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METHOD OF FRACTURING FORMATIONS IN A WELL

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ABSTRACT OF THE DISCLOSURE

The method of fracturing a sub-terranean formation adjacent a well bore having a casing therein. It is considered an improvement over the so called "limited entry" method of fracturing formations. The method contemplates the use of ball sealers to insure that a satisfactory number of perforations are open prior to fracturing, the use of a low perforation differential pressure to insure simultaneous, effective stimulation of pay zones having substantially the same fracturing pressure, and, in some instances, the use of plug means to isolate zones having significantly different fracturing pressures and the subsequent treating of these different zones.

This invention relates to a method of fracturing a subterranean formation adjacent a well bore having a casing therein. More particularly, the invention relates to a method of fracturing a formation which is considered an improvement over the so called "limited entry" method of formation fracturing.

The fracturing of multiple pay zones with conventional techniques (densely perforated zones, treatment control through the use of bridge plugs or ball sealers) can result in expensive or marginal completions. Fracturing the Dakota formation in the San Juan Basin of New Mexico, for example, with conventional methods offers few exceptions to the above.

The Dakota formation in the San Juan Basin is approximately 200 to 300 feet thick. It often is composed of multiple, hard, low porosity, gas bearing sands separated by shale. The lower Dakota is composed of a series of sands of approximately equal fracturing pressures. These pressures often vary markedly between locations. The middle and upper Dakota sands are less numerous. They have approximately equal fracturing pressures which are significantly different from the lower sands. The fracturing pressures of the middle and upper sands also can vary over a short distance. The fracturing pressures of all the Dakota sands are difficult to quantitatively predict.

The Dakota is frequently sand-water fractured with conventional multi-stage treatments, employing bridge plugs or ball sealers for treatment control and diversion. Normally the amount of propping agent used is between 50,000 and 100,000 pounds of sand. Treating rates usually are between 35 and 50 barrels per minute. In many cases individual sands will be perforated with so many holes that the treatment will be accepted into the individual sand that has the lowest fracturing pressure.

Usually ball sealers are used during application of the fracturing fluid in a conventional treatment in an attempt to open additional perforations and/or divert the fracturing fluid. However, ball sealer performance has not proven reliable for this purpose. Ball sealer leakage, communication behind the casing between closely spaced perforations, and maintenance of an effective seal on upper perforations in small diameter casing due to the bypass of fluid and additional balls, could contribute to poor ball sealer performance. The use of ball sealers

during a Dakota treatment is complicated further by the treating pressures necessary to: (1) achieve breakdown of additional pays, (2) open additional perforations, and (3) achieve sufficient rates to prevent sand-outs and effectively stimulate the Dakota sands. Usually such pressures are near the maximum safe internal yield pressure of the casing.

Other problems often associated with the conventional Dakota fracturing techniques are poor treatment coverage, sand-outs, low fracturing rates at high treating pressures, excessive hydraulic horsepower usage and the associated extra costs. In general, poor treatment coverage can be attributable to: (1) an excessive number of perforations, (2) undependable ball sealer performance for treatment diversion, or (3) the other problems associated with the use of balls. All of the above problems can occur when an excessive pressure drop exists across the open perforations as a result of poor perforating efficiency, in which case, the fracturing rate will be restricted because of a high surface treating pressure.

There was a need for a method of fracturing such formation which would meet the following objectives:

(1) Effectively stimulate all reservoir beds.
(2) Obtain maximum productivity.
(3) Produce maximum reserves.
(4) Eliminate or reduce remedial operations.
(5) Accomplish these objectives at reasonable cost.

Several prior art methods have been developed in an attempt to solve the foregoing problems, but none have been entirely satisfactory.

