Production Stimulation—Planning and Operational Techniques

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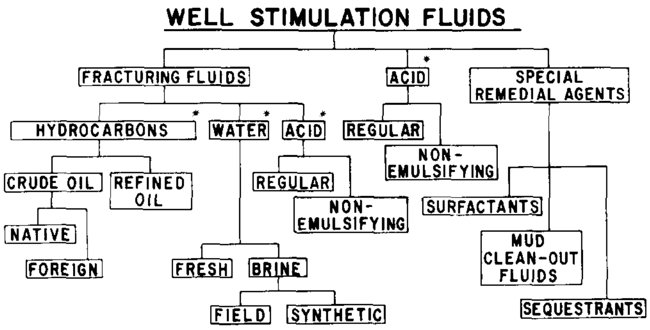
NEED FOR IMPROVEMENT

In the early stages of development of any process which fills a long felt need, there may be a number of improvements or refinements of a major nature if an aggressive research program is maintained. With usage and the adaptation to more applications, the actual magnitude of possible improvements in materials becomes less and less. Stated otherwise, when a process is deemed adequate, successive increments of improvement becomes less important. Such is the case with well stimulation. (Fig. 1)



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It should not be implied that further research or investigation is unjustified. On the contrary, much remains to be done. As long as there are areas that do not respond properly to existing materials and techniques, there is room for improvement. The possibility of a major improvement in present processes is limited. However, there are excellent possibilities for the development of an entirely different approach to the field of well stimulation.

Among the improvements in stimulation that have been recently introduced are:

Acid

A more effective sequestering agent has been found which hinders the posttreatment reprecipitation of iron compounds which may occur naturally or be introduced into a well. This material is applicable to producing oil or gas wells and water injection wells.

Many surfactants have been improved; in some cases new ones have been made available. Some of these are very adaptable to use in fluids for remedial work and fracturing.

Fracturing

Materials to alter the fluid loss characteristics of virtually any of the commonly used stimulation fluids are now available. These are adapted to oils, water and acids.

Explosives

A new approach to a very old stimulation process has been developed. Relatively light charges are lowered into the well on an electrical line. The detonation purportedly causes a surge of fluid which creates limited fractures in close proximity to the drilled hole.

The most practical approach to immediate improvement lies in the more efficient utilization of existing materials, equipment and other facilities. At best, the mechanical efficiency of a stimulation treatment leaves something to be desired. No possibility should be overlooked in an effort to obtain the most for the money and effort expended.

A well (oil, gas, water or water injection) does not possess any useful function until it is adapted to its ultimate use. Since most wells are limited in performance prior to stimulation, it may be assumed that stimulation is most important.

Much may be said about the desirability of designing a well with a view to using a specific stimulation technique. Generally, this may be done without violating any of the accepted drilling and completion practices. Too frequently, there is a tendency to follow the same procedure that was used on the last well without investigating the reasons for that procedure. A well which is properly designed may cost less per unit of ultimate recovery.

FACTORS TO CONSIDER

The first factor to consider when planning stimulation is the formation itself. Porosity, permeability, reservoir pressure and temperature as well as chemical composition and fluid content all have a bearing on how production is to be increased. The fluid and material used and the method of treatment are largely determined from these characteristics. Howard and Fast have presented a theoretical method for using such information to a greater advantage for fracturing type treatments.[1]

If the zone of interest has a high degree of acid solubility, it is normally considered a candidate for an acid base treatment. The desirability of a combination acid-fracture treatment may make it attractive to carry propping agent in unthickened acid or to use a thickened or gelled acid which can carry high ratios of sand.

A potentially productive section which has little or no solubility will usually respond better to a fracture type treatment. The most popular fluid for this type of well is formation crude or refined oil. If well conditions warrant or greater proportions of sand are deemed necessary, the oil may be thickened by emulsifying or gelling.

Choice of Fluid

An alternate possible treating fluid is water. With proper modification, it can be adapted to most formations. It can be used in either the thickened or unthickened form. Water has been used extensively in gas and gas storage areas and to a lesser degree for oil production; this latter usage is increasing. Its original application was to water producing and injection wells.

Although surfactants are usually considered and adjunct or accessory to regular stimulation treatments, some formations will give good response to injection of these reagents in an oil, water or weak acid.

Some of the available fluids have definite temperature limitations. This is particularly true of oil base fluids. Any time elevated formation temperatures are encountered, changes in viscosity may affect the sand-carrying ability of the fluid.

