

United States Patent [19][11] **3,743,017****Fast et al.**[45] **July 3, 1973****[54] USE OF FLUIDIC PRESSURE
FLUCTUATION GENERATOR TO
STIMULATE UNDERGROUND
FORMATIONS**

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[51] Int. Cl. **E21b 43/25, E21b 43/26, E21b 43/27**

[58] Field of Search **166/249, 250, 305 R, 166/307, 308, 311, 312, 177**

[56]

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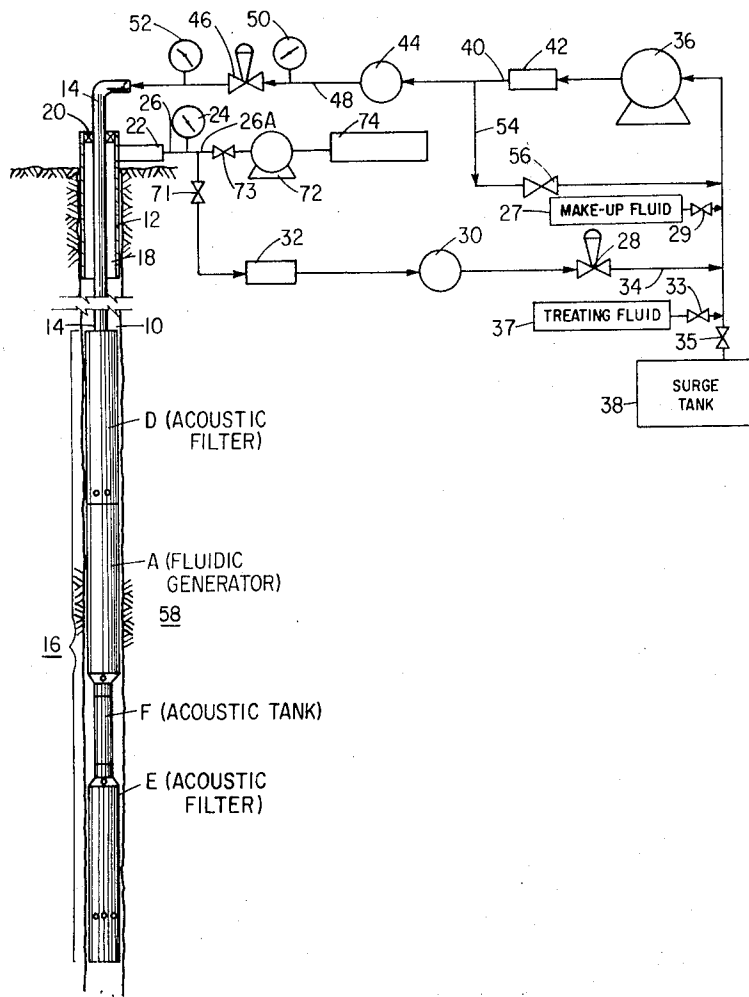
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ABSTRACT

This invention concerns the use of a fluidic pressure fluctuation generator in a well bore to stimulate a sub-surface formation. The generator is connected to the lower end of a string of tubing or drill pipe and is suspended in a well bore adjacent the formation interval to be stimulated or fractured. A fluid is pumped down the tubing string and through the fluidic generator and returned to the surface through the annulus between the tubing string and the wall of the well bore. A back-pressure is held at the surface on the returning fluid such that the hydrostatic pressure P_h of the fluid in the well bore at any level is less than the hydraulic fracturing pressure but sufficiently great so that P_h plus the maximum pressure increase P_m caused by said fluidic pressure fluctuation generator is sufficient to fracture the formation. Other formation stimulation methods are also described.