The use of ball sealers is not fully satisfactory for reasons discussed previously. The limited entry method employs a limited number of perforations to provide a certain pressure drop across the perforations (perforation differential) at a designed treating rate. The perforation differential is designed to be sufficiently high to cause the bottom hole treating pressure to exceed the various fracturing pressures of the perforated zones, in which case, the zones will be effectively treated—assuming all perforations accept fluid as intended. However, to assure successful application of the technique, the treatment must be designed properly. To do this, the fracturing pressures of the perforated zones must be known. Also, the effectiveness of the simultaneous limited entry treatment of zones of different fracturing pressures becomes more reliable with the employment of high perforation differentials (1000+p.s.i.). Limited entry per se, is not justifiable for effective stimulation of the various Dakota pays for several reasons. One is the high perforation differential which increases the reliability of the technique. High perforation differentials and the associated high treating pressures could necessitate an increase in casing costs and hydraulic horsepower requirements. Also, the accurate design of such a treatment, particularly necessary if lower perforation differentials are employed, is difficult because of the significant and unpredictable variation of the fracturing pressures of the various Dakota zones. Finally, limited entry treatment of an extensive group of pays, as usually found in the Dakota, can result in low rates into an individual pay with a corresponding reduction in fracture extension or a sand-out.

The third method, known as staging, employs a bridge plug for separate treatment of each isolated zone. The treatment of each isolated zone is a stage. The use of this method exclusively is not practical because of the number of stages necessary for effective treatment of the usually numerous Dakota pays.

Documents which generally represent the state of the prior art include:

(1) Millheim, Kieth and Cichowicz, Leo, "Testing and Analyzing Low Permeability Fractured Gas Wells," SPE

Paper No. 1768, presented at SPE Rocky Mtn. Regional Meeting, Casper, Wyoming, May 22–23, 1967.

(2) Webster, K. R., Goins W. C. Jr., Berry S. C., "A Continuous Multistage Fracturing Technique," Jour. Pet. Tech. June, 1965, pp. 619–625.

(3) Lagrone, K. W., Rassmussen, J. W., "A New Development in Completion Methods—Limited Entry Technique," Jour. Pet. Tech. July, 1963, pp. 695–702.

(4) Halliburton Company, Technical Report, "Limited Entry for Hydraulic Fracturing," Bulletin F-3077, June 1964.

(5) Dowell, "Technical Report, Limited Entry Well Completion Technique," September, 1964.

(6) Dowell, Division of the Dow Chemical Co., "Frac Guide Data Book," 1965.

(7) Western Company, "Engineered Limited Entry," 1964.

The method of this invention arose out of a need to solve the foregoing problems and contemplates:

(1) The employment of a limited number of perforations to provide a low (approximately 250–350 p.s.i.) perforation differential for simultaneous treatment of pays of approximately equal fracturing pressures.

(2) The use of the minimum number of stages necessary (usually two) to separate zones of significantly different fracturing pressures.

(3) The use of acid and balls prior to the actual treatment to open the perforations.

Item (1) above is accomplished through the use of a number of perforations which, when all are open to accept fluid, will provide approximately a 250–350 (preferably 300) p.s.i. perforation differential at the designed treatment rate. This perforation differential is sufficient to insure that all perforations in pays of approximately equal fracturing pressure are accepting fluid at an effective rate. This amount of perforation differential can be obtained at reasonable hydraulic horsepower cost. Treating pressures associated with perforation differentials in the above range do not require special casing, or cause treating rates to be restricted significantly.

The item (2) staging, is sometimes necessary for the effective treatment of zones of significantly different fracturing pressures, using low perforation differentials. This method is used rather than a high perforation differential for reasons given previously. Staging also is incorporated into the method to provide concentration of the treating rate and treatment per zone. This can be necessary for satisfactory rates and fracture extension in the individual pays. As discussed, this can be an advantage over simultaneous limited entry treatment of an extensive group of pays. The number of stages required for effective Dakota treatment coverage is usually two.

Item (3) usually is a necessary step for achieving the designed perforation differential or having a satisfactory number of perforations open to accept fluid. This is because of the low perforating efficiency experienced in the Dakota formation. By insuring that a satisfactory number of perforations are open prior to the actual treatment, effective stimulation of all reservoirs in a given stage is assured. Therefore, there is no dependence on ball sealers during the actual treatment to breakdown zones, open additional perforations and/or divert the treatment.

