The Stimulation of Oil and Gas Wells

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Any procedure used to increase the flow of fluids from a well can be called a stimulation treatment. In general, such treatments fall into two broad categories: first, those performed as a part of normal well completion and, second, remedial treatments designed to boost declining production of older wells.

The principal stimulation methods are (1) nitro blasting, (2) perforating, (3) acidizing, (4) fracturing, and (5) formation-cleaner treatments.

NITRO BALSTING

Nitro blasting, one of the earliest well stimulation techniques, consists of lowering a charge of nitroglycerin into the well until it is opposite the producing zone in the open hole. There it is set off by means of a blasting cap. The resulting explosion shatters the formation, enlarging the well bore and providing a greater drainage area.

PERFORATING

Well perforating, either by bullets or jets, can also be considered a stimulation method. Shaped charge explosives are often shot in open hole completions for the same reason that nitroglycerin is used. The shaped charge, a development of World War II, consists of a block of high explosive containing a cone-shaped indentation in one end. When the explosive is detonated, its force is concentrated into a high-velocity jet stream that punches a hole deep into the formation, through which well fluids can drain into the well bore.

ACIDIZING

The acidizing method of well stimulation is based on the fact that hydrochloric acid reacts readily with carbonate formations. The dissolving action of the acid increases formation permeability and enlarges the well's drainage area. The basic equation is as follows:

$$CaCO_3 + 2\ HCl \rightarrow CaCl_2 + H_2o + CO_2$$

The byproduct, calcium chloride, being readily soluble, is produced from the well with the spent acid; thus, no reaction products are left in the formation.

It has been determined that 1000 gallons of 15% hydrochloric acid will dissolve approximately 10.8 cu ft or 1840 lb of limestone. Acid is also effective on dolomites because, although they dissolve more slowly than limestone does, the reaction product (magnesium chloride) is soluble in water or spent acid.

Unfortunately, not all wells respond in the same manner to acidizing. Specific well conditions often present problems to the treating engineer. Chemical additives have been developed that overcome many of these difficulties. Because of the diversity of the problems and the importance of choosing the proper treating fluid and application technique, acidizing treatments should always be planned in advance. Conditions encountered in other wells in the area should be studied, in addition to any laboratory data available on cores, cuttings, and so on, from the well to be acidized.

One specialized acid available for treatments is known as low-surface-tension acid. A surface-active agent that it contains imparts special properties to the hydrochloric acid. First, by lowering the surface tension of the acid, better wetting action on the formation is provided. Thus, lower pressures are required to inject the acid into the formation, resulting in deeper penetration of small pores at lower injection pressures. Second, the wetting agent allows the spent acid to return more readily to the well bore because resistance to flow within the formation is reduced. Third, the surface-active properties impart a demulsifying characteristic to the acid, thereby tending to prevent emulsion blocks.

Many crude oils contain natural emulsifying agents. As a result, when these oils are mixed intimately with acid or spent acid, emulsion blocks may result. This problem is minimized by a demulsifying agent contained in the low-surface-tension acid. Various crudes have different emulsifying tendencies. A demulsifying agent which works effectively in one well may be completely useless in another containing a different crude. For this reason, it is advisable to run preliminary emulsion tests in a laboratory on samples of the crude oil and brine from the well to be treated. Selection of the most effective surface-active agent for the particular well can be made on the basis of these tests, thus avoiding any emulsion difficulties.

Another specialized type of acid contains silicate-control agents. This acid is for use in impure limestone or dolomite formations containing insoluble material such as quartz, anhydrite, or various clays and silicate materials. Unless proper precautions are taken, such insoluble materials may cause serious difficulties during an acidizing treatment. First of all, bentonitic clays may absorb spent acid or water, causing them to swell so that they block flow channels and offset the increased permeability resulting from the action of the acid. Also, the fine silicate particles can become stabilizers for emulsions, each fine particle acting as a nucleus for an emulsion droplet. Silicate-control agents act to eliminate these problems by forming a film around insoluble particles, preventing them from swelling or forming emulsions. Here again, prelimiary laboratory tests on formation samples will indicate whether or not a silicate-control agent is needed. In some cases, such tests spell the difference between a successful and an unsuccessful treatment.

