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[54] **METHOD AND APPARATUS FOR CONTINUOUSLY INJECTING A FLUID INTO A PRODUCING WELL**

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[51] **Int. Cl.** **E21b 43/00**

[58] **Field of Search** ..... 166/73, 77, 243, 166/244 D, 268, 310, 311, 312, 315

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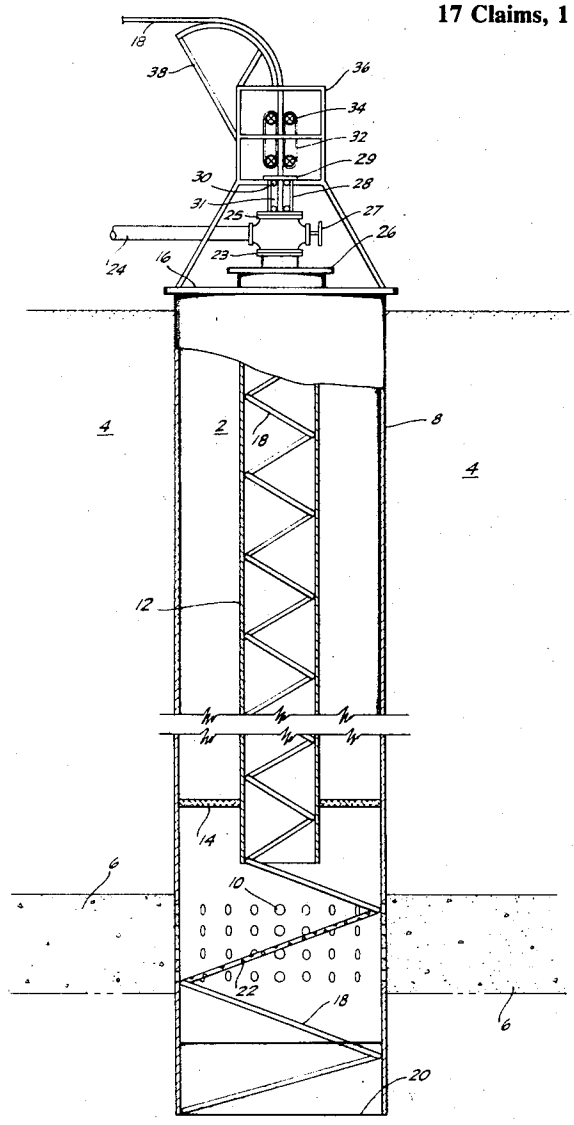
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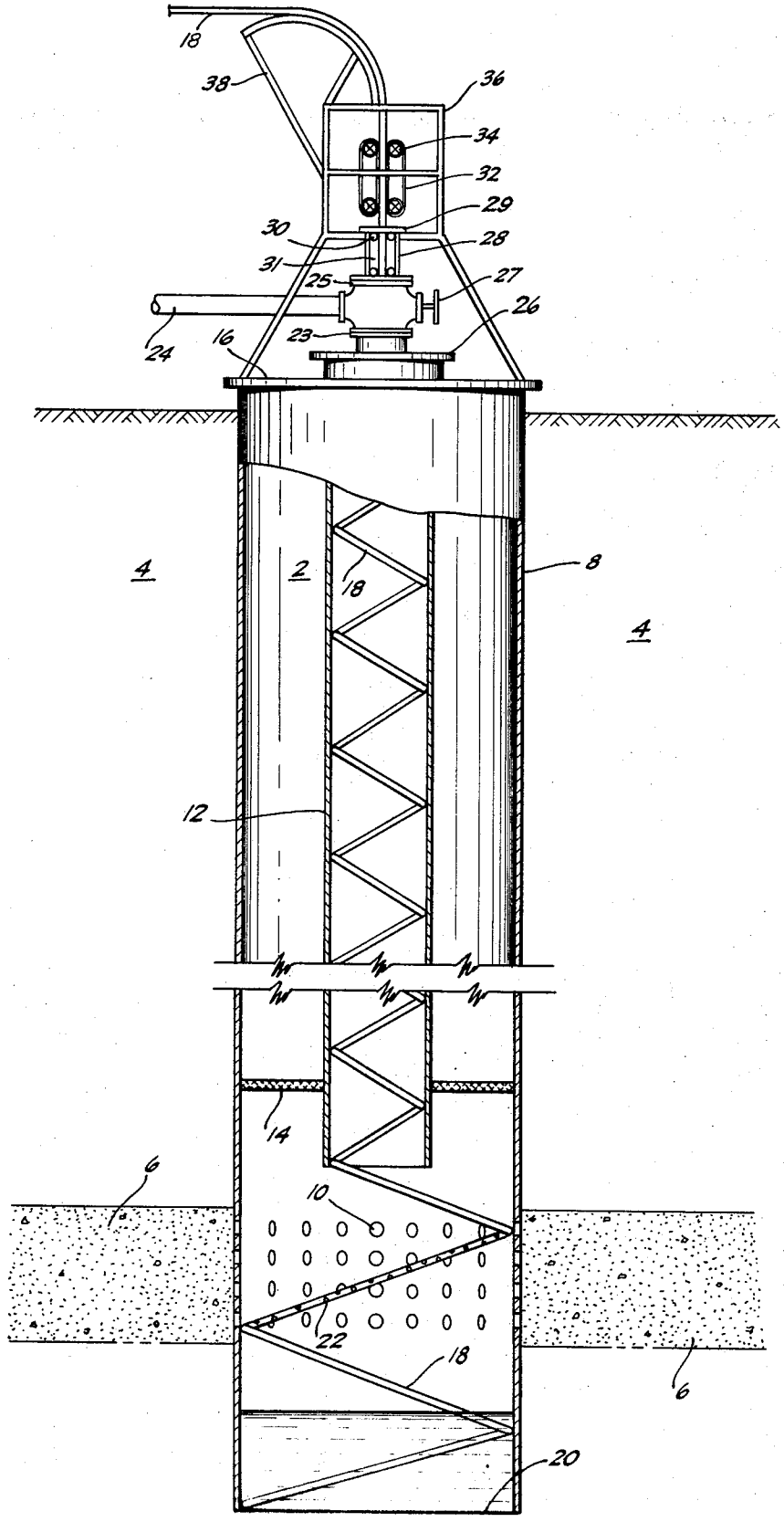
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[57] **ABSTRACT**

