area can be determined.

This permits the calculation of feed back rate, concentration of treating chemical within the produced fluid, changes in concentration of treating chemical with time and the maximum time over which protection can be expected.

From these calculations suitable volumes of injection fluid, rates of injection or a combination of the above can be determined to provide the desired protection requirements for particular formation conditions.

An illustration of the determination of $E_{fa}$ for a particular job and formation conditions is set forth in Example I.

**Example I.—Job and formation conditions**

- Formation permeability—20 md...2 darcys
- Formation porosity—15 percent = 0.15
- Reservoir fluid compressibility factor—1 x 10$^{-5}$, p.s.i.$^{-1}$
- Differential pressure during injection—2000 p.s.i.g.
- Viscosity of injection fluid—1.0 cp.
- Injection rate desired—2 b.p.m.
- Injection volume—3000 gallons
- Producing rate of oil following treatment—20 b.p.d.
- Formation saturated
- Horizontal fracture induced

For these particular formation conditions, an $E_{fa}$ of 0.120 ft./min.$^{1/2}$ was calculated with the value of $E_p$ being 0.013 ft./min.$^{1/2}$. The resulting $E_{fa}$ for the saturated reservoir was determined to be 0.0117 ft./min.$^{1/2}$.

For the conditions cited in this example penetration distances are calculated for increments of area from the well bore zero ft. to an area of 1947 ft.$^2$ generated at a time of 10 minutes. The losses to these areas are based on the total pumping time of 35 minutes. The profile and volume lost to the area increments beyond 25 feet were not calculated in this example. This could be done by determining the area exposed in each minute of pumping ($A_1$ through $A_{25}$), thereby determining the period of time in which fluid is lost to that area. This time is the pumping time minus the time required before exposure. This time would then determine the volume lost to that area and the resulting profile for calculation of feed back rate.
The subsequent solution of this problem in the described manner for only that portion of material contained in the area described above indicates a feed back rate of 2.52 gallons per day for 498 days followed by a feed back rate of 0.84 gallon per day for an additional 312 days. The calculated protection time would have been in excess of this time had the solution been carried out for the total area generated in 35 minutes.

The following variables will alter the calculated protection time:

1. Formation permeability
2. Formation porosity
3. Differential treating pressure
4. Rock properties
5. Fracture orientation
6. Fluid viscosity
7. Production rate following treatment

Treatments can be designed for pre-determined periods of protection in the same general mathematical manner as shown above.

The present invention may be utilized in either natural or artificial fractures, and the treating liquid may be injected in a previously fractured formation or may be injected simultaneously with the creation of the fracture.

When the treating liquid is injected into a formation prior to a fracturing treatment, the fracturing fluid should have a fluid loss less than that of the treating liquid, and preferably have an effective E value (E_{eff}) less than 0.001.

Although it is generally preferred that the treating liquid be a low viscosity liquid (I.e. about 1 cp. or less), it can be appreciated that considerably higher viscosity liquids may be used in highly permeable formations.

Broadly, the present invention relates to a new and improved method of treating wells for providing a continuing or prolonged treatment thereof, namely paraffin control, corrosion inhibition, scale prevention, bacteria control, well stimulation and similar problems requiring the injection of chemicals into a well.

What is claimed is:

1. A method of providing a desired type of a continuing or prolonged treatment of a well, comprising the step of introducing into a producing formation a desired treating liquid having a high fluid loss at a pressure sufficiently great to cause the treating liquid to enter the formation and be substantially lost to a fracture face near the well bore, whereby said treating liquid is slowly produced back with the well fluids; said high fluid loss liquid being one having an effective E value of a minimum of about 0.003 ft./min. ft. ², wherein E_{eff} is determined by the following formula:

\[
\frac{1}{E_{eff}} = \frac{1}{E_s} + \frac{1}{E_R}
\]

\[
E_s = 0.0469 \sqrt{K \Delta P / \mu} \quad (\text{ft.} / \text{min.} / \sqrt{2})
\]

\[
E_R = 0.0374 \sqrt{\Delta P \sqrt{K C_i / \mu}} \quad (\text{ft.} / \text{min.} / \sqrt{2})
\]

Where:
- \(\varphi\) = formation porosity
- \(K\) = formation permeability
- \(\mu\) = viscosity of injected fluid
- \(\Delta P\) = differential pressure
- \(C_i\) = reservoir fluid compressibility factor

2. The method of claim 1 wherein the treating liquid is selected from the group consisting of a paraffin inhibiting agent, a corrosion inhibiting agent, a scale deposition preventative agent, a surface active agent, a bactericide, a chelating agent, and an emulsion breaker.

3. A method of providing a predetermined type of a continuing or prolonged treatment of well fluids produced from underground strata penetrated by the bore of a well, comprising the steps of:

(a) introducing into the well a desired well treating liquid having a high fluid loss, said high fluid loss liquid being one having an effective E value of a minimum of about 0.003 ft./min. ², wherein E_{eff} is determined by the following formula:

\[
\frac{1}{E_{eff}} = \frac{1}{E_s} + \frac{1}{E_R}
\]

\[
E_s = 0.0469 \sqrt{K \Delta P / \mu} \quad (\text{ft.} / \text{min.} / \sqrt{2})
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E_R = 0.0374 \sqrt{\Delta P \sqrt{K C_i / \mu}} \quad (\text{ft.} / \text{min.} / \sqrt{2})
\]

Where:
- \(\varphi\) = formation porosity
- \(K\) = formation permeability

4. The method of claim 3 wherein the treating liquid is selected from the group consisting of a paraffin inhibiting agent, a corrosion inhibiting agent, a scale deposition preventative agent, a surface active agent, a bactericide, a chelating agent, and an emulsion breaker.

5. A method of treating underground strata containing either a natural or artificial fracture therein and penetrating by the bore of a well for providing a desired continuing or prolonged treatment of the well, comprising the steps of:

(a) introducing into the well a desired well treating liquid having a high fluid loss, said high fluid loss liquid being one having an effective E value of a minimum of about 0.003 ft./min. ², wherein E_{eff} is determined by the following formula:

\[
\frac{1}{E_{eff}} = \frac{1}{E_s} + \frac{1}{E_R}
\]

\[
E_s = 0.0469 \sqrt{K \Delta P / \mu} \quad (\text{ft.} / \text{min.} / \sqrt{2})
\]

\[
E_R = 0.0374 \sqrt{\Delta P \sqrt{K C_i / \mu}} \quad (\text{ft.} / \text{min.} / \sqrt{2})
\]
Where:
\( \phi \) = formation porosity
\( K \) = formation permeability
\( \mu \) = viscosity of injected fluid
\( \Delta P \) = differential pressure
\( C_T \) = reservoir fluid compressibility factor

(b) causing said treating liquid to contact a section of the underground strata having a fracture therein;
(c) applying sufficient pressure to said treating liquid to cause said liquid to enter said strata, whereby said treating liquid is substantially lost to the face of the fracture and into the strata section within the first few feet of the fracture; and
(d) allowing the treating liquid to be produced back with the well fluids thereby providing a continuing treatment of the well by the treating liquid.

6. The method of claim 5 wherein the treating liquid is selected from the group consisting of a paraffin inhibiting agent, a corrosion inhibiting agent, a scale deposition preventative agent, a surface active agent, a bactericide, a chelating agent, and an emulsion breaker.

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