The cost of performing a treatment according to the method of this invention is approximately the same as that of a conventional treatment of the same size.

METHOD DETAILS

The method of this invention is normally carried out in two phases. The first phase is devoted to fracturing the lower Dakota, typically a series of thin sands separated by shale, with all sands having approximately the same fracturing pressure. Initially the sands justifying stimulation are selected. A number of perforations are chosen which, when all are open to accept fluid, will provide adequate treatment coverage, desired treatment distribution, and a perforation differential of approximately 250–350 (preferably 300) p.s.i. at an acceptable rate. The perforations (usually 15–20) are normally grouped in the most porous sections of the sands to be fractured. Vertical fracturing should result in effective treatment of each zone. The treating rate is governed by the casing pressure limitations, hydraulic horsepower cost, the number of perforations selected and the desired perforation differential. For Dakota fracturing the treating rate necessary to satisfy all conditions usually is between **50** and **55** barrels per minute.

By obtaining the 300 p.s.i. perforation differential at the anticipated pressure and rate all perforations will take fluid and all porous intervals will be stimulated. If a perforation differential in excess of that designed for is obtained, all pays will still be treated if the excess is due to a treating rate higher than anticipated. However, if this is not the case, all perforations probably are not open. Treatment coverage then is proportionally reduced and sand-out as well as other associated problems can occur. Therefore, the treatment should not be started until a sufficient number of the perforations are calculated to be open. A sufficient number of perforations is considered to be enough open perforations to insure satisfactory treatment of all sands in a given stage. As previously mentioned, ball sealers and acid are employed for the purpose of opening the perforations prior to the treatment.

The second phase of the method of this invention, as applied to Dakota stimulation, usually involves the treatment of no more than two separate sands having approximately the same fracturing pressure. These sands normally have a different fracturing pressure than the sands treated by the first stage. For reasons given previously a bridge plug is used for zone isolation. The second stage application is simplified due to a reduced number of sands requiring stimulation. However the design considerations are the same for each stage.

EXAMPLE

For purposes of illustration, an example of the method of this invention will now be set forth in greater detail. The treatment is design and evaluated by using the following equations and the various charts and nomographs included in the "limited entry manuals" of the various service companies, as follows:

Halliburton Company, Technical Report, "Limited Entry for Hydraulic Fracturing," Bulletin F–3077, June 1964
Dowell, "Technical Report, Limited Entry Well Completion Technique," September 1964
Dowell Division of the Dow Chemical Co., "Frac Guide Data Book," 1965
Western Company, "Engineered Limited Entry," 1964

Equations:

$$P_s = ISIP + P_f + P_{pf} \quad (1)$$

where

P_s=surface injection pressure
ISIP=instantaneous shut-in pressure, p.s.i.
P_f=pipe friction, p.s.i.
P_{pf}=perforation friction, or perforation differential, p.s.i.

Also

$$ISIP = BHFP - P_h \quad (2)$$

where

BHFP=bottom hole fracturing pressure
P_h=hydrostatic pressure

In Dakota fracturing in the San Juan Basin, the surface treating pressure, P_s, is limited to approximately 4000 p.s.i., primarily by the 4½ inch J–55 casing which is normally set. Due to economic considerations, this casing is considered standard for these completions. For illustration, there are assumed to be ten individual sands to be treated by the first stage. It is also assumed that 15 perforations will distribute the treatment appropri-

ately. From analogy an ISIP of approximately 1600 p.s.i. for each of the sands is expected. Sand concentration is 1 lb. per gallon of water.

From a service company chart, such as that shown on page 20 of the aforesaid Halliburton Company, Technical Report, it is determined that a rate of 3.6 b.p.m. per perforation will provide a perforation differential of 300 p.s.i. A 0.55 inch perforation diameter and a 0.95 perforation coefficient are assumed. Because 15 perforations have been selected, a total treating rate of 54 b.p.m. is required (3.6 b.p.m. × 15 perfs).