A method and apparatus for continuously injecting a treating fluid into a recovery well while simultaneously producing from the well is disclosed. A small perforated injection tube is inserted into the production tubing of the well and a sufficient length of tube is introduced beyond that required for complete suspension within the well to cause the tube to spiral upwardly within the tubing in helical contact with the tubing wall. The perforations are located at well bore elevations adjacent the fluid-bearing zones traversed by the well to allow treating fluid within the tube to enter the well bore at these elevations. In operation, a treating fluid is forced into the injection tube and into the well bore at the selected elevations, and at the same time formation fluids are recovered from the well.

17 Claims, 1 Drawing Figure




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METHOD AND APPARATUS FOR CONTINUOUSLY INJECTING A FLUID INTO A PRODUCING WELL

DESCRIPTION OF THE INVENTION

This invention relates to the recovery of oil, gas and other fluids from subterranean formations and, more particularly, relates to a method and apparatus for continuously injecting a treating fluid into a recovery well while simultaneously producing from the well.

In the recovery of formation fluids, such as, crude petroleum oil, natural gas, steam, and the like, from subterranean zones, a well is drilled into the formation so as to traverse the fluid-bearing zones. The formation fluids within these zones are under a substantial pressure from the overbearing rock, etc., and are forced through the zones into the well bore. The fluids are recovered from the well through a production tubing suspended within the well bore and terminating above the fluid-bearing zones.

The formation fluids often contain organic and inorganic scale-producing materials which, over prolonged production periods, tend to form scale deposits within the formation immediately adjacent the well bore, on the side of the well bore casing and along the inside of the production tubing. In many instances, these deposits become so thick and accumulated that complete shutdown of the well is necessary for cleaning and removal of the deposits. Additionally, the formation fluids often contain vaporous material which is highly corrosive to exposed metallic surfaces, such as the production tubing. By continuously injecting a scale and corrosion inhibitor into the well bore adjacent the producing zones the corrosion and deposition of scale on the casing wall and inner surfaces of the production tubing can be substantially reduced and in some instances eliminated.

It has been proposed to continuously inject a corrosion and scale inhibitor into the well bore through a small injection tube suspended within the production tubing. This method, while achieving the objectives of reduced scale deposition and corrosion, is seriously burdened by mechanical limitations. For example, in the suspension of the injection tube from the formation surface, the tube near the well head supports the entire suspended tube weight and accordingly is subjected to the greatest stress. In instances where deep wells are encountered the total tube weight can be sufficient to cause tube breakage or failure. Moreover, this total weight is increased when the treating fluid is injected into the tube by the weight of an equivalent column of fluid.