Another specialized acid is known as "mud acid." It is designed primarily to clean up the formation after the drilling. Its purpose is to wash the face of the well bore, dissolving and disintegrating the mud cake thereon. Mud acid also acts upon any mud particles which have penetrated into the formation flow channels during the drilling. For this purpose, mud acid should be circulated down the well, spotted along the face of the producing formation, allowed to soak, then circulated out of the well. Some operators, in an effort to save time and trouble, will merely pump down the mud acid and squeeze it into the formation. This procedure is not recommended, however, especially in limestone formations.

"Stabilized acid" is another development to increase the effectiveness of acidizing. It is designed for use in formations containing appreciable amounts of iron or aluminum oxides. Such minerals may occur naturally in the formation, or they may have been carried in by injected water, or they may be the result of corrosion of metal well equipment. Such oxides are readily dissolved during an acidizing treatment. However, as the acid spends and becomes neutral, these metals reprecipitate as voluminous, spongy hydroxide. These gelatinous precipitates occupy considerable volume and act as a very effective plugging agent. Stabilized acid contains chemical additives which act as buffers, preventing the acid from spending completely to the point of neutralization, thus causing the iron and aluminum to remain in solution. Another type of additive, which may be substituted for the agent just described, acts as a complexing agent, tying up the iron and aluminum in complex ions and preventing their precipitation.

FRACTURING

The most popular stimulation method is the fracturing treatment. Its use has grown until at present about 125 wells daily are being fractured, and almost 25% of all wells have been stimulated by this method. Naturally, this technique has attracted much attention and speculation. All phases, from theory to field techniques, have undergone constant change and improvement.

The theory of fracturing dates back to the early days of nitro blasting. At that time it was realized that the production increases obtained were due, at least in part, to the cracking of the formation. Also, in the early days of acidizing, and during cement squeeze jobs, it was noted that injection pressure increased proportionally to the injection rate until a pressure break had been noted. After this point had been reached, a small increase in pressure would result in a considerably larger increase in injection rate. This same phenomenon was noted during early water flooding operations and was termed the "pressure break" or "formation parting pressure."

It is possible to calculate the theoretical pressure necessary to break down the formation, from the overburden weight, in pounds per foot of depth, plus the pressure necessary to overcome the internal tensile strength of the rock. However, such calculations are not too reliable because very few formations exhibit the homogeneity assumed in such cases. For one thing, most formations already possess some type of fracture system, ranging from horizontal to vertical or random fractures and from open fractures to fractures filled with some form of secondary deposition. Most formations also have planes of weakness, usually bedding planes or sections of high permeability.

During a fracturing treatment, fluids are injected into the producing formation at elevated pressures. Naturally, the fluid follows the line of least resistance and enters existing fractures or planes of weakness, extending, conditioning, and joining them in an open system that permits the flow of fluid and sand. In fracturing, as in acidizing, modifications in the treating materials to fit characteristics of the specific well often improve results from the stimulation treatment. Many different fracturing fluids have been developed to meet almost any conceivable well condition. Not all of these fluids can be discussed within the scope of this paper, but they can be classified into a few general groups. Basically, there are three types of fracturing fluids: (1) petroleum-base, (2) aqeous-base, and (3) mixed-base, or emulsions.

The petroleum-base fluids are crude lease oil and various fractions of refined oils, either alone or containing some thickening or gelling agent to impart increased viscosity. Aqueous-base fluids include water or hydrochloric acid, usually containing a thickening or gelling agent, but in some cases appearing in their normal, non-viscous form. The third classification, mixed-base fluids, includes the various acid/oil, oil/acid, water/oil, or oil/water emulsions which have been developed for use as fracturing fluids.

In most cases, the viscosity of the fracturing fluid is considered important because it is closely related to the fluid's sand-supporting characteristics. However, in today's high-injection-rate treatment in which the fluid is injected down the casing at 30 bpm or more, the velocity of the fluid stream is sufficient to keep the sand in suspension, enabling the engineer to use low-viscosity fluids. This has the additional advantage of avoiding the high fraction losses usually experienced when fracturing is done with high-viscosity fluids. Other important properties to be considered in the selection of a fracturing fluid are the fluid loss, the compatibility with well fluids, the flash point, and the pour point or freezing point of the fracturing fluid.