The effect of a propping agent on the treatment design is minor. For purposes of illustration it has been omitted. Actually if the treatment is designed without considering the propping agent, the actual treatment should be more effective than the designed treatment. The sand usually will result in an increase in bottom hole treating pressure without a corresponding increase in surface treating pressure at the designed rate. Also a higher surface treating pressure will occur prior to the actual treatment, while determining the number of perforations open with frac water only. Therefore, consideration must be given to determining the pressures to be expected without the sand.

The use of a relatively high (0.95) perforation coefficient in treatment design usually results in the calculation of the maximum treating rate (thus surface pressure) necessary to treat a given number of perforations at a desired perforation differential. If the perforation coefficient used in the design is less than actual, the calculated treating rate will not produce the desired perforation differential.

From service company friction charts, such as that contained in the aforesaid Dowell Division of Dow Chemical Co., "Frac Guide Data Book," pipe friction, assuming a 6000 foot completion, is determined to be approximately 1750 p.s.i. This is based on fresh water containing 2.5 lbs. of synthetic polymer friction reducer per 1000 gallons and a rate of 54 b.p.m.

Substitution into Equation 1 above results in a calculated surface treating pressure of 3650 p.s.i. This is within the casing pressure limitations. Therefore the diameter and number of selected perforations and the calculated treating rate are satisfactory. If the surface treating pressure had been above 4000 p.s.i., the maximum safe internal yield pressure of the casing, the diameter or number of perforations would be modified to result in a satisfactory surface treating pressure and fracturing rate. Additional friction reducer also could be used. A perforation differential of approximately 300 p.s.i. would be maintained. A satisfactory number of perforations to provide adequate treatment coverage would be retained. If this were impossible, a second stage would be employed.

PERFORATING

Correct perforating plays an important role in the successful application of the technique. Because a relatively small number of perforations are employed, it is necessary and basic to the application of the method to have all perforations, or at least a majority, open to accept fluid prior to pumping sand. This is accomplished in two ways. The use of the best perforating charges available for this type completion is recommended. Second, the use of acid and ball sealers helps to insure that a sufficient number of perforations are open to accept fluid, as is discussed in greater detail hereinafter. Thus, for the most successful jobs, in terms of average productivity increases above that of offset completions, were those done with at least 80 percent of the total perforations calculated open to accept fluid. Two completions utilizing this invention were perforated with bullets (0.63" hole size) and another was perforated with a burr free shaped charge (0.57" hole size). These wells and most of the other successful completions where a high percentage of the holes were open prior to fracturing were perforated with cased carrier charges designed to create hole sizes greater than 0.55" in diameter.

Good ball sealing action is important for opening all perforations prior to the actual treatment. Therefore, the burr free characteristics and consistent hole sizes obtained with cased carrier charges is also important. The consistency of the hole size obtained with these charges also contributes to the reliable calculations of the number of perforations open.

In addition to the above, larger perforation holes are normally preferred because fewer perforations are necessary to provide the desired perforation differential. The result of fewer holes is that fewer balls are needed; the number of holes to be opened is reduced; the treatment is concentrated; the possibility of ball sealer leakage is reduced and application of the technique is simplified. For these reasons, the cased carrier, large hole, burr free type perforating charge is preferred.

APPLICATION

The following is the presently preferred procedure followed for the application of the method of this invention.

First stage procedure

(1) Displace the bore hole with frac water and spot HCl acid across interval to be perforated. This step initially lowers pipe friction and facilitates breakdown. (This step may not be required in all instances, although it is preferred.)

(2) Perforate a section of the casing as described above.

(3) Run tubing with full opening retrievable packer into the casing. The tubing and packer permit better control of acid as used in step 4 and maximum pressures in step 5, but may not be required in all situations.

(4) After setting the packer above the perforated interval, if a packer is used, matrix acidize with mud acid. Matrix acidizing is used to facilitate the opening of additional perforations by ball sealers, step 5. It is done at low rates and pressure to prevent premature fracturing prior to maximum perforation coverage, and, hence, is carried out at pressures less than the formation fracturing pressure.