An additional problem is encountered when fluids are produced from the well. The formation fluids flow upwardly within the production tubing at high flow rates and cause the suspended injection tube to oscillate and collide with the tubing wall. The tube oscillation causes weak spots to develop in the tube and increases the probability of injection tube failure. This problem is particularly detrimental where the formation fluid is a gas, such as natural gas or steam.

Another problem encountered with injection tubes suspended from the well head is that temperature fluctuations within the well bore cause excessive thermal expansion. Generally it is desirous to terminate the injection tube, or at least provide perforations therein, at well bore elevations corresponding to the production zones. In deep wells, the length of the tube and corresponding location of the perforations are substantially affected by temperature fluctuations within the well bore. For example in a well 20,000 feet deep, a temperature change of 100°C. is sufficient to cause most injection tubes to expand or contract a distance of 27 feet. An expansion or contraction of this magnitude hinders the introduction of treating fluid at the correct well bore elevation.

An additional problem is realized when it is desirous to recover the suspended injection tube from the well at the termination of the natural production. Over prolonged production periods some scale deposits inevitably form within the production tubing at several locations. If the injection tube is in proximity to these locations, the deposits tend to cement the tube to the wall of the production tubing. By pulling on the injection tube at the formation surface the cementing effect from each of the scale deposits collectively retard any movement of the tube. If there are numerous cementing deposits, the pulling force on the tube near the surface will ultimately result in tube failure.

Thus, it is apparent that a need exists for a method and apparatus for introducing a fluid into a producing well in the vicinity of the producing strata while simultaneously producing from the well, which are not detrimentally affected by temperature fluctuations or fluids flowing at high velocities within the well, and apparatus which can be simply installed and recovered from the well.

SUMMARY OF THE INVENTION

This invention contemplates a method and apparatus for injecting a treating fluid into a recovery well which avoids the aforementioned difficulties. In this method and apparatus, a small injection tube is inserted into a suspended production tubing within a recovery well. The tube has an outside diameter from 1 to 20 percent of the inside diameter of the suspended tubing. A sufficient length of injection tube is introduced into the tubing beyond that required for complete suspension so that it is constrained in a spiral configuration within the production tubing and contacts the innter wall thereof in a helical manner. I have found that the continuous helical contact between the injection tube and the production tubing wall supports the tube over the vertical extent of the well. By mounting the injection tube in this manner, the stress on the tube at the surface from the weight of the lower portion can be substantially reduced and in fact can be eliminated.

In many instances it may be advantageous to terminate the production tubing above the fluid-bearing zones of the formation and a considerable distance from the bottom of the well bore. In these instances the injection tube is spiralled within both the production tubing and that portion of the well bore below the terminus of the production tubing. Thus, in this embodiment the injection tube is in helical contact with the wall of the production tubing and with the bore hole between the bottom of the well and the terminus of the production tubing.

The practice of this invention can also be applied to wells which do not contain a suspended production tubing. In these instances the injection tube is spiralled within the well bore from the bottom of the well to the formation surface.

A particular advantage of this invention is that the injection tube can be installed without killing the well

and in fact can be inserted concurrently with the recovery of formation fluids from the same production tubing. Hence, it is not necessary to shut down production or kill the well in order to install the apparatus of this invention.

After the installation of the injection tube, a treating fluid is pumped into the tube at the formation surface and a regulated amount of the fluid is discharged into the well bore. A portion of the treating fluid comes into contact with the well bore casing and the remainder is carried along with the recovered formation fluids through the production tubing and contacts the inner surfaces of the tubing. In this manner, both the well bore casing and production tubing can be continuously treated during production.

At the termination of the natural production from the well or whenever desired, the helically mounted injection tube is easily removed from the well. Small scale deposits which form between the injection tube and the well of the production tubing or bore hole do not pose a serious problem in retarding the removal of the tube since the effect of numerous deposits is not cummulative. The tube is simply uncoiled from within the production tubing and bore hole successively breaking individual scale deposits.

BRIEF DESCRIPTION OF DRAWING

The invention is further illustrated by the attached DRAWING which displays a cross-section view of a recovery well containing an injection tube mounted in accordance with this invention.

DESCRIPTION OF THE PREFERRED EMBODIMENTS

As shown in the DRAWING a bore hole **2** is drilled through a subterranean formation **4** containing a permeable fluid-bearing zone **6.** The well bore **2** is protected with a suitable well casing **8** which is sealed at the surface by flange **16.** The casing is perforated with slots **10** adjacent permeable zone **6** to allow fluid from the zone to enter the bore hole **2.** A production tubing **12** is suspended within the well bore **2** and fluid-tightly sealed therein at the well head with flange **26.** The production tubing **12** terminates above the permeable zone **6** and a packer **14** is placed in the well bore near the terminal end of the tubing.