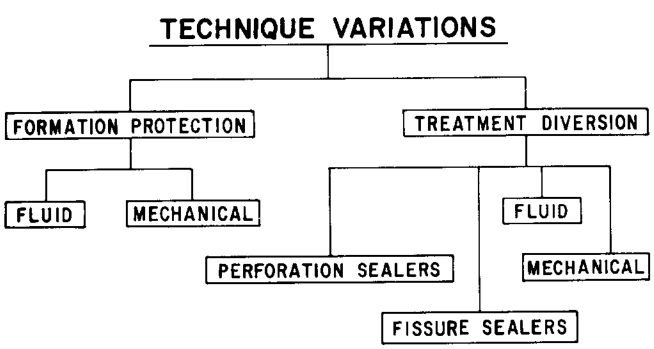
Interference, by either high or low temperature, with breaking or thinning after the treatment is completed may seriously hamper the return of fluids to the well. Internal breakers should be incorporated in thickened fluids which are sensitive to such conditions.

When fracturing was introduced, the ability of a fluid to carry sand was considered to be extremely important because of the low rates of injection. Neglecting specific cases and well conditions, it may now be safely assumed that any of the fluids will carry sand if sufficient linear velocity of injection is maintained. If, due to pressure limitations of well equipment or other conditions, it is not possible to maintain the desired velocity, then a more viscous fluid should be selected.

Compatibility is extremely important in the selection of stimulation fluids. The fluid should be checked by the well owner for its effect on a sample of the formation and also on the native fluids. If it is an acid or thickened fluid, the same verification should be made after reaction or breaking.

The possibility of reprecipitation or release of insoluble particles should not be overlooked. There have been extreme cases in which native crude was so altered by aging that it was no longer compatible with crude still in place. Swelling of clays and formations of emulsions are ever present possibilities. Fortunately, there are additives and surfactants available to aid in alleviating such conditions.

The horseposer expended in getting a stimulation treatment to the bottom of the well may be very great when compared to the "bottom-hole" horsepower necessary to actually inject. An unwise choice of fluids by the well owner can increase the cost of a treatment or can affect the injection rate seriously by increasing the surface pressure because of friction. (Fig. 2). It is possible to



expend more energy on friction than is actually used at the face of the formation. Before the true nature of some of the fluids was known, this was common practice.

There are certain fluids in the non-Newtonian classification which have a very desirable property. The additional surface pressure, due to friction of movement through tubular goods, can be less for the prepared fluid than for base fluid from which it is manufactured. This offers a particular advantage in high velocity treatments and in stimulating deep wells. The advantage is most apparent in smaller tubular goods. Since these fluids have high apparent viscosity, their sand carrying ability is excellent.

The loss of fluid to the natural permeability of the formation must be properly considered. The distance the fracture is extended is dependent on fluid and formation characteristics. The same factors also govern the concentration of sand in the fracture.

Under such conditions, it may be desirable to vary the fluid-loss properties during the treatment. Some fluids have inherently low fluid-loss characteristics. All fluids normally used for stimulating, including water and acid, may be brought within reasonable limits by proper fluid-loss control additives.

When an effort is made to economize on a well stimulation treatment, it should in no way interfere with the effectiveness of the operation. Economics should be considered only after all other factors have been properly evaluated. If more than one fluid will accomplish the desired result, the most economical should be used. Pretreatment and posttreatment operations should enter into any fluid selection.

Water base and acid base fluids are unquestionably the safest from the standpoint of inflammability. However, safety should be weighed with other points before choosing the fluid.

Most wells drilled are affected to some degree by "skin effect" or impaired permeability in the immediate vicinity of the drilled hole. This may be caused by invasion of drilling fluids, embedding of cuttings, or rearrangement of the formation. Fortunately, this may be overcome or even removed in some cases.

Generally, the use of a removal agent for either oil or water base muds is adequate to remedy the impairment. This corrective measure will frequently result in lower pressures during subsequent efforts to stimulate the producing formation.

There are steps that may be taken during drilling and casing installation that lesson the "skin effect". The proper conditioning of drilling fluid and modification of cementing materials may make invasion of the formation by filtrates less critical. Some care in running of drill pipe and casing can also help. If either is run too rapidly, the ram effect can cause fluid to penetrate the zone of interest with resultant damage.

An added accessory to stimulation measures is the use of surfactants as a "spearhead". Any one (or all) of three advantages may result. The possibility of troublesome emulsions may be eliminated, lower injection pressures may result, and the treating fluid may be recovered more rapidly.

Materials are available which will increase the life of a stimulation job by minimizing the formation of scale on producing equipment and in the formation. While these may not be strictly classified as stimulants, they usually are applied in conjunction with a fracturing treatment.