12 Claims, 3 Drawing Figures



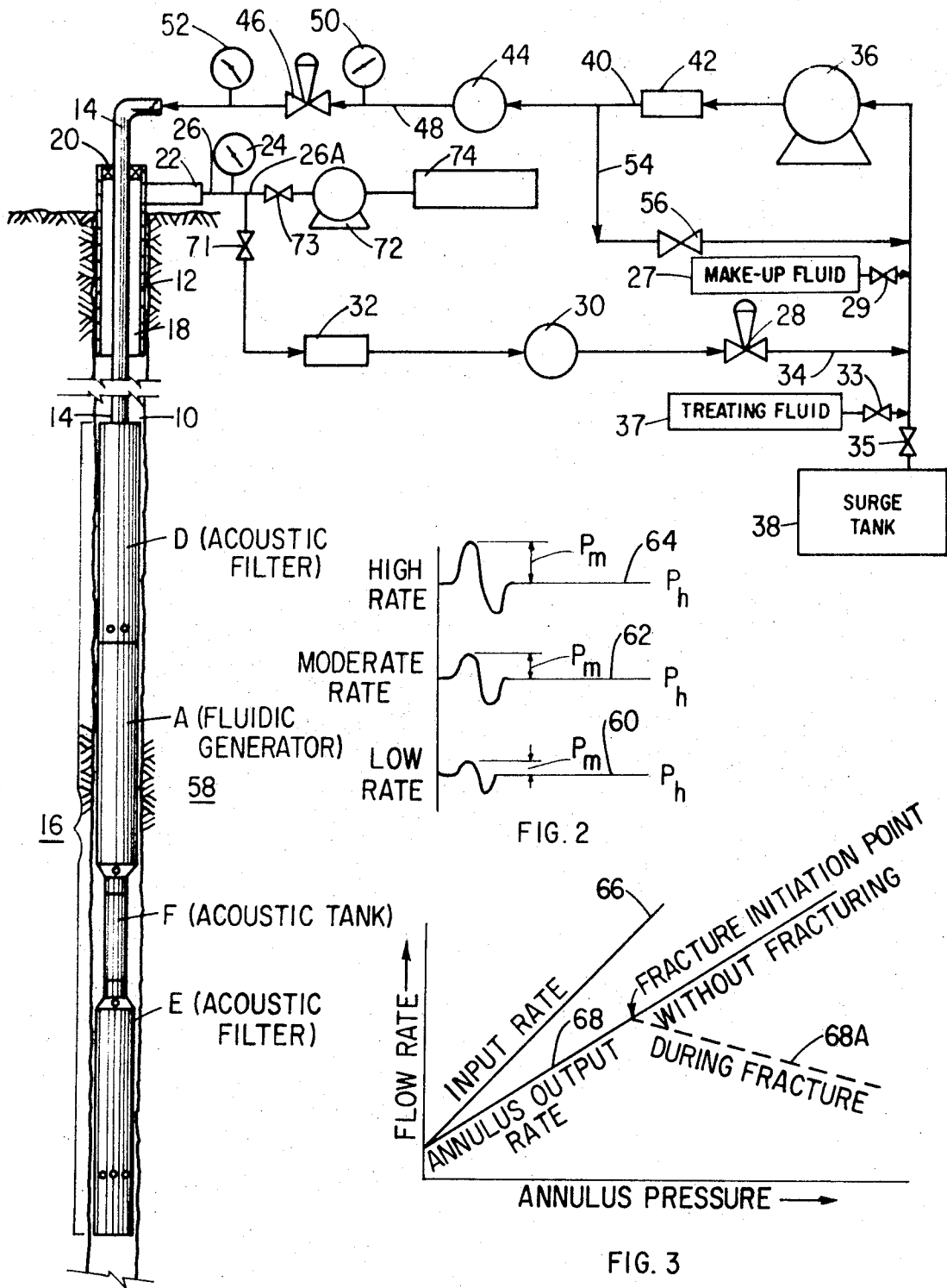


FIG. 1

FIG. 2

FIG. 3

USE OF FLUIDIC PRESSURE FLUCTUATION GENERATOR TO STIMULATE UNDERGROUND FORMATIONS

BACKGROUND OF THE INVENTION

Field of the Invention

This invention relates to stimulating an underground formation penetrated by a well bore and especially relates to the fracturing of the formation at a selected controlled interval.

Setting of the Invention

Many oil and gas wells are drilled into formations that are considered tight, i.e., the formation has low permeability and is reluctant to give up its fluid. The development of the hydraulic fracturing techniques, which started in the late 1940's, is considered to be the outstanding development toward obtaining more oil and gas from such low permeability tight reservoirs or injecting fluids into them. The hydraulic fracturing technique broadly includes injecting a special type fracturing fluid into the formation at a rate and under sufficient pressure so as to cause the formation to crack. The hydraulic fracturing fluid may also carry propping agents which are left in these cracks so that the cracks will not close when the pressure is relieved. Although the hydraulic fracturing technique is developed to a high degree, there still remains some problem areas. One of these is the creation of a fracture at a selected interval. This can be done in some cases with present fracturing techniques, but usually involves the use of several isolating packers. This present invention teaches a novel way of obtaining hydraulic fractures and also shows how the fracture can be isolated to a selected interval.