An injection tube **18** is helically coiled within the production tubing **12** and within the lower portion of well bore **2** between the terminus of the tubing **12** and well bottom **20.** By mounting the tube in a helical manner, the outer perimeter of the tube is in continuous contact with the wall of tubing **12** and with the well casing **8** below the terminus of the production tubing **12.** In one embodiment, the injection tube is perforated with apertures **22** at a location adjacent the permeable zone **6** and perforated casing **8.**

The injection tube extends through the top of the production tubing, through flange **23,** valve assembly **27** and flange **25** and passes through a seal chamber assembly **28.** Flanges **23** and **25** fluid tightly seal the production tubing to the seal chamber assembly and fluid recovery line **24** through valve **27.** The seal chamber assembly **28** is comprised of a cylindrical chamber **31** and flexible resilient seals **30** which fluid tightly encompass the injection tube as it passes through each end of the assembly. Hydraulic pressure is applied to the inside of chamber **31** so as to force the seals **30** against each end of the seal chamber and in contact with the injection tube. By applying the appropriate amount of pressure, the loss of fluid from the production tubing through the valve assembly can be minimized and in some instances eliminated.

The injection tube passes through flange **29** at the top of seal assembly **28** and contacts two belts **32.** The belts intimately contact the tube and provide a means for feeding the tube into the well at a given rate or for withdrawing the tube from the well. The belts held tightly adjacent the injection tube with pulleys **34.** The pulleys and belts are supported above the top of the well and production tubing by hanger **36** and provide a means for both supporting and regulating the insertion rate of the tube during its installation and removal.

Above the belt drive, the tube passes over a guide assembly **38** which provides a smooth arc of approximately 100° and guides the injection tube from its source, generally a large spool, into the abutting belts. The surface end of the tube is connected to a supply pump, not shown.

In mounting, the injection tube is uncoiled from a large diameter spool shipped to the well site and the end of the tube is passed over the guide assembly **38** and between the two belts **32** into the center of the seal assembly **28** and production tubing **12.** A sufficient amount of hydraulic pressure is applied to the seal assembly to prevent the discharge of production fluid from the production tube into the seal chamber. The two belts are revolved at a constant rate to straighten and introduce the tube into the well at the desired rate. A weighing device is connected to the pulleys through bracket **36** to measure the weight of the injection tube introduced into the well. The measured weight of the tube will pass through a maximum value when the tube contacts the bottom of the well. When this occurs an additional length of injection tube is slowly introduced into the well to cause the tube to spiral within the well bore and production tubing. When the measured weight of the tube attains its minimum selected value, the tube insertion is terminated.

A treating fluid is pumped into the injection tube **18** and is discharged into the well bore adjacent zone **6** through perforations **22.** Simultaneous with the injection of treating fluid, formation fluids are produced from the well and recovered through tubing **12** and conduit **24.**

The drawing only represents one embodiment of this invention and it is apparent that numerous modifications can be made to the apparatus as shown without deviating from the inventive concepts disclosed herein. For example, a plurality of spaced production zones can be treated from the same injection tube, or a liquid may be produced from one zone and a gas from another, or several production tubings may be inserted into the well with each tubing containing a helically mounted injection tube. Those embodiments which may be made without changing the essence of the invention are considered within th scope of this invention.

INSERTION AND MOUNTING OF INJECTION TUBE

The injection tube is inserted and mounted within the production tubing after the well is completed, and in order to avoid production delays, it is preferred to insert and mount the tube while simultaneously produc-

ing from the well. The following technique represents a preferred embodiment of this invention for inserting and mounting the injection tube within the well.

A well is completed and a production tubing suspended within the well from the surface and terminating immediately above the production zone or zones. An expandable packer is placed immediately above the terminus of the production tube to seal the producing zones from the above non-productive zones. The production tubing is placed under a strain by placing an upward pressure on the tubing at the surface tending to pull the same from the well. The packer at the bottom of the well prevents any extractive movement by the tubing thereby causing the tube to be in a strained condition within the well bore. This strain reduces the expansion and contraction of the production tubing within the well caused by temperature fluctuations during normal production.