The exact role of sand in a fracturing treatment is still somewhat controversial. Some people believe that the sand injected with the fracturing fluid is carried into the fractures and remains there, propping them open after the pressure has been removed. Others contend that the sand merely scours or erodes the faces of the fractures, forming channels through which well fluids can be produced. Perhaps the true picture is a combination of these mechanisms.

A round, graded sand is considered desirable for obtaining maximum permeability following the fracturing treatment. Usually a 20-40-mesh, Ottawa sand is used. On some occasions 10-20-, 40-60-, or even 60-80-mesh sand is used, depending upon the initial permeability and hardness of the formation. Sand concentrations used vary from one-half to one pound per gallon when lease oil or water is being used as a fracturing fluid. With more viscous fracturing fluids, such as refined oils, emulsions, or gels, sand concentrations of 2 to 3 pounds per gallon have been used.

Needless to say, tremendous advances have been made in the design and capacity of fracturing equipment. High-horsepower pumping units and high-capacity blending units have been developed to meet the demand for large, high-injection-rate treatments. Here again, in the use of such high-capacity equipment, the value of preliminary planning is paramount. The treating engineer must foresee all possible problems if he is to have a smooth, trouble-free fracturing treatment. The wholehearted cooperation of the operator is of great importance.

Of increasingly widespread interest today is the concept of multiple fracturing. Basically, this type of fracturing treatment consists of running a stage of fracturing materials, followed by a temporary plugging agent to seal off the fractured zone and then followed by more fracturing materials to break down a new zone. Temporary plugging agents have been available for some time. In most cases, these plugging agents are solids which form a temporary filter cake over the face of the formation, in the zone which is accepting fluid. This filter cake diverts subsequent fracturing fluids into other, tighter zones. The plugging materials themselves are temporary in nature because they dissolve or liquefy after the fracturing treatment has been completed, leaving all zones open for production.

The latest type of temporary plugging agent, and certainly the most widely known today, is the perforation ball sealer. It should be noted that the application of these ball sealers is limited to perforated pipe, in wells known to have a good cement job without channeling. The actual number of balls to be used is still somewhat questionable. At present a number of different types of balls are available, including rubber balls, nylon balls, magnesium balls, and the most recent, a solid, nylon-core, rubber-coated ball.

FORMATION-CLEANER TREATMENTS

The final type of stimulation treatment to be discussed is confined to older wells. It is the removal of various types of deposits or accumulations which block the flow channels and reduce the productivity of the well. In most cases, field experience will indicate what the probable source of difficulty is. Suitable corrective measures can then be taken. Many things can reduce the permeability of a formation. One of the better known of these difficulties is water blocks or emulsion blocks. This blocking condition can often be alleviated by the injection of water or of acid containing suitable surface-active agents. Similarly, blocking by fine silicate particles can sometimes be corrected by the injection of stimulation fluids containing silicate-control additives.

A frequent production problem is the accumulation of paraffin deposits, both in the formation flow channels and on pumping equipment in the well bore itself. A wide variety of deposits are encountered, ranging from almost pure paraffin to complex mixtures of paraffin with asphalt, silt, sand, and various minerals. A number of commercial paraffin solvents are available, each designed for specific well conditions.

Here again, preliminary testing is advisable in order that the most efficient cleanup treatment may be provided. A common testing method is to permeate several small screens with the paraffin sample and to subject each to various types of solvent. However, care should be taken in interpreting the test results. For example, a deposit of 80% paraffin containing 20% asphalt or wax would show a rapid dissolution rate for a short time, perhaps five minutes, in a solvent designed for pure paraffin. However, if the tests were extended, 20% residue would remain, indicating incomplete removal. In contrast, a solvent designed for the asphalt component would probably have a slower initial solution rate, but at the end of perhaps 10 or 15 minutes would be completely removed.

Another production problem, especially in wells producing considerable brine along with the oil, is the secondary deposition of lime and gyp deposits in the flow channels and in the well bore itself. While, in most cases, such deposits are removable by acidizing, this is an unnecessary expense and, in any event, provides only temporary relief. A newer approach to this problem has been the prevention of such mineral deposition by injecting a suitable complexing agent, mixed with the propping sand, during a fracturing treatment. This complexing agent remains in the formation and prevents the precipitation of calcium deposits by its sequestering action. A number of such treatments have been successfully completed on wells which previously showed a rapid decline a month or so after stimulation. Following fracturing treatments containing the complexing agent, production has held up for at least six months, and these wells are not expected to scale up over periods of a year or longer.