SUMMARY OF THE INVENTION

This invention concerns the use of a fluidic pressure fluctuation generator in a well bore to stimulate a sub-surface formation. The generator is connected to the lower end of a string of tubing and is suspended in a well bore adjacent the formation interval to be stimulated or fractured. A fluid is pumped down the tubing string and through the fluidic generator and returned to the surface through the annulus between the tubing string and the wall of the well bore. A backpressure is held at the surface on the returning fluid such that the hydrostatic pressure P_h of the fluid in the well bore at any level is less than the hydraulic fracturing pressure but sufficiently great so that P_h plus the maximum pressure increase P_m caused by said fluidic pressure fluctuation generator is sufficient to fracture the formation.

After we have fractured at one interval, we can fracture at another interval simply by stopping the pumping of fluid through the generator, raising or lowering the fluidic pressure fluctuation generator to the desired level in the well bore and starting the pumping of fluid again through the system. We further control the amount of fracturing we do at any elevation by limiting the amount of fluid we circulate after fracturing is initiated, which is indicated at the surface by a sharp drop in flow rate from the annular space. We can also inject special formation treating fluid.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 illustrates a flow schematic of the preferred well hookup for carrying out our invention.

FIG. 2 illustrates pressure variations in the well annulus opposite the fluidic pressure fluctuation generator for a constant annulus backpressure but with different flow rates through the fluidic vibration generator.

FIG. 3 illustrates showing an input and output rate for the annulus pressure.

DETAILED DESCRIPTION OF THE INVENTION

Attention is first directed to FIG. 1 which shows in schematic form the well bore hookup for use in practicing our invention to fracture an underground formation. Shown therein is a well bore 10 which is shown as having a casing 12 at the upper end and an open hole at the lower end. A tubing string 14 having a fluidic pressure fluctuation generator unit 16 connected to the lower end is suspended in the well bore. This includes fluidic generator A, upper acoustic filter D, lower acoustic filter E, and acoustic tank F. A suitable fluidic pressure fluctuation generator unit is shown in U.S. Pat. No. 3,405,770, issued to Edward M. Galle and Henry B. Woods, and in U.S. Pat. No. 3,520,362, issued to Edward M. Galle, both patents assigned to Hughes Tool Company, Houston, Texas.

The upper end of annulus 18 between tubing 14 and casing 12 is closed by sealing means 20 through which the tubing string 14 extends. Annulus 18 has an outlet 22 at the surface connected to line 26. Line 26 connects to branch 26A having valve 73 which connects to pump 72 having source 74. The purpose of branch 26A and pump 72 will be described later.

Line 26 has a valve 71 which, as will be explained later, is open except when pump 72 is operated. Valve 73 is closed except when pump 72 is in use. A pressure gauge 24 is connected into the line adjacent outlet 22. Also connected into the outlet line 26 is a regulating valve 28. This valve 28 is used to maintain a selected backpressure in annulus 18. Valve 28 can be either hand controlled, or it can be controlled automatically. Valve 28 can be a type which automatically holds a selected backpressure on the input side. Suitable valves are shown in U.S. Pat. No. 3,508,577 and in U.S. Pat. No. 3,354,970. A meter 30 and protecting strainer 32 are also provided in output line 26. Thus, by properly setting valve 28 we can control the backpressure of the fluid in annulus 18 during operation of this device.

The output from valve 28 is connected through line 34 to pump 36. A surge tank 38 is also connected into line 34 in conformance with good engineering practices. Make-up fluid can be obtained from source 27 which is connected to the inlet of pump 36 through valve 29. The output of pump 36 is connected through line 40 having strainer 42 to a meter 44. A valve 46 which can be identical to valve 28 is connected into a line 48 downstream of meter 44. Pressure gauges 50 and 52 are provided on either side of flow control valve 46. Line 48 is the fluid injection line which is connected into the upper end of tubing string 14. We also provide a fluid bypass line 54 having control valve 56 which connects from the downstream side to the upstream side of pump 36. Valve 56 functions to permit bypassing a portion of the fluid output from pump 36, should this be desirable or necessary to control the rate of flow into the well.