After the production tubing has been mounted under a strained condition, a small injection tube having a smooth outside diameter, generally from one-sixteenth to one-half inch and preferably from one-eighth to three-eighths inch, is introduced into the production tubing. The cummulative weight of the injection tube is continuously measured at the well head to determine the amount and length of tube previously introduced into the well. Immediately before the tube contacts the bottom of the well bore the total measured weight registers a maximum value. As additional lengths of the injection tube are lowered into the well, the tube begins to spiral upwardly along the wall of the well bore and production tubing. In order to prevent the collapse of the tube within the well, the additional lengths of injection tubing are slowly inserted into the well preferably at a rate of about 1 to 60 feet per minute and more preferably from 5 to 25 feet per minute.

As the injection tube contacts the wall of the well bore and production tubing, the measured total weight at the formation surface continuously decreases. The introduction of injection tube is continued until the measured weight of the injection tube has been reduced by about 80 to 100 percent of its maximum value and preferably by about 95 to 100 percent of its maximum value.

The injection tube when mounted within the production tubing and well casing forms a helix having a period of 10 to 50 times the diameter of the enclosure, e.g. the production tubing or well casing. As referred to herein, the helical period is defined as the vertical rise of the injection tube for the tube to traverse 360°. This period varies depending upon the thickness and diameter of the tube, the material of construction, the temperature and the diameter of the production tubing and well bore, etc. Generally, for a conventional 5-½ inch diameter well casing, the helical period of an ⅛ to ⅜ inch injection tube with a wall thickness between 0.02 and 0.028 inch varies from about 5 to about 10 feet and usually from 5 to about 7 feet, and for a conventional 3-½ inch diameter production tubing, the helical period varies from about 7 to about 15 feet and usually from 8 to about 12 feet.

In many instances, the recovery well is operated under very high pressures, such as, from about 1,000 to about 15,000 psig. When these pressures are encountered it is preferred that a stream of inert gas or liquid be injected into the injection tube at a pressure preferably greater than the pressure of the well during its descent in the production tubing to prevent intrusion of debris into the tube and to prevent escape of the production fluid to the atmosphere through the injection tube. In instances where the production fluid is natural gas, care must be taken to prevent the accumulation of explosive amounts of gas from seepage into the atmosphere from the injection tube.

Where a perforated injection tube is inserted into a high pressure well, the perforations must be temporarily sealed at the formation surface prior to the tube insertion into the well to prevent production fluid from escaping to the atmosphere through the perforations in the tube. In one method, the perforations are sealed with a solid substance having a melting point below the temperature of the well bore. In this embodiment, the solid sealant must have strength sufficient to withstand the pressure within the well bore and have a melting point below the temperature of the well adjacent the producing zones. An exemplary sealant is ASCRCOLO BEND 158 which is an alloy of 50 percent Bismuth, 13 percent Tin, 10 percent Cadmium and 20 percent Lead having melting point of about 158°F and marketed by American Smelting and Refining Company.

INJECTION TUBE

The injection tube is of tubular cross-section and can be constructed of any material which is capable of withstanding the physical strain when fully suspended within the well to be treated and the temperature conditions existent within the well bore. Generally, however, the material of construction is selected from that which is commercially available, such as metal alloys, like steel, iron-nickel-chromium alloys, such as, Stainless Steel 300 and 400 series; Nickel-copper-iron-chromium alloys, such as Inconel X, M, W, 600, 700 series, etc., nickel-cobalt-iron-chromium alloys, such as Incoloy, Incoloy T, 825, 901, etc., nickel-copper-iron alloys, such as Monel, Monel 402, 403 and K, R, H, and S Monel, etc., nickel-molybdenum-chromium alloys, such as Hastelloy Alloy B, C, D, F, R-235, X, etc. Other materials of construction include Nylon, polyesters, polyolefins, such as polypropylene, etc., Fiberglass, polyvinyl chloride, etc. Selection of these polymeric materials of construction should be made only where the bottom hole conditions of the well is not beyond that which the material can withstand for purposes of this invention. For wells that are deeper than 1,000 feet, it is preferred that the material of construction be selected to have a yield strength greater than 50,000 psi and preferably greater than 100,000 psi.

The injection tube can be constructed of several individual segments which are sequentially joined at the surface during insertion into the production tube in a manner similar to the installation of the production string. In a preferred alternative embodiment, the injection tube is constructed of a single length. In this embodiment, the tube is coiled around a large diameter spool which may be transported to and from the recovery well.

The injection tube can also have a variable wall thickness, as for example, a tube having a relatively thick wall at elevations near the formation surface and a thinner wall at lower elevations. In this manner the portion of the injection tube subjected to the maximum strain has the thickest wall and is capable of withstanding the greatest stress.

