DEVELOPMENT and APPLICATION of "FRAC" TREATMENTS in the PERMIAN BASIN

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ABSTRACT

The "frac" method of well stimulation has been applied successfully to all producing formations in the Permian Basin area. During the five years since its development, many changes and improvements have been made in treating materials, procedures, and equipment.

A number of fluid carrying agents, having different physical and chemical properties, have been developed to meet various well requirements. The current trend is toward larger gallonage treatments, employing higher injection rates. The use of "down-the-casing" techniques has greatly reduced high surface working pressures, attributable to friction losses resulting from injection through tubing.

Petrographic studies of various Permian Basin formations, coordinated with laboratory and well log data, have been found a valuable guide in planning frac treatments. A knowledge of the extent and orientation of naturally occurring fractures and planes of weakness in the formation, aid in predicting the ultimate drainage pattern resulting from the frac treatment.

INTRODUCTION

The South Permian Basin covers an area in West Texas and New Mexico about one-half the size of the state of Texas. This vast region has been called the "Permian Basin" for so long that the term will be used here. It includes an area south of the Matador Arch, approximately 250 miles wide and 300 miles long. Structural features of importance within the basin are the Northwest Shelf, Eastern Platform, Midland Basin, Central Basin Platform, and Delaware Basin. The principal producing formations include sand, limestone and dolomite, with lesser amounts of shale, anhydrite, chert, and various silicates.

All of the producing formations in the Permian Basin have responded to some type of frac treatment. Essentially, a frac treatment may be defined as the injection, into a formation, of a fluid carrying agent containing a particulated solid (usually sand), for the purpose of increasing production. The application of this method of well stimulation to many differing Permian Basin reservoirs has necessitated numerous changes and improvements in carrying agents, solids, service equipment, well equipment, and treating techniques.

CARRYING AGENTS

A number of different types of fluid carrying agents have been developed since the introduction of the frac method of well stimulation. These agents have different physical and chemical properties, and in many cases the extent of production increase derived from the frac treatment depends on the choice of fluid carrier. Unfortunately, due to many different systems of nomenclature used in the oil field, these differences are not always recognized by the oil operator. In general, carrying agents may be divided into the following broad classi-

Manuscript received in Petroleum Branch office on Oct. 1, 1954. Paper presented at Petroleum Branch Fall Meeting in San Antonio, Oct. 17-20, 1954.

Discussion of this and all following technical papers is invited. Discussion in writing (3 copies) may be sent to the offices of the Journal of Petroleum Technology. Any discussion offered after Dec. 31, 1955, should be in the form of a new paper.

SPE 405-G

ncations: (1) hydrocarbon gels, (2) aqueous gels (acid or water), (3) emulsions, (4) refined oil, (5) lease oil, and (6) miscellaneous fluids.

Hydrocarbon Gels

Most hydrocarbon gels used as carrying agents are quite similar, whether made from gasoline, kerosene, diesel oil, or crude oil. They are produced by adding a gelling or thickening agent (usually a metallic soap or the salt of a fatty acid) to the hydrocarbon. This results in materially increasing the viscosity of the fluid, the extent depending upon the concentration of gelling agent added. The ability of hydrocarbon gel to suspend sand is a function of the viscosity and density of the gel, and the size and shape of the sand grains.

These hydrocarbon gels may be caused to "break" or lose their viscosity in several different ways, depending upon the type of gelling agent used. The presence of an electrolyte, such as salt water or a mineral acid, will cause most of these gels to break. Thinning of the gel may also be accomplished by dilution with additional quantities of hydrocarbon fluid.

Aqueous Gels

Water-base gels, such as thickened hydrochloric acid, are similar in many respects to hydrocarbon gels. The type of gelling agent used (usually a carbohydrate or cellulose derivative) determines how the gel breaks and what will break it. As a rule, a gelling agent is chosen which will permit the gel to break on contact with the reaction products of the acid and the formation, or as a result of bacterial growth within the gel itself. Care should be taken not to use a gelling agent that will precipitate out in insoluble form after the acid has become spent. The sand suspending ability and fluid loss characteristics of these aqueous gels are related to their viscosity and density, as in the case of the hydrocarbon gels.