We shall now briefly describe the operation of the system of FIG. 1. We lower fluidic pressure fluctuation generator unit 16 to be at the level of interval 58 which has been selected to be fractured. We then start inject-

ing a fluid down tubing 14. This fluid can be any suitable fracturing fluid and can even be water. Fluidic pressure fluctuation generator 16 is capable of generating oscillating (alternating current type, or AC) pressure in the interval in the well bore at the same level as it is placed (for a further description of how the patent of Galle et al tool operates, reference is made to said U.S. Pat. No. 3,520,362). The maximum positive AC pressure or positive pressure peaks can be identified as P_m and is illustrated in FIG. 2. Ordinarily, the pressure P_m is a function of the pressure drop through generator 16 which also is a function of the rate of flow through the system. For different flow rates one can accurately predict the pressure drop through a particular tool and thus also predict P_m .

If we know the density of the circulating fluid and the backpressure held on it we can determine the hydrostatic pressure P_h at any given depth. We maintain a backpressure with valve 28 such that the hydrostatic pressure at any level caused by the fluid of column in the well bore and the backpressure is less than the probable fracturing pressure for any interval in the well bore. However, we do maintain the hydrostatic pressure sufficiently high so that when it is added to the pressure P_m developed by generator 16 the resulting pressure is sufficiently high to fracture the interval. One unique, desirable aspect about this system is that the pressure in the well bore is raised above the fracturing pressure only at the interval immediately adjacent the fluidic generator and between acoustic filters D and E. As explained in U.S. Pat. No. 3,520,362, the AC pressure is isolated to this interval. Thus the isolated interval of tool 16 is the only interval fractured. We ordinarily limit the extent of this fracture by limiting the flow of fluid through the system after fracture initiation has occurred. An indication of fracture initiation can be detected when the output rate through meter 30 is abruptly reduced. We like to limit the vertical extent of our fracture. This is often possible by limiting the amount of fluid which we inject after fracture initiation to between about 5 and about 20 barrels, for example. This is especially important if the formation 58 (which is being fractured) is adjacent to an aquifer, as we do not wish any fracture to reach the water-bearing formation.

Evaluation tests of this technique were conducted at Amoco Production Company's Bird Creek test site, Tulsa County, Oklahoma. The well was drilled into the Oologah Limestone, which is located near the surface. This particular Oologah Limestone formation has been utilized in evaluating many different hydraulic fracturing techniques. This is possible because the Oologah Limestone here reacts very much like rocks in deep wells to hydraulic fracturing, acidizing and the like. In one test a well bore was drilled into the Oologah Limestone to a total depth of about 90 feet. Before the test was initiated the well bore was inspected with a television camera and pressure tested with water to 400 psi. In one initial test, the formation was inadvertently broken down by a pressure surge which occurred when the tool started to oscillate. This was a result of having improper backpressure control which permitted the hydrostatic pressure to exceed the formation fracturing pressure throughout the exposed portion of the formation. The well was repaired by squeeze cementing and the well bore was then examined by television camera and by pressure tests to assure that there were no frac-

tures in the well bore wall. A subsequent test was conducted which is now reported. The diameter of the borehole was 7½ inches and the size of the tubing used was 2½ inches OD. During this test the circulating fluid used was water. We used a fluidic generation unit as described above which had a maximum diameter of 7½ inches and had 23½ feet between acoustic filters D and E. During maximum oscillation, the injection rate through the system was 120 gallons per minute. A backpressure of 380 psi was held on the annulus by valve 28. During this time the pressure in the well bore opposite tool 16 was oscillating at about 160 cycles per second from 0-750 psi. The pressure drop across tool 16 during this maximum oscillation was approximately 2300 psi. The maximum pressure peak of 750 psi was isolated to the portion of the well bore adjacent fluidic generator 58. Acoustic tank F was about 20 inches in vertical length. The maximum and minimum pressure for the generator used in the isolated portion of the borehole is equal to P_h + or - one-half maximum pressure variation. During this test the depth of the top of tank F was at about 69 feet in the well bore. Upon the injection of 120 gallons per minute with the backpressure at 380 psi the formation fractured. A horizontal fracture approximately one inch wide was made at a depth of 65 feet in the zone where the oscillating pressure was effected. Although there were no propping agents in the fracturing fluid, this horizontal fracture was propped with small rock fragments that were apparently broken from the fracture faces. A vertical fracture extending from a depth of about 32 feet to about 62 feet was also induced. These fractures were detected by inspection of the bore with a downhole television camera. The vertical fracture was apparently induced first at a lower pressure than that required for the horizontal fracture which was initiated during the latter stages of injection when the flow rate through the fluidic oscillator was highest and when the P_m pressure was at a maximum.