The injection tube is preferably perforated at selected locations prior to its insertion into the recovery well. The location of these perforations are preselected so that when the tube is fully installed in the well, they are adjacent the producing zones. The location of these perforations can be calculated by the following formula:

$$L = (E/P)\ (\sqrt{\pi^2 D^2 + P^2})$$

where

L is the distance of the perforations from the end of the injection tube inserted into the well bore;

E is the elevation of the producing zone from the bottom of the well;

P is the helical period; and

D is the diameter of the well bore.

The above equation only represents a simplified method of determining the location (L) of the perforation and does not take into account the expansion due to temperature fluctuations or stresses.

PROCESSES

The method and apparatus of this invention have particular application in the inhibition of organic and inorganic scale deposition and corrosion in oil, natural gas and steam recovery wells. In the process a scale or corrosion inhibitor such as, phosphated hydroxyamines and N-substituted polyamines or preferably a combination of both are injected into the injection tube at the formation surface at a rate of from one-tenth to 10 gallons per day. A portion of the inhibitors released into the well bore contacts the wall of the well casing and provides some protection against scale deposition. The remainder of the inhibitors is swept up the well with the production fluids and contacts the wall of the production tubing thereby providing some protection against scale deposition and corrosion.

The method and apparatus of this invention can also be advantageously employed in reducing corrosion and erosion in steam recovery wells. In this application, a corrosion and erosion inhibitor such as the condensation product of triethanolamine and dimerized linoleic acid, is injected into the well bore adjacent the steam bearing zones through the helically wound injection tube. The inhibitor is swept up the well with the steam and a portion thereof contacts the exposed metallic parts and provides some protection against corrosion. Another portion of the inhibitor contacts small solid particles entrained by the fast moving steam and forms a soft resinous residue around the solid particles thereby reducing the abrasiveness of the entrained particles.

Although the invention has been described as particularly applicable to scale and corrosion inhibition, the method and apparatus can be employed in any well treating process wherein it is desirous to inject a treating fluid into the well bore and adjacent formation. The invention is further described by the following examples which are illustrative of specific aspects of the invention and are not intended as limiting the scope of the invention as defined by the appended claims.

EXAMPLE 1

This example is presented to demonstrate the method of helically mounting a small injection tube in a simulated well. The simulated well consisted of an elongated clear Plexiglass pipe having a 73 inch long upper section with a 2-½ inch inside diameter and a 65-½ inch long lower section with a 4-inch inside diameter. The pipe is vertically mounted above a solid plate representing the well bottom. A small seamless tube constructed of Incoloy 825 alloy and having an outside diameter of 0.295 inch and a wall thickness of about 0.028 inch is inserted into the Plexiglass pipe through the upper section. After the injection tube is inserted into the simulated well sufficient to contact the solid plate at the base of the lower section, a 62 pound force is applied to the tube at the top of the well to force an additional length of tube into the Plexiglass pipe. The injection tube forms a smooth helix in both the upper and lower sections of the Plexiglass pipe with a helical period of about 8 feet in the upper section of the pipe and a period of about 7 feet in the lower section. The injection tube is completely supported in both portions of the Plexiglass pipe by bearing against the sidewalls with the exception that approximately 14 inches of the tube was unsupported directly below the junction of the upper and lower Plexiglass sections. An additional one hundred pound force is applied to the tube at the top of the simulated well with little effect on the helical period. This experiment demonstrates the helical mounting of an injection tube within a conduit and the ability of the conduit to completely support the injection tube when mounted in this manner.

EXAMPLE 2

This example is presented to illustrate the practice of this invention in a gas recovery well. The well is drilled to a depth of 20,000 feet, traversing a gas producing zone at the inerval of 19,850 feet to 19,880 feet. The well is completed with a 5-½ inch diameter well casing perforated at the production interval with one-hundred, ¼ inch diameter 3-inch long slots. A 3-½ inch diameter production tubing is suspended within the production welll and terminates above the gas producing zone at a dpeth of 19,800 feet. A packer is placed immediately above the terminus of the production tubing. The well is placed on stream and during full production approximately 10,000 standard cubic feet per minute of natural gas is recovered. The pressure at the well bore head is measured and varies from 1,000 psig to 1,500 psig during zero production.