Gelled acids are adaptable to a wider variety of well conditions than are hydrocarbon gels, since the type of acid and concentration may be varied, dependent on the solubility of the formation. Additional agents, which minimize emulsifying and silicate-swelling tendencies of the acid, have been used to advantage in many areas. The viscosity of the gel may be varied over a wide range as desired.

The use of gelling agents for the thickening of fresh water or brine is desirable for frac treatments on fresh water wells or water injection wells, where the injection of oily fluids might be undesirable. Such gels are thinned by bacterial action or by dilution with formation fluid.

Emulsions

The term "emulsion" until recently has been synonymous with trouble in the oil fields. When properly used, however, emulsions have been found extremely helpful. Emulsions have a number of advantages and disadvantages when compared with the gels as possible carrying agents. Although they have high fluid loss in comparison with the true gels, they possess excellent sand carrying characteristics.

Essentially, an emulsion consists of a homogeneous mixture of two immiscible fluids, one of which exists in the form of tiny droplets as the inner phase, surrounded by the other fluid known as the outer phase. Normally such mixtures rapidly separate into two distinct layers; however, certain types of chemical compounds, known as emulsifying agents, have the ability to keep such liquids in emulsion form for indefinite periods of time. Such emulsifying agents frequently occur naturally in crude oils, resulting in troublesome emulsions of crude oil and brine. Such emulsions are thick and gooey, and interfere with the production of oil from a well.

The emulsions used as carrying agents in frac treatments are physically similar to these naturally occurring emulsions; however, the emulsifying agents used produce relatively unstable emulsions which tend to break down, once they have entered the formation. The two principal emulsion type carrying agents used in frac treatments are acid/kerosene emulsions, and crude oil/water emulsions.

The physical and chemical properties of an emulsion are determined by the emulsifying agent, the volumetric ratio of the two liquids in the emulsion, and the amount of agitation given the mixture.

Acid/kerosene emulsion type carrying fluids will break down on contact with acid reaction products, or because the emulsifying agent is adsorbed onto the formation. Oil/water type emulsions may be broken by the presence of any material tending to reverse the emulsion, so that water becomes the outer phase. Most emulsions are sensitive to heat. Regular crude oil treating compounds will usually break emulsion type carrying agents. Dilution of the outer phase will thin the emulsion to a lower viscosity.

One of the chief advantages of this type carrying fluid is that an external gel-breaker is not required to cause the viscous fluid to revert to a thin, free-flowing liquid. This is particularly advantageous in low bottom-hole pressure wells, where lengthy cleanup periods are required after other type frac treatments.

In most crude oil/water type emulsions, the water and emulsifying agent make up less than 4 per cent of the total volume. Such emulsions break down in the presence of an electrolyte such as brine or acid. They are readily thinned by dilution with crude oil. If a low fluid loss carrying agent is desired, the aqueous phase of the emulsion may be made from thickened fluids. Inert solid particles also may be added to reduce the fluid loss.

Refined Oils

The term "refined oils" as used here refers to any crude oil from which the very light and very heavy hydrocarbons have been removed. This would include kerosene, heavy fuel oils, and all intermediate products. Since the heavier oil fractions are more commonly used in frac treatments, they will be discussed first.

Certain green, paraffin-base crude oils when refined properly, will yield a dark green viscous product which boils between 350°F and 750°F at atmospheric pressure. This oil fraction, commonly called "fuel oil" by refinery personnel, can be made into an ideal frac fluid by blending with a high analine point hydrocarbon, such as kerosene or diesel oil, to thin to desired viscosity.

Kerosene and diesel oil have been used as carrying agents in wells already having open fractures. Such treatments are valuable in removing paraffin deposits from the formation and wellbore or to clean up emulsions caused by a previous treatment, drilling fluid, or formation water. When used in wells where emulsion difficulties have been encountered, a demulsifying agent usually is added to the kerosene or fuel oil. It is important that preliminary tests be run to determine the proper agent to be used. Most refined oils have less tendency to form emulsions than does lease oil, due to the removal of fine solid particles by the refining process.