Polyphosphates have the ability to inhibit the precipitation of various scaling materials carried by formation waters. If slowly soluble granular polyphosphates are blended with the propping agent, the effective life of the stimulation treatment may be prolonged.

Propping Agents

Propping agents for use in well stimulation treatments are generally available in grades from 4 - 8 to 40 - 60 (U. S. Mesh). This provides a size range from 0.187 inches to 0.0098 inches in diameter. The finer grades are round grain while the coarse sands are more angular. In order to provide maximum efficiency, a propping agent should

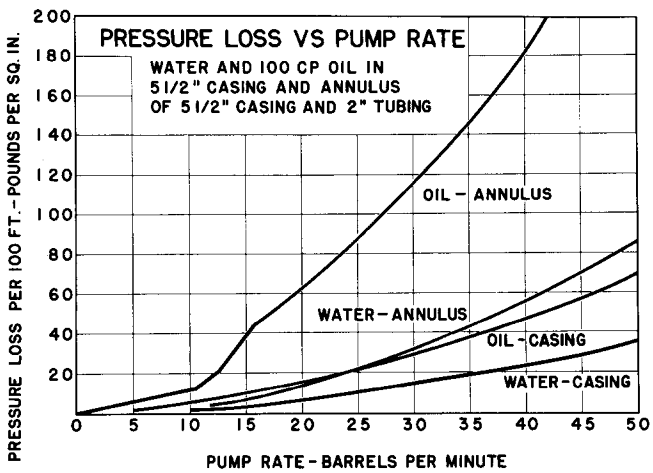
1. be rounded in shape.
2. have minimum variation in size.
3. have largest practical size.
4. have high compressive strength.
5. be free of dust or clay silt.

Economic considerations have forced some compromises in the above conditions. While there are materials that are better suited, sand is the cheapest in abundant supply.

While none of the qualities listed can be neglected, the last named is extremely important. The presence of dust, silt or fines in the sand placed in a fracture can result in the formation of a very tight emulsion. Because of a tendency for fractures to heal, the greatest long-term flow capacity will be obtained by completely packing the fracture with the largest possible sand.

STIMULATION TECHNIQUE

The many techniques for directing or placing fractures should not be overlooked. (Fig. 3). Whether the completion is open hole or perforated casing, means are available for temporarily sealing the point of entry of fluid into a formation and diverting it to another point. Viscous fluids, granular materials, perforation sealers and mechanical devices can be used to isolate zones.



After the procedures and materials most adaptable to the formation have been selected, the well should be designed to take greatest advantage of them. This may seem strange, but full economic utilization of the well equipment is frequently dependent on the effectiveness of the stimulation technique. As an illustration, if the casing is adequate for the anticipated pressure and velocity of the treatment, one or more round trips with the tubing may be saved. The saving in rig time alone would help pay the cost of better quality casing. This does not consider the intangible benefit of more effective exploitation.

Selective Perforating

Coburn and Stekoll have both advocated selective perforating with a lower density of perforations per foot.[4,5] There is abundant information to substantiate their position.[6] From the standpoint of production, it is probable that one open perforation, properly placed, would be more than capable of admitting the entire production of a high allowable well. If the perforations are too close together, there may be an inadequate barrier between perforations.

Since it is possible that the cement sheath is damaged in the immediate vicinity of the perforation and that there is some filter cake in place, conditions are very good for communication between perforations. This channeling effect is particularly noticeable with acid base materials.

If communication does exist, an unknown number of perforations may be virtually ineffective. Since the treating fluid may be diverted into a single flow channel, the produced fluid can come from the same channel.

By using a lesser number of perforations and placing them only in productive sections, there is a better chance of treating the desired zones. In addition, less treating fluid will be wasted on barren sections of formation. An added advantage may be available at a later date in remedial operations. Selective squeezing may be simplified if there is no communication between zones.

The various approaches are shown in Fig. 4. At "A", a single perforation is placed in each zone with indicated production. "B" shows several perforations utilized for the same purpose. The condition represented in "C" is little better than open hole since perforation sealers will be ineffective.

The method for fracturing treatment design proposed by Howard and Fast is mathematical in its approach. With some additional work and refinements it should prove to be a valuable addition to present methods of stimulation planning. The basis for planning includes knowledge of properties of the fluid used and of the formation to be treated.

Crittendon has presented a procedure for economical planning of fracture treatments.[2] This method is concerned primarily with determination of injection rates, pressures and energy requirements.