A small seamless injection tube having a length of 24,000 feet and coiled around a 5 foot diameter spool is provided at the well head. The injection tube is introduced into the center of the production tubing through a small aperture at the top of the tubing. The injection tube is constructed of Incoloy 825 and has an outside diameter of 0.205 inches with a wall thickness of 0.028 inch.

The tube is perforated at locations calculated by equation 1 on page 10 as follows:

$$L = (E/P)\ (\sqrt{\pi^2 D^2 + P^2})$$

In the equation the elevation (E) of the production zone is from 20 to 50 feet from the bottom of the well, the helical period (P) with the injection tube is 6 feet and the diameter (D) of the well casing is 5-½ inches. The location (L) is calculated as follows:

$$L = (20/6)\ \sqrt{\pi^2 (5.5/12)^2 + (6)^2}$$

$$L + 20.6 \text{ feet}$$

$$L = (50/6)\ \sqrt{\pi^2 (5.5/12)^2 + (6)^2}$$

$$L = 51.5 \text{ feet}$$

Thus, the injection tube is perforated between the interval of from 20.6 feet to 51.5 feet to correspond with the production zone when the tube is fully inserted into

the well. Each perforation is filled with a sealant of ASARCOLO BEND 158 having a sharp melting point of 158°F prior to its insertion into the well bore to prevent natural gas from entering the injection tube through the perforations. The temperature of the well at approximately 19,880 feet is 350°F and is sufficient to melt the ASARCOLO BEND and opens the apertures. A nitrogen gas stream is passed through the injection tube during its introduction into the well bore at a pressure of about 1,500 psig to prevent the intrusion of debris into the tube and to prevent the escape of natural gas to the atmosphere through the injection tube.

The injection tube is straightened upon leaving the spool and passes through a hanger directly above the production tubing. The hanger is mounted on a weighing device which weighs that portion of the injection tube introduced into the production tubing. The total weight of the injection tube passes through a maximum of approximately 2,400 pounds when the tube contacts the bottom of the well, and an additional length of tube is introduced into the well at a rate of about 10 feet per minute to cause the tube to spiral within the well. When the total weight drops to 0 pounds, the tube insertion is ceased and the small aperture in the production tubing at the surface is fluid-tightly sealed around the injection tube with a lead sealant. The injection tube has a helical period in the well bore below the termination of the production tubing of about 6 feet and within the production tubing of about 7 feet.

A scale and corrosion inhibitor is injected into the injection tube at the rate of 20 gallons per day, 2 gallons per day of corrosion inhibitor and 18 gallons per day of scale inhibitor. The scale inhibitor is the phosphate ester and N,N′-tetraethanolethylene diamine and is dissolved in water at a concentration of one pound per gallon. The corrosion inhibitor is a combination of 30 weight percent aminoethylethanol amine, 20 weight-percent isobutanol and 80 percent kerosene.

EXAMPLE 3

A well is drilled to a depth of 6,000 feet through a geothermal formation traversing a steam-bearing zone at the interval of 5,950 feet and 6,000 feet. The well is completed with 5-½ inch diameter well casing having perforations adjacent the production interval. A 3-½ inch inside diameter production tubing is suspended within the production well and terminates at a depth of 5,900 feet. A packer is placed immediately above the terminus of the production tubing. The well is placed on stream and during full production approximately 20,000 standard cubic feet per minute of steam is recovered. The pressure at the well bore head is measured and varies from 150 to 400 psig during full production.

A small seamless injection tube having a length of 6,200 feet is introduced into the center of the production tubing through a small aperture at the top of the tubing. The injection tube is constructed of Incoloy 825 and has an outside diameter of 0.205 inches with a wall thickness of 0.028 inches.

The tube is suspended in the well and after contacting the bottom thereof an additional length of tube is inserted therein at a rate of about 2 feet per minute. The injection tube is continuously fed into the well until no more tube will freely go into the well under its own weight. The tube is then fluid-tightly sealed within the production tubing to prevent the escape of steam to the atmosphere.

A corrosion inhibitor comprising 95 weight-percent water, 2 weight-percent diethylene triamine and 3 weight-percent of an acidic triester prepared by the condensation of triethanol amine and dimerized linoleic acid, is thereafter injected into the injection tube at a rate of 2 gallons per hour.

Although I have illustrated the present invention in connection with specific embodiments thereof, it is not intended that the illustrations set forth herein shall be regarded as limitations upon the scope of the invention, but rather, it is intended that the invention be defined by the limitations and their equivalents set forth in the following claims.