Care should be taken when using refined oil as a carrying agent to choose one having a pour point at least 20 degrees below the formation temperature of the well in order to avoid precipitation of wax crystals from the oil, a phenomenon taking place at 12 to 15 degrees above the pour point of the oil.

Lease Oils

At the start of most frac treatments, a volume of crude oil is pumped into the formation in order to determine the "breakdown" and feeding pressures, and the injection rate. In some cases it is possible to follow this with sand-laden crude oil, utilizing the crude oil as a carrying agent.

Such a procedure has certain advantages. For one thing, if the crude oil is from the well in which it is used, no emulsion trouble should be experienced. If a high gravity crude is used, the well should clean up readily.

Such advantages are, however, more than offset by the disadvantages attendant the use of crude oil as a carrying agent:

1. Most crude oils have very poor sand-suspending properties. Low concentrations of sand must be used or the crude will be difficult to pump and "screen-outs" are likely to occur. As a result, larger gallonage treatments and higher pumping rates are required to displace a given amount of sand into the formation.
2. The fluid loss of most crude oils is very high. Higher injection rates are required in order to accomplish the same fracture penetration obtained through the use of more viscous fluids.
3. Sand screen-outs or bridging frequently occurs when attempts are made to pump sand and crude oil through casing perforations.
4. Crude oils not native to the formation in which they are used may cause emulsion problems and difficult "clean-up."
5. A definite fire hazard exists when crude oils are handled in open tanks around pumping equipment.

Sand settling rates are much higher than those of the refined oil carrying agents. At formation temperatures the fluid loss of most crude oils is too high to be measured with standard equipment.

SAND

The exact function of the solids used during a frac treatment is somewhat controversial. Several theories have been proposed, namely, that:

1. The solid particles penetrate planes of weakness, propping them open after the carrying agent has been removed.
2. The particles act to scour or erode the walls of the passages through which they are displaced.

The solids used in a frac treatment are chosen on the basis of the following properties: particle size, shape, hardness, compression strength, permeability of a packed column, reaction with well fluid, availability, and economy. Silica sand that has been washed and screened appears to be the most practical material for this use. The most popular size is 20-40 mesh, which consists of sand grains having diameters from 0.015 to 0.030 in (0.4 to 0.8 mm).

The Humble Oil and Refining Co. has suggested the adoption of a visual roundness evaluation chart originally proposed by Krumbein.[1] This is shown in Fig. 1. Roundness is thus defined as the ratio of the average curvature of the several corners to the radius of curvature of the largest inscribed circle on the projected image of the sand grain.

The commonly used 20-40 mesh, round grain sand (see picture .6 on roundness chart, Fig. 1) has a packed permeability of 105 Darcys. In general, the larger the grain size, the greater the permeability, with angular shaped grains having a somewhat lower permeability than round grains of equal size. Field data indicate that a high degree of roundness is desirable in order to place more sand into a formation without bridging.

The concentration of sand carried in the frac fluid is governed by the equipment through which it must be pumped, the type of carrying agent, and the nature of the formation being treated. The quantities of sand and carrying agent should be carefully chosen when planning a frac treatment.

In general, the more sand displaced into the formation, the better the results will be. This holds true whether either the propping or scouring theory is applied. The maximum concentration of sand that can be handled by any particular carrying agent is dependent upon: (1) the agent's ability to support sand; (2) its fluid loss in relation to the permeability of the matrix; and (3) the anticipated injection rate.

Field experience has shown that the percentage of screen-outs has been reduced by the use of high injection rates. Another method of minimizing screen-outs has been to lower the fluid loss of the carrying agent, with respect to the formation. This is dependent upon the ability of the formation to accept the fluid being used as a carrying agent. Unfortunately, this latter factor is usually determinable only by trial and error.