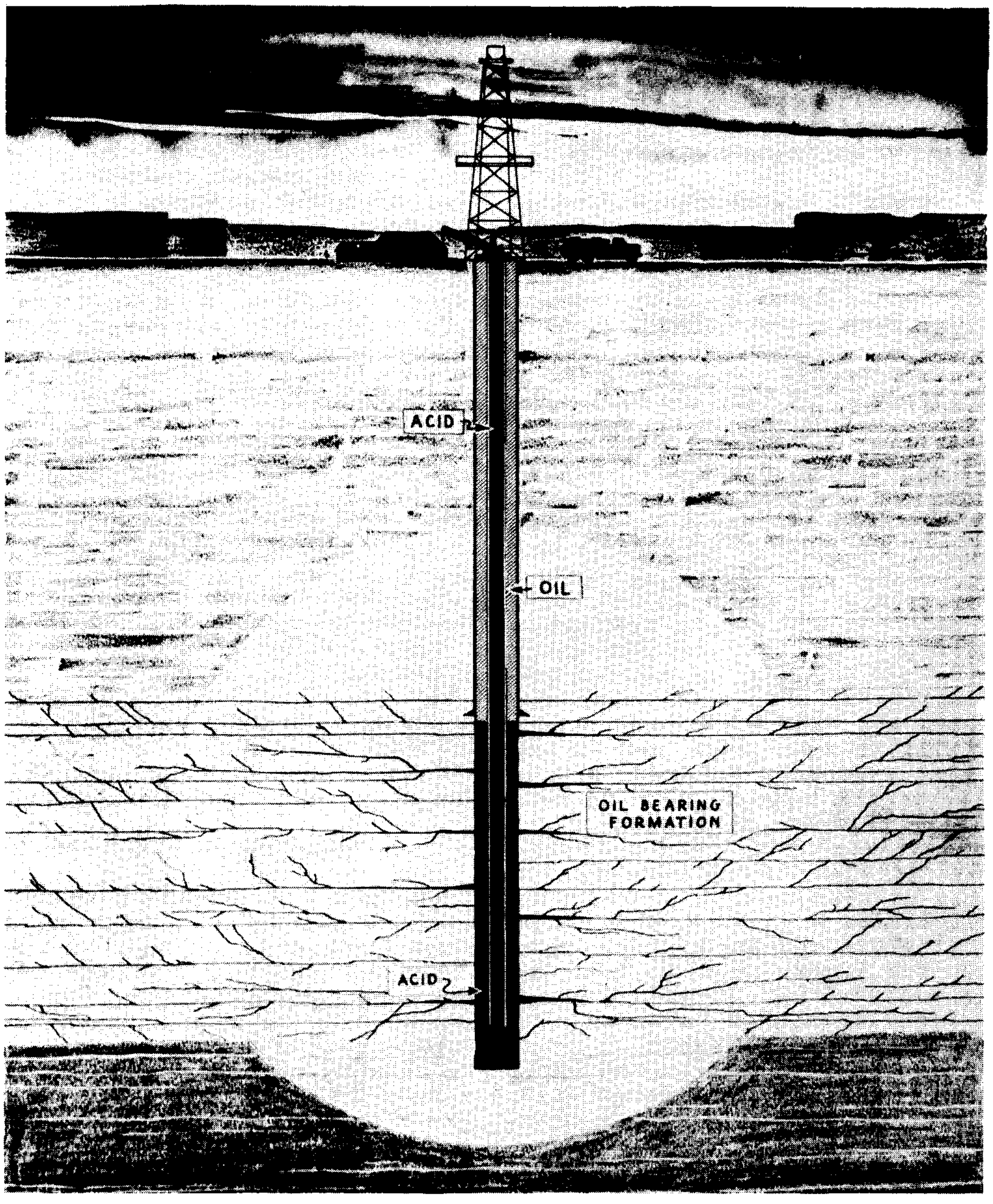

Figure 1. This schematic diagram illustrates the acidizing process. Inhibited acid is injected into the oil-bearing formation by powerful pump trucks, dissolving the rock and increasing the flow of well fluids.