I claim:

1. A method of injecting a treating fluid into a recovery well having an open-ended production tubing suspended therein and traversing at least one permeable subterranean producing zone, which comprises:

inserting an injection tube into the production tubing of said well, said tube having an outside diameter of from 1 to 20 percent of the inside diameter of said production tubing;

introducing a sufficient length of said injection tube into said production tubing to contact the bottom of said well and to spiral within said production tubing in helical contact with the tubing wall; and

injecting a treating fluid into said injection tube.

2. The method defined in claim **1** wherein said injection tube is perforated at an elevation adjacent the subterranean producing zone.

3. The method defined in claim **1** wherein said injection tube in said production tubing has a helical period of from 5 to 10 feet.

4. A method of treating a recovery well having an open-ended production tubing suspended therein and traversing at least one permeable subterranean zone containing petroleum oil, hydrocarbon gas, steam or combinations thereof, which comprises:

inserting into said production tubing an injection tube having an outside diameter of from 1 to 20 percent of the inside diameter of said production tubing;

introducing a sufficient length of said injection tube into said production tubing to contact the bottom of said well and to spiral within said production tubing in helical contact with the tubing wall; and

injecting a scale inhibitor into said injection tube while simultaneously producing from said well.

5. A method of treating a steam recovery well having an open-ended production tubing and penetrating a subterranean geothermal formation and traversing at least one steam bearing zone, which comprises:

inserting into said production tubing an injection tube having an outside diameter of from 1 to 20 percent of the inside diameter of said production tubing;

introducing a sufficient length of said injection tube into said production tubing to contact the bottom of said well and to spiral within in helical contact with the tubing wall; and

injecting a treating fluid into said injection tube while simultaneously producing steam from said well.

6. A method of mounting an injection tube within a recovery well having an open-ended production tubing suspended therein, which comprises:

inserting into said production tubing an injection tube having an outside diameter of from 1 to 20 percent of the inside diameter of said tubing; and

introducing a sufficient length of said injection tube into said production tubing to contact the bottom of said well and to spiral within said production tubing in helical contact with the tubing wall with a helical period of from 10 to 50 times the diameter of said production tubing.

7. The method defined in claim **6** wherein the total weight of said injection tube is measured at the surface during said insertion and a sufficient length of injection tube is introduced into said production to reduce the measured total weight of said injection tube from 80 to 100 percent of the maximum value measured during said insertion.

8. The method defined in claim **6** wherein said helical period is from 7 to 15 feet.

9. The method defined in claim **6** wherein said production tubing terminates at an elevation above the bottom of said well and said injection tube also spirals within the well bore between the bottom of the well and the terminus of said production tubing in helical contact with the well bore wall and having a helical period of from 10 to 50 times the diameter of the well bore.

10. The method defined in claim **6** wherein said recovery well is under a pressure of between about 1,000 and 15,000 psig and wherein an inert gas is continuously injected into said injection tube during said insertion at a pressure equivalent to the pressure within said well.

11. The method defined in claim **10** wherein said injection tube is perforated at selected locations below said production tubing.

12. The method defined in claim **11** wherein said perforations are sealed at the formation surface with a temporary sealant capable of withstanding the pressure within said well and having a sharp melting point at a temperature below the temperature at the bottom of said well.

13. In combination:

a well bore penetrating a subterranean formation and having an open-ended production tubing suspended therein and terminating above the bottom of said well; and

an injection tube within said production tubing and having an outside diameter of from 1 to 20 percent of the inside diameter of said production tubing, said injection tube contacting the bottom of said well and being in helical contact with the wall of said production tubing and having a helical period from 10 to 50 times the inside diameter of said production tubing.

14. The combination defined in claim **13** wherein said injection tube is in helical contact with the wall of the well bore between the well bottom and production tube with a helical period of from **10** to **50** times the diameter of said well bore.

15. The combination defined in claim **13** wherein said injection tube is made of a material having a yield strength greater than 50,000 pounds per square inch.

16. The combination defined in claim **13** wherein said injection tube is perforated at selected well bore elevations below said production tubing.

17. In combination:

a well bore penetrating a subterranean formation having at least one permeable zone containing steam, petroleum oil or hydrocarbon gas;

a production tubing suspended in said well bore and terminating above said permeable zone; and

a perforated injection tube within said production tubing having an outside diameter from 1 to 20 percent of the inside diameter of said production tubing in helical contact with the wall of said production tubing and said well bore below the terminus of said petroleum tubing, said injection tube having a helical period in said production tubing of from 7 to 15 feet and in said well bore of from 5 to 10 feet, said perforations being located at an elevation adjacent said permeable zone.

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