The most practical approach to the problem of screen-outs is now indicated from field experience. The first step is the classification of formations into two groups: (1) those that will accept high rates of injection, and (2) those that will accept only low rates of injection, under the pressure limitations of well equipment. For the first group, high injection rates are in most cases sufficient to avoid screen-out difficulties. When treating formations which require low rates of injection, however, care must be taken to choose a carrying agent with excellent sand-supporting properties, in order to avoid the accumulation of high sand concentrations opposite the formation. Such an accumulation usually results in a complete shut-down, due to a fill-up of sand in the wellbore.

[1]References given at end of paper.

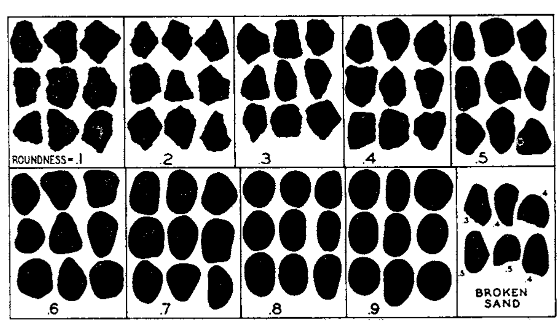

Fig. 1 — Roundness Chart for Sand.

In evaluating the sand-supporting properties of a carrying agent, the factor of temperature should not be overlooked. The majority of carrying agents, which depend upon viscosity for their sand-supporting ability, tend to thin down at elevated temperatures. Thus, the sand-suspending ability of the proposed carrying agent under conditions of bottom-hole temperature must be taken into consideration. In general, where temperatures exceeding 175° F are anticipated, and where injection rates are low due to pressure limitations of the well, it is necessary to use emulsion type carrying agents, designed for high temperature use.

EQUIPMENT

The development of frac methods of well stimulation has resulted in many changes in wellhead equipment, bottom-hole tools, pumping equipment, mixing equipment, and transporting equipment. Although at times the transition may have seemed slow, actually the change has taken place in record breaking time.

Pumping equipment has been advanced from units capable of pumping 40 gal/min at 5,000 psi, to units capable of pumping as high as 300 gal/min at 5,000 psi. These units are designed to operate for long periods of time at high pressures — up to 15,000 psi, whereas previously such pressures could be tolerated only for short intervals.

The changes in types of carrying agents employed have required the handling of highly inflammable fluids. Adequate safety precautions must definitely be made a part in the planning of any treatment. Thus far, the industry's record has been excellent, but there is still room for improvement. Specially designed fire fighting equipment is now made available on location in the form of improved extinguishers, coverings, and truck-mounted fire fighting equipment. The demand for more and better personnel protective equipment is constantly increasing. The increase in monetary loss and extent of personal injury has arisen sharply for each accident, making it essential that a cooperative and respectful attitude toward safety be prevalent among servicing personnel and personnel in charge of well equipment.

APPLICATION TECHNIQUES

A study of Permian Basin wells indicates that the two basic problems in applying various types of frac treatments are: (1) to inject the sand-laden fluid into the producing formation; and (2) to recover the carrying agent, while leaving the sand in place and the openings free from undesirable materials.

During early treatments, the accepted method of application employed the use of tubing, with several types of pack-off tools. These tools varied from single casing pack-off elements used primarily for protection of casing from high pressures, to complicated multi-pack-offs used to isolate various zones as well as protecting the casing. The use of these small treating strings (normally, 2-in tubing) limited the injection rates and consumed valuable horsepower in overcoming friction losses of the sand-laden fluid being pumped. Screen-outs of sand in the wellbore were always a hazard that had to be taken into consideration. It was believed that if higher injection rates could be obtained, larger volumes of sand could be injected before screen-outs would occur. However, the high pressures due to friction loss, prohibited the use of such high injection rates through tubing.