(5) Drop nylon core rubber covered balls in groups of two or three with a frac water spacer between each group. Drop balls until perfs ball off at the maximum safe tubing pressure. Hold this pressure on the tubing to allow additional perforations to open. If this occurs, reball off to the above pressure until no further pressure breaks occur. (If ball off occurs before the number of balls equal to the number of perforations have reached the perforated interval and no additional break is seen, it may be necessary to drop balls in an acid spacer to facilitate additional breakdown.) Knock off balls by lowering packer through perforations. Alternatively, balls may be removed by releasing pressure on the fluid in the well, thereafter, the tubing and packer are removed from the well.

Significant pressure breaks (perforations opened) have been observed to occur above 5000 p.s.i. Therefore, packer, tubing and maximum pressures are believed desirable for optimum success. Holding pressure and reballing off is done to insure the maximum number of perforations are open and will accept fluid. The nylon core diameter of the ball sealers must exceed that of the perforations. Attempting this step down casing has not proven satisfactory for the multiple pay lower Dakota (first stage). Leave HCl acid spotted across the perforations and pull out of the hole. HCl left over the perforations should prevent observed plugging of perfs (by undissolved solids) prior to fracturing.

(7) Using frac water only, obtain a maximum stabilized rate and pressure for one minute. Shut down. Read

ISIP. Calculate the perforation differential and thus the number of perforations taking fluid. If the designed parameters are obtained or if a majority of the perforations are taking fluid, so that adequate treatment coverage and a trouble free stage can be expected, proceed with the treatment by pumping the fracturing fluid into the formation through the perforations at a rate and pressure level to give a perforation pressure differential in the range of 250–350 (preferably about 300) p.s.i. and until the formation is fractured.

A maximum stabilized rate and pressure should be obtained, prior to the actual fracturing operation, for approximately one minute to insure that no further breakdown is occurring and that the ISIP is obtained under consistent conditions.

Second stage procedure

If a second stage is required, then the following additional steps will be performed:

(1) Set a bridge plug so as to isolate the additional section of the casing to be perforated.

(2) Perforate as above described.

(3) Establish a maximum stabilized rate and pressure by pumping down the casing using frac water for one minute. Obtain the ISIP. Calculate the perforations open. If the design parameters are satisfactorily met, proceed with the treatment.

Because of the generally lower fracturing pressure, the smaller number and increased porosity of the upper Dakota sands, fewer perforation opening problems are encountered. This and the increase in costs associated with the use of the tubing and packer preclude the running of same. If necessary, acid and/or balls are pumped down the casing during the second stage as previously described under step 5 of the first stage. However, because balls are used through the casing, the associated pressures necessarily will be lower.

This invention contemplates having a satisfactory number of the perforations open to accept the fracturing fluid prior to pumping sand. By doing so, adequate treatment coverage is virtually assured. There is no dependence on ball sealer action during the actual fracturing treatment.

RESULTS

For the purpose of evaluating the results of the method of this invention, initial Dakota well productivity (in terms of absolute open flow potential, AOF) was compared to the average of the conventionally treated offset Dakota wells.

One application of the invention was made on the last three wells of an eight well Dakota program at the Angel's Peak Area, located in the central portion of the San Juan Basin. The three wells had an average AOF of 16,900 m.c.f. per day. This is an 89 percent increase in AOF over the average of the nine offset wells. The average AOF of the remaining five wells in the program completed with conventional two stage treatments was only 29 percent higher than that of the 15 offset completions.

Another area of application of the method of this invention was in Blanco Canyon. In this area, approximately six miles east of Angel's Peak Area, an eleven well Dakota development program was conducted. Three of the wells completed using the described method were very successful jobs in that over 80 percent of the total perforations were calculated to be open. The remaining wells had a majority of the perforations open prior to treatment, such that all significant pays were definitely known to have been treated. The three most successful completions using the method of this invention had an average AOF 73 percent higher than that of the twelve offset wells. The remaining three completions made in accordance with the invention had a 59 percent increase in average AOF over the eleven offset wells. Overall, the six Blanco Canyon completions with this invention had an average AOF 65 percent higher than the 17 offset wells. Constant rate, pressure drawdown testing of completions made by the method taught herein in the Blanco Canyon Area indicated large effective fracture systems were established in both wells. The testing also indicated significant increases in productivity and recoveries could be expected over conventionally treated wells in the area.