As mentioned above, for a constant annulus backpressure, the peak AC pressure P_m is a function of the rate of flow through the tool. As an example, attention is directed to FIG. 2 wherein we held a backpressure on the annulus of 300 psi and the backpressure was a direct function of the flow rate. In curve 60 with a low flow rate of 60 GPM (gallons per minute) the generated pressure P_m was about 200 psi; curve 62 has a pressure P_m of 300 psi for an intermediate rate of 90 GPM; curve 64 illustrates a pressure P_m of 380 psi for a high rate of 120 GPM.

FIG. 3 merely illustrates how one can tell at the surface when a fracture has been initiated. In FIG. 3 the abscissa is annulus pressure and the ordinate is rate of flow. Assume an input rate of lineal increase as indicated by curve 66. The output rate, before fracturing, is also typically a constant lineal increase of lesser rate because of loss of fluid to the formation as indicated by curve 68. However, the instant that rate and pressure have been increased to the point where the fracture occurs, the output rate takes a sudden and sharp decrease as illustrated by curve 68A. Thus, by merely plotting the input rate and the output rate versus the annulus pressure, one can detect the instant of fracture.

An alternative application of the tool for fracturing is to position the tool at the desired fracture initiation point and first initiate a fracture with the appropriate combination of hydrostatic P_h and maximum P_m .

pressure. The total pressure ($P_h + P_m$) is then reduced to below the fracturing pressure. Valve 71 is closed and valve 73 opened. We then use pump 72 to inject a fracturing fluid from source 74 down the annulus at the fracture treating or fracture opening pressure, which is lower than the fracture initiation pressure. This can be done by either no flow through the tool or with flow of a fluid through the tool and flow of either the same fluid or a different fluid down the annulus.

We can use the system described in connection with FIG. 1 for stimulating subsurface formations in ways other than by fracturing. For example, we can inject other stimulating fluids such as acids, water block removal solutions, scale removal liquids, and the like. When using these particular types of fluids we ordinarily will wish to avoid fracturing. It is usually desired that these fluids be injected in only a particular interval of the well bore. This objective can be accomplished with our system. For example, we determine the interval at which we wish to treat. Then we position fluidic generator A at that level. We start injecting a liquid through the system. We next inject a slug of treating fluid from source 37 through pump 36 after closing valve 35 and opening valve 33. The fill-up volume of the system from fluidic generator A to the top of tubing 14 is known. When sufficient treating fluid is pumped into tubing 14 to completely fill it above the fluidic pressure fluctuation generator, we immediately increase the pump rate so that there is a sudden buildup of pressure P_h in acoustic tank F so that the treating fluid is forced into formation 58. By continuing measuring the output from annulus 18 we can quickly determine the rate and amount of fluid being injected into the formation 58. We keep the total pressure of $P_m + P_h$ below the fracturing pressure.

In a preferred system of operation of the use of this system for injecting stimulating fluids (other than fracturing) we circulate at a relatively low rate in an attempt to get a constant return from annulus 18 through outlet 22. We inject our slug of treating fluid at an increased rate, e.g., $1\frac{1}{2}$ to 3 times, but maintain the constant backpressure with valve 28. We are then reasonably certain that any additional loss of fluid caused by the increased pressure of the fluidic generator A is caused by the stimulating fluid being forced into formation 58 as selected. By loss of fluid we mean the difference between the input rate into tubing 14 and the output rate to outlet 22. In the absence of fluidic generator A, this fluid loss is largely determined by the hydrostatic pressure in the borehole which is at least partially controlled by the amount of backpressure held thereon. After sufficient stimulating fluid has been injected, we can then inject, if needed, an inert cleaning fluid through the system.

While the above invention has been described with considerable detail, it is possible to make many modifications thereof without departing from the spirit or the scope of the invention.