The first producer in the Permian Basin to use high injection rate techniques for injecting larger amounts of sand into the formation, was the Southern Production Co. Instead of applying the frac treatment through tubing, the materials were injected down the casing. Under these conditions, even though the injection rate was four times that normally used on frac treatments, the surface working pressure necessary to inject the sand-laden fluid was decreased by 50 per cent. These treatments showed that, not only was the mechanical efficiency of application improved, but the resulting production indicated that the effective increase in bottom-hole working pressures, the increased volume of materials injected, and the increased rate of injection were all beneficial to the well. As a result, these "down-casing" treatments have been extensively employed in the Permian Basin area with favorable results. On wells which contained bad casing, or had zones requiring isolation which made it necessary to inject the frac materials down the tubing, the use of larger diameter tubing (normally 3-in) was initiated by oil operators.

Field results have substantiated the fact that large volume treatments (10,000 gal or more) result in better "conditioning" of many reservoirs because:

1. Commercial producers have been obtained by large volume treatments in wells where smaller treatments failed.
2. Greater production increases have been secured with increases in the size of treatment.
3. Production declines have been slower as greater drainage area was obtained in the well.

Such higher gallonage treatments have been made possible by the use of higher injection rates during frac treatments. Such high injection rates also yield the following advantages: (1) deeper penetration of sand-laden fluids; (2) prevention of screen-outs or lock-ups at the wellbore; and (3) reduction of the effect of temperature changes on the physical properties of the carrying agent during the treatment.

It should not be inferred that frac treatments are a cure-all that eventually will replace other methods of well stimulation, such as acidizing. Some formations, especially those in a plugged condition, require an acid treatment preceding the frac treatment. Almost any zone will be benefitted by a spearhead of regular or mud acid. Such a pretreatment results in lowering injection pressures and dissolving materials that may cause restriction to flow.

Another controversial question is whether or not an overflush following a frac treatment is beneficial, and, if so, the amount of overflush which should be employed. It is believed that some overflush is beneficial because it:

1. Moves the sand back from the wellbore, to keep it from being produced.
2. Breaks emulsions that may have formed in the formation.
3. Thins refinery oil, when such has been used as a carrying agent.
4. Benefits the critical area when acid overflush is used in carbonate reservoirs. Carbon dioxide gas produced by the chemical reaction will tend to give the well initial life, reducing swab time. It is also believed that acid used for overflush will enter small "feeder" planes, further conditioning the reservoir for increased production.

Although the application of frac treatments has solved many well problems, it has also created some