SUMMARY

The factors to be considered by the well owner when designing a well stimulation treatment are:

A. Formation

1. Constituents
2. Physical characteristics
3. Pressure and temperature

B. Fluid

1. Compatibility

   a. Native fluids
   b. Formation

2. Sand-carrying ability
3. Friction-loss characteristics
4. Fluid-loss
5. Economy
6. Safety

C. Fluid diversion and formation protection

D. Propping agent properties

E. Well design

1. Casing size and strength
2. Drilling practice
3. Cementing techniques
4. Perforation procedures

These should be considered separately and together. The factors are sufficiently interrelated that none should be overlooked.

The method and mechanics of the stimulation treatment should be chosen with care. A procedure should not be accepted and applied merely because it was successful in another case; nor should it be rejected because of partial failure. The final decision should be tempered by field experience.

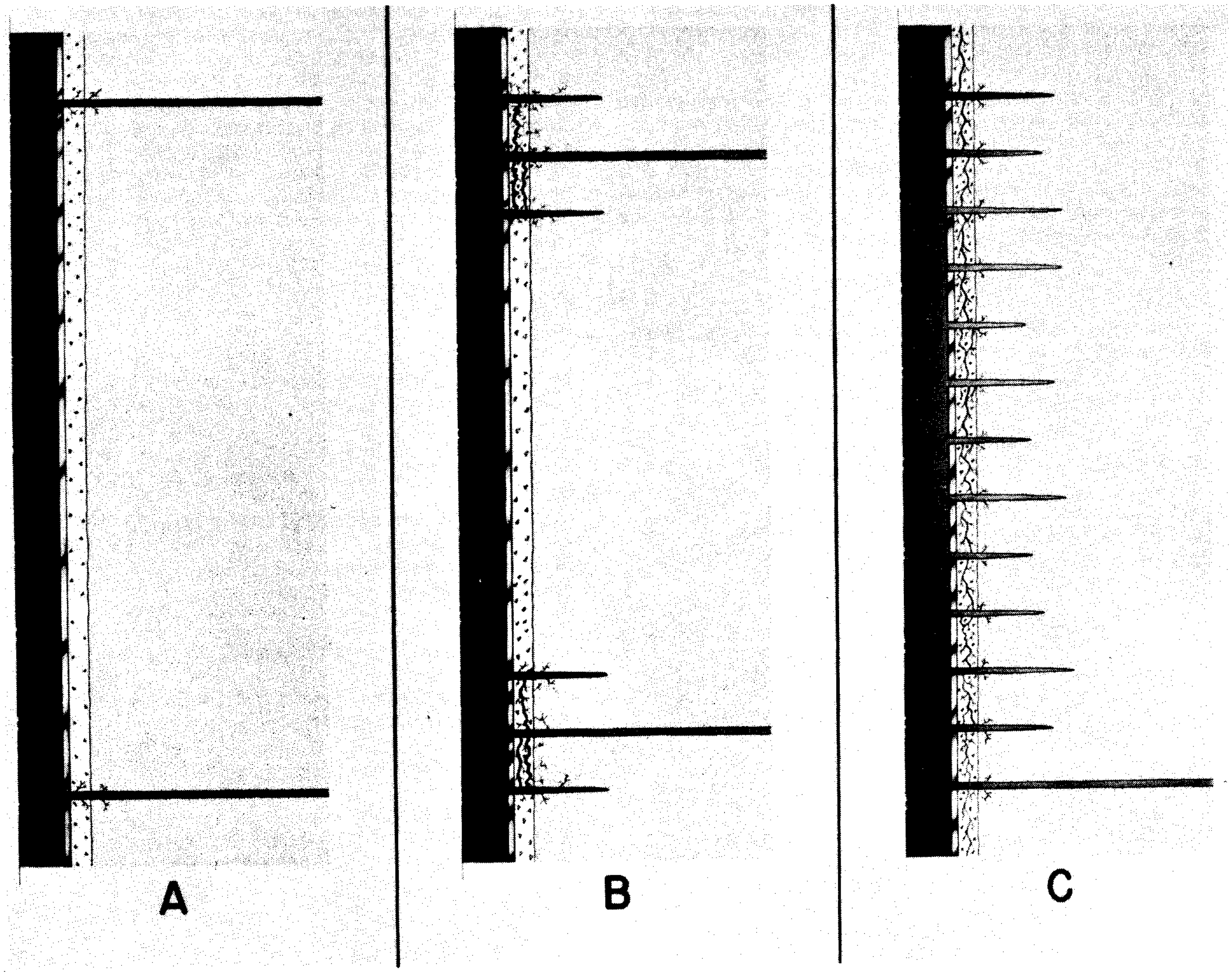


Fig. 4

ACKNOWLEDGMENT

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