The average Dakota AOF obtained on the nine completions by the use of this invention was 78 percent, or over 4,000 m.c.f.p.d. above that of the offset Dakota wells.

Accordingly, the foregoing invention provides the art with a relatively simple method for fracturing formations and thereby stimulating production. As a result of this invention there has been a substantial elimination of poor treatment coverage, low treating rates, high pressures, and sandouts. Costs of performing the method of this invention are approximately equivalent to those of conventional treatments of the same size. Now multiple pays with approximately equal fracturing pressure can be effectively stimulated with one fracturing stage. As a result, some areas previously considered uneconomical can now be considered for development.

Further modifications may be made in the invention as particularly described without departing from the scope thereof. Accordingly, the foregoing description is to be considered as illustratively only and is not to be considered as a limitation on the invention as to be described in the following claims.

What is claimed is:

1. The method of fracturing a sub-terranean formation adjact a well bore having casing therein, said method comprising the steps of:
   - perforating a first section of said casing adjacent portions of said formation having similar fracturing pressures;
   - pumping an acid liquid into said first section of said casing at a pressure less than formation fracturing pressure;
   - dropping ball perforation sealers into said first section of said casing while pumping a liquid into said casing until sufficient perforations are sealed and pressure in said casing reaches a predetermined level, which pressure level does not exceed maximum safe working pressure for the well;
   - removing said ball sealers from sealing engagement with said perforations;
   - and pumping hydraulic fracturing fluid into said formation through said perforations in said first section of said casing at a rate and pressure level to give a perforation pressure differential in the range of about 250 p.s.i. to about 350 p.s.i. and until said formation is fractured.

2. The invention as claimed in claim 1 including the additional steps of:
   - perforating another section of said casing vertically spaced apart from said first section;
   - and pumping hydraulic fracturing fluid into said formation through the perforations in said other section of casing at a rate and pressure level to give a perforation pressure differential in the range of about 250 p.s.i. to about 350 p.s.i. and until said formation is fractured adjacent said other section of said casing.

3. The method as claimed in claim 1 including:
   - setting a retrievable packer mounted on a tubing above said first section of said casing between said perforating step and said pumping of said acid liquid;
   - and dropping said ball sealers through said tubing.

4. The invention as claimed in claim 3 including:
   - withdrawing said tubing and packer from said well prior to said pumping of hydraulic fracturing fluid.

5. The invention as claimed in claim 1 wherein:
   - said acid liquid is a mud acid.

6. The method of fracturing a well having a casing therein, comprising the steps of:

spotting an acid liquid across the casing interval to be perforated;

perforating said interval;

running a tubing with full opening retrievable packer into said casing and setting said packer above said interval;

pumping mud acid down through said tubing and through the perforations in said interval;

dropping ball perforation sealers through said tubing while pumping a liquid down said tubing until sufficient perforations are closed and pressure in said interval reaches a predetermined level, which pressure level does not exceed maximum safe working pressure for the well;

removing said ball sealers from sealing engagement with the perforations in said interval;

removing said tubing and packer from said well;

and pumping hydraulic fracturing fluid through the perforations in said interval of said casing and into the formation at a rate and pressure level to give a perforation pressure differential in the range of about 250 p.s.i. to about 350 p.s.i. and until said formation is fractured.

7. The invention as claimed in claim 6 including:

isolating said first interval of said casing and perforating another interval of said casing vertically spaced apart from said first interval;

perforating said second interval;

and pumping hydraulic fracturing fluid through the perforations in said second interval at a rate and pressure level to give a perforation pressure differential in the range of about 250 to 350 p.s.i. and until said formation is fractured again.

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