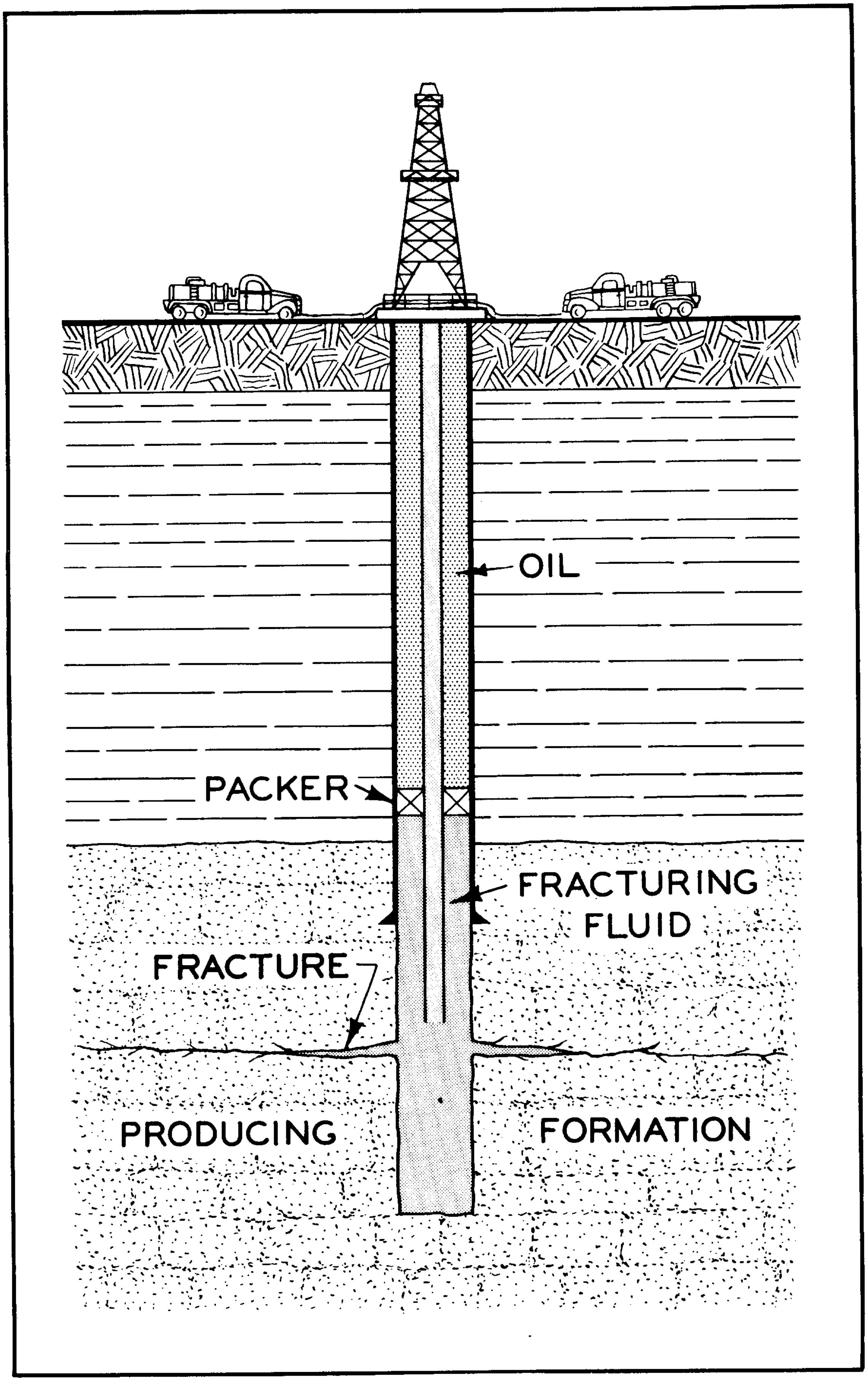

Figure 2. The fracturing process consists of injecting sand and fluid into the producing formation under high pressure, opening fissures through which well fluids may pass.