TABLE 1 — RESULTS OF FRACTURING TREATMENTS IN THE PERMIAN BASIN

Well	Pay Zone	Pool	County	Well Data	Treatment Data	Results Before	Results After	Remarks
A	Rustler (sandy lime)	Keystone Colby	Winkler	Open hole 882'—1050'	20,000 gal acid 5,000 gal gelled acid 2,500 lb sand	Pumped off in 8 min	10,000 BWPD	Fresh water well used for injection program. Six alternate slugs of acid and "frac" materials used during treatment.
B	Delaware (sand)	Tunstill	Loving	5-year-old well Nitro-shot 3299'—3328'	6,000 gal lease oil/ water emulsion 9,000 lb sand Inj. rate—7 bbl/min	12 BOPD pumping	70 BOPD flowing	Test 17 days after treatment.
C	Yates (sand)	South Wickett	Ward	20-month-old well "frac" completion 2568'—2758'	9,000 gal refined oil 18,000 lb sand Inj. rate—12 bbl/min down casing	7 BOPD	518 BOPD potential 40 BOPD (after 8 mo.)	Originally completed with 2000 gal "frac" treatment for 35 BOPD.
D	Queen (sand)	Langlie-Mattix	Lea	8-year-old well Nitro (300 qts) 3410'—3587'	5,000 gal lease oil/ water emulsion 10,000 lb sand Inj. rate—10 bbl/min down casing	3 BOPD	147 BOPD flowing through 27/64" choke	No cleanout necessary after treatment in shot hole.
E	San Andres (dolomite)	Wasson	Gaines	New well 10,000 gal acid completion 5002'—5140'	10,000 gal refined oil 10,000 lb sand Inj. rate—18 bbl/min down casing	500 BOPD 3000/1 GOR	1400 BOPD potential 400/1 GOR	Inside location in old pool. Experimental job, following acid with "frac" treatment.
F	Glorieta San Angelo (dolomite)	Howard-Glasscock	Howard	New well Open hole 2775'—2995'	1,000 gal acid 3,000 gal acid/oil emulsion 6,000 lb sand Inj. rate—5 bbl/min down casing	Show	88 BOPD after 14 days	Field extension—old pool. Surface working pressure—350 psi.
G	Clearfork (dolomitic lime)	TXL	Ector	2-year-old well 10,000 gal acid completion 5460'—5910'	8,000 gal acid/oil emulsion 24,000 lb sand Inj. rate—24 bbl/min down casing	19 BOPD	187 BOPD flowing	Test on 7th day following recovery of treating fluids. No difficulty encountered.
H	Spraberry (sand and shale)	Pembrook	Upton	New well Perforated 6,000 gal hydrocarbon gel completion 7000'—7050'	20,000 gal refined oil 30,000 lb sand down casing	50 BOPD	342 BOPD flowing 220 BOPD after 18 days	Retreatment, three days after original completion.
I	Cisco	Cisco	Scurry	2-year-old well 500 gal Mud Acid completion 6180'—6212'	6,000 gal lease oil/ water emulsion 12,000 lb sand down tubing	7 BOPD	112 BOPD after 54 days	Treated below packer. 40-60 mesh sand used. Previous treatments in area, using 20-40 mesh sand, screened out.
J	Canyon (sand)	Pardue	Fisher	1½-year-old well Open hole Natural completion 4424'—4450'	250 gal Mud Acid 3,000 gal refined oil 1,800 lb sand Inj. rate—2 bbl/min down tubing	40 BOPD	118 BOPD through 12/64" choke after 5 days	In "frac" treatment of offset well, without Mud Acid, formation would not accept desired amount of sand.
K	Devonian (lime)	South Andrews	Andrews	3½-month-old well 6,000 gal acid completion 10,864'—11,059'	20,000 gal acid/ kerosene emulsion 30,000 lb sand down casing	55 BOPD	310 BOPD potential	Deepest well treated down casing, to date.
L	Waddell (sand)	Abell	Pecos	New well Perforated 5516'—5542'	3,000 gal lease oil/ water emulsion 3,000 lb sand 250 gal Mud Acid Inj. rate—3 bbl/min down tubing	Show	192 BOPD	Previous treatments in this section with other carrying agents resulted in slow "clean-ups."

new ones. One such problem which has been accentuated by frac work is that of controlling gas and water ratios.

In many cases, where relatively close orientation of water zones to the bottom of the wellbore exists, the use of special types of bottom-hole plugs has prevented increases in water production. One of the most effective procedures has been the use of a high concentration of sand in a very thick carrying liquid, spotted across the zone expected to contain planes of weakness leading to water. More recently, the introduction of oil and cement slurry squeezes has aided in this type of control by blocking off such water leading planes and diverting the frac materials into planes of weakness within the oil bearing zone.

FIELD RESULTS

A tabulation of a number of Permian Basin frac treatments is given in Table 1. This table includes well data, treatment data, and treatment results. These particular wells were chosen as being representative although the type materials and size of treatment are not necessarily recommended for these individual pools. The results are as reported from the field and are subject to correction. Some wells in these various formations responded better and others less favorably than these examples; however, the wells cited are fairly typical. Frac treatments have met with equal success in gas wells.

High surface pressures apparently are not necessary in order to obtain sustained production increases, as evidenced by a number of these case histories. One example was a San Andres well in the Howard-Glasscock Pool, with broken pay from 2,115 ft to 2,220 ft. The well, originally completed with acid in 1952, was retreated with 9,000 gal of refined oil containing 12,000 lb of sand, in May, 1954. Surface working pressure was 150 psi, at 20 bbl per minute, with the well going on vacuum when the pumps were shut down. Originally producing 2 BOPD, the well was still making 60 BOPD with some water 45 days after the treatment.

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