We claim:

1. A method of fracturing a selected formation penetrated by a well bore which comprises the steps of:
 - pumping a fracturing fluid down said well bore through a tubing string;
 - converting a portion of the energy of said fracturing fluid into acoustical vibrations at a level adjacent said formation to be fractured to cause positive pressure variations of P_m ;

transmitting said acoustic vibrations to the fluid in the well bore adjacent the formation to be fractured;

returning said fracturing fluid to the surface through the annular space external of said tubing string; holding a backpressure at the surface on the returning fluid in the annulus such that the hydrostatic pressure P_h of the fluid in the well bore at the level of said formation is less than the hydraulic fracturing pressure but sufficiently great so that P_m plus P_h is sufficient to fracture said formation.

2. A method as defined in claim 1 including the step of pumping a slug of formation treating fluid down said tubing string so that at least a portion of said treating fluid is injected into said formation by the combination of pressures of P_m and P_h .

3. A method as defined in claim 1 including the steps of:

reducing the rate of pumping of fracturing fluid through said tubing string so that P_m plus P_h is now less than the pressure required to fracture the formation;

stopping the return of fracturing fluid to the surface through the annular space and thereafter injecting a fracturing fluid down the annulus at a pressure below the fracture initiation pressure but above the fracture opening pressure.

4. A method as defined in claim 3 which includes the step of adding propping agents to the fracturing fluid injected down the annulus.

5. A method of fracturing a selected formation penetrated by a well bore which comprises the steps of:

pumping a fluid down a tubing string suspended in said well bore;

converting a portion of the energy of said circulating fluid into acoustical vibrations by means of a fluidic pressure fluctuation generator suspended in the well bore adjacent said selected formation;

transmitting said acoustic vibrations from the fluidic pressure fluctuation generator to the fluid in the well bore at the level of the selected formation so that said fluid at said level has a positive pressure variation peak of P_m ;

acoustically isolating the acoustic vibrations to the region in the well bore adjacent said selected formation;

returning said circulating fluid to the surface through an annular space exterior of the tubing string;

maintaining a backpressure on the returning circulating fluid, said backpressure being limited such that the hydrostatic pressure in the well bore at any level is less than the formation breakdown pressure to which the fluid is exposed but in which P_m plus the hydrostatic pressure in the well bore adjacent the selected formation exceeds its fracturing pressure so that said selected formation is fractured.

6. A method as defined in claim 5 which includes pumping the fluid down the tubing string at a constant rate, holding a constant backpressure on the returning circulating fluid, measuring the flow of fluid from the annular space and pumping not over about 20 barrels of circulating fluid down said tubing string after a sharp drop in flow rate from the annular space occurs.

7. A method as defined in claim 6 including the step of moving said fluidic vibration generator to the level of a second formation to be fractured and thereafter repeating the method defined in claim 5.

8. A method as defined in claim 5 in which the amount of fluid injected after the sharp drop in rate of fluid flow from the said annular space is in the range of 5-20 barrels.

9. A method of stimulating a selected formation penetrated by a well bore which comprises the steps of:

positioning a fluidic pressure fluctuation generator at the lower end of a tubing string in the well bore adjacent the formation to be treated;

pumping a fluid down said tubing string to convert a portion of the energy of said fluid into pressure vibrations by means of said generator having a positive pressure variation peak of P_m ;

acoustically isolating the pressure vibrations to the region in the well bore adjacent said selected formation;

returning said fluid to the surface through the annular space external of said tubing string;

holding a backpressure at the surface on said returning fluid, said backpressure being such that the hydrostatic pressure P_h at any level is less than the fracturing pressure;

drostatic pressure P_h at any level is less than the fracturing pressure;

injecting a slug of formation treating fluid down said tubing string through said generator so that the pressure P_m generated by the said generator drives a portion of said treating fluid into said formation.

10. A method as defined in claim 9 in which the sum of the pressures P_m and P_h is below the fracturing pressure of the formation.

11. A method as defined in claim 9 in which sufficient formation treating fluid is injected to fill the tubing string from the surface to the said generator and then suddenly increasing the injection rate of fluid into said tubing string so that there is a sudden buildup of pressure P_h .

12. A method as defined in claim 9 in which a constant backpressure is held throughout the treatment and then injecting the treating fluid at an increased rate over the prior injection rate of the prior